BEFORE THE
PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of The Dayton Power and Light Company for Approval of Its Market Rate Offer	**)))**	**Case No. 12-426-EL-SSO**
In the Matter of the Application of The Dayton Power and Light Company for Approval of Revised Tariffs	**)))**	**Case No. 12-427-EL-ATA**
In the Matter of the Application of The Dayton Power and Light Company for Approval of Certain Accounting Authority	**)))**	**Case No. 12-428-EL-AAM**
In the Matter of the Application of The Dayton Power and Light Company for the Waiver of Certain Commission Rules	**)))**	**Case No. 12-429-EL-WVR**
In the Matter of the Application of The Dayton Power and Light Company to Establish Tariff Riders	**)))**	**Case No. 12-672-EL-RDR**

DIRECT TESTIMONY

OF

JONATHAN A. LESSER

ON BEHALF OF

FIRSTENERGY SOLUTIONS CORP.

March 1, 2013

PUBLIC VERSION

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I. INTRODUCTION, PURPOSE, AND SUMMARY OF CONCLUSIONS

Q. PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Jonathan A. Lesser. I am the President of Continental Economics, Inc., an economic consulting firm that provides litigation, valuation, and strategic services to law firms, industry, and government agencies. My business address is 6 Real Place, Sandia Park, NM 87047.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL QUALIFICATIONS, EMPLOYMENT EXPERIENCE, AND EDUCATIONAL BACKGROUND.

A. I am an economist with substantial experience in market analysis in the energy industry. I have almost 30 years of experience in the energy industry working with utilities, consumer groups, competitive power producers and marketers, and government regulators. I have provided expert testimony before numerous state utility commissions, as well as before the Federal Energy Regulatory Commission ("FERC"), state legislative committees, and international venues.

Before founding Continental Economics, I was a Partner in the Energy Practice with the consulting firm Bates White, LLC. Prior to that, I was the Director of Regulated Planning for the Vermont Department of Public Service. Previously, I was employed as a Senior Managing Economist at Navigant Consulting. Prior to that, I was the Manager, Economic Analysis, for Green Mountain Power Corporation. I also spent seven years as an Energy Policy Specialist with the Washington State Energy Office, and I worked for Idaho Power Corporation and the Pacific Northwest Utilities Conference Committee (an electric industry trade group), where I specialized in electric load and price forecasting.

I hold MA and PhD degrees in economics from the University of Washington and a BS, with honors, in mathematics and economics from the University of New Mexico. My doctoral fields of specialization were applied microeconomics, econometrics and statistics, and industrial organization and antitrust. I am the coauthor of three textbooks: *Environmental Economics and Policy* (1997), *Fundamentals of Energy Regulation* (2007), and, most recently, *Principles of Utility Corporate Finance* (2011). I have attached a copy of my curriculum vitae as Exhibit JAL-1.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL ORGANIZATIONS?

A. Yes. I am a member of the International Association for Energy Economics, the Energy Bar Association, and the Society for Benefit-Cost Analysis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of FirstEnergy Solutions Corp. ("FirstEnergy Solutions" or "FES").

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO ("PUCO")?

A. Yes. I testified in Case Nos. 08-917-EL-UNC and 08-918-EL-UNC, generally referred to as the "AEP POLR Remand" proceeding. I also testified in Case Nos. 11-346-EL-SSO, 11-348-EL-SSO, 11-349-EL-AAM and 11-350-EL-AAM, in Case Nos. 11-501-EL-FOR and 11-502-EL-FOR, and in Case No. 10-2929-EL-UNC.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony addresses several aspects of Dayton Power & Light's ("DP&L" or "the company") proposed Electric Service Plan ("ESP").[1] Specifically, I find that:

1. DP&L's proposed $138 million[2] annual Service Stability Rider ("SSR") is inappropriate, unsubstantiated, and anticompetitive. The company admits the market changes first introduced over a decade ago by the PUCO following passage of S.B. 3 were "introduced in a reasonable, transparent and straightforward manner, which has permitted the affected utilities to adapt to the new requirements."[3] As such, there is no rational economic or regulatory basis to continue subsidizing the company's generating resources, which have been treated as a competitive business activity for a decade. Indeed, DP&L's failure to achieve corporate separation of its generation assets on a reasonable timeline in order to protect its regulated services from its unregulated generation services, despite receiving over $400 million in transition payments during the 2002 – 2004 timeframe,[4] is DP&L's failure alone and should not be used now to justify massive subsidies for those same unregulated generation services.

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[1] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan,* October 5, 2012 ("DP&L MRO").

[2] In Exhibit CLJ-2, DP&L witness Craig Jackson states that the $137.5 million SSR value has been rounded up to $138 million in that (and other) schedules. For ease of exposition, and because Prof. Chambers uses this same rounded value in his testimony and exhibits, I use the rounded value in my testimony.

[3] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan,* Second Revised Direct testimony of William Chambers, December 12, 2012 ("Chambers Direct"), p. 24, lines 14-16.

[4] DP&L claims it has no available information on transition payments received by the company prior to 2002. *See* DP&L's responses to OCC-407 and OCC-408 (attached as Exhibit JAL-2).

DP&L claims the SSR is needed to maintain the company's financial integrity and that the company's access to financial markets will be restricted without the SSR, raising the cost of financing its regulated transmission and distribution ("T&D") functions. Even if true, however, a possible downgrade in DP&L's credit rating does not provide a legitimate basis for the PUCO to subsidize DP&L and, regardless, DP&L's claims are not supported by its own testimony. DP&L relies on a flawed "pro forma" analysis prepared by DP&L witness Chambers to justify the SSR. Prof. Chambers's pro forma analysis ignores reductions in capital and operations and maintenance ("O&M") expenditures identified by DP&L witness Jackson, but not incorporated into Exhibits CLJ-2 through CLJ-4, and potential revenues and profits from DP&L's wholesale sales, which are similarly not reflected in Mr. Jackson's financial projections, nor in Prof. Chambers's pro forma analysis. Thus, the pro forma analysis presents a wholly unsubstantiated and deceptive picture of DP&L's financial integrity.

The SSR is also anticompetitive, because it forces all DP&L customers to continue to subsidize DP&L's functionally separated competitive generating resource activities, and enhances the ability of DP&L to cross-subsidize its retail marketing subsidiary's activities.

DP&L admits its profit margins in the competitive generation market are lower than its regulated returns and admits the SSR will provide additional compensation for its competitive generation assets. Competitive generation markets provide companies with economic incentives to enhance operating efficiency and lower costs to benefit consumers. By imposing a nonbypassable SSR, DP&L will also discourage retail competition, contrary to long-established Ohio policy. Market competition is incompatible with subsidies that guarantee a level of profitability, which is precisely what the SSR will provide DP&L. The SSR should be rejected in its entirety.

Because DP&L witness Jackson states that the company's distribution system revenues are adequate to provide safe and reliable service, DP&L's financial integrity can be addressed more quickly and at a much lower cost to all DP&L customers through full structural separation, rather than implementing an anticompetitive SSR. Although DP&L claims that it would incur unspecified costs if required to complete structural separation prior to December 31, 2017, DP&L has not shown that any such alleged costs would exceed the cost of the SSR and Switching Tracker. Indeed, DP&L has not shown that it will not incur equivalent costs in 2017 as compared to 2014 or today. DP&L should be required to structurally separate its competitive generation business by no later than December 31, 2014, which leaves more than enough time for DP&L to obtain any required regulatory approvals.

2. DP&L's proposed Switching Tracker is anticompetitive. First, it reduces the incentive for customers to switch to competitive retail electric service ("CRES") providers. The more customers who switch, the more these, and DP&L's SSO customers, will be required to pay for customers having exercised their right to switch. Second, the Switching Tracker is simply another "bite at the apple" that DP&L argues is required to maintain its financial integrity. Again, the financial integrity of DP&L's T&D

operations can be addressed more easily and at a lower cost by requiring DP&L to structurally separate all of its generating resources.

3. DP&L's proposed Alternative Energy Rider ("AER-N") placeholder, which DP&L witness Seger-Lawson admits is for recovering the cost of DP&L's Yankee Solar facility, is anticompetitive, unjustified, and will damage the Ohio economy.[5] If DP&L is allowed to include the costs of its Yankee Solar facility in the AER, it will effectively force customers who purchase their electricity from CRES providers to pay twice for renewable energy required under Ohio's renewable portfolio standard ("RPS") requirements. There is no evidence DP&L's Yankee solar generation facility meets the clear resource planning guidelines under Ohio Rev. Code § 4928.143(B)(2)(c). DP&L claims the PUCO's approval of a stipulation in its 2010 Long-Term Forecast Requirement ("LTFR") filing is evidence of the "need" for Yankee Solar.[6] It is not. The findings made in the 2010 LTFR proceeding are outdated, stale, and no longer accurate. Indeed, the load forecast submitted by DP&L in that proceeding is significantly higher than the forecast submitted in the instant proceeding and in DP&L's 2012 LTFR filing. Moreover, DP&L's 2010 LTFR submittal suggested only that additional solar facilities would be needed in Ohio for compliance with the benchmarks in R.C. § 4928.64. DP&L did not demonstrate that Yankee Solar was "needed" for purposes of R.C. § 4928.143(B)(2)(c) because there

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[5] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan,* Second Revised Direct testimony of Dona Seger-Lawson, December 12, 2012 ("Seger-Lawson Direct"), p. 18, lines 6-13.

[6] *In the Matter of the Long-Term Forecast Report of Dayton Power and Light Company and Related Matters*, Case No. 10-505-EL-FOR, Order Accepting Stipulation, April 19, 2011.

was no showing that DP&L's generation needs could not be met through the competitive market. Moreover, since January 1, 2009, 75 MW of solar photovoltaic resources have been approved by the PUCO for development in Ohio, which will provide an estimated 94,700 MWh of in-state solar renewable energy credits. According to data compiled by PUCO staff, in 2012 alone, the PUCO approved over 32 MW of new solar facilities.[7] Based on updated data, including DP&L's 2012 LTFR filing and the retail switching values used by the company in this ESP proceeding, the amount of in-state solar development that has already taken place exceeds DP&L's projected need for in-state solar resources in the year 2022 by almost 800%.

All costs associated with the Yankee Solar facility, and any other renewable energy facilities DP&L may construct in the future, should be treated like all other renewable resources under Ohio Rev. Code §4928.64 and be fully bypassable. Establishing a "placeholder" AER at this time is not only unnecessary, but will also stifle market competition because of the uncertainty it creates for DP&L customers and the renewable energy market.

4. DP&L's proposed nonbypassable Reconciliation Rider ("RR") is anticompetitive. First, it is designed to recover costs associated with DP&L's competitive bidding process ("CBP") to serve SSO load, i.e., non-switching customers. There is no economic rationale to require customers who have switched to CRES providers to pay

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[7] *See* http://www.puco.ohio.gov/puco/index.cfm/puco-forms/renewable-energy-resource-generating-facility-application-for-certification/ (accessed January 8, 2013).

for the costs of the CBP. Second, DP&L should not be allowed to recover the costs associated with deferral balances on a nonbypassable basis. These deferral balances are related to charges that are fully bypassable today. Moreover, the proposed 10% threshold creates a perverse incentive by encouraging DP&L to allow the deferral balances to increase so that the company can recover them on a nonbypassable basis, contrary to sound business practice. Finally, because DP&L cannot demonstrate specific cost-causation for these deferral balances to customers who take service from CRES providers, they should be treated as a cost of business.

5. DP&L's continued reliance on functional separation of its competitive and regulated businesses is inferior to structural separation in terms of providing the benefits of competition to customers. There are at least four separate flaws associated with DP&L's proposed functional separation, including:

   a. Functional separation is the cause of DP&L's concerns over its "financial integrity." These concerns can be addressed more easily and at a far lower cost through full structural separation.

   b. There is significant risk of cross-subsidization through the improper allocation of revenues and costs between DP&L's regulated T&D business and its competitive generation business. This is especially true because DP&L admits it does not maintain separate, audited ledgers for these two businesses. Full structural separation will increase financial transparency and thus greatly reduce any potential for improper and anticompetitive cross subsidies.

   c. There is significant risk of improper sharing of competitive information among regulated and unregulated business activities.

d. Cross-subsidization and improper sharing of competitive information are particularly problematic with respect to the CBP, as such concerns can reduce the interest of potential suppliers and ultimately lead to higher prices for customers.

Absent a comprehensive structural solution to these problems, DP&L and its corporate parent's ("DPL, Inc.") retail subsidiaries, DPL Energy Resources ("DPLER") and MC Squared, should be prohibited from participating in the DP&L CBP.

II. THE SSR SHOULD BE REJECTED

Q. SHOULD THE $138 MILLION NONBYPASSABLE SSR BE APPROVED?

A. No. DP&L argues that it must collect the SSR to maintain its "financial integrity." In making this argument, not only does DP&L apply inconsistent measures of "financial integrity," but it also asks all of its customers to continue subsidizing its competitive generating business for an additional five years. In fact, DP&L admits that its profit margins on competitive generation sales are lower than those sales as a monopoly utility. In his deposition, DP&L witness Jackson states, "[g]iven the current market conditions, I do not believe that the generation assets could be separated out separately and be financed with, you know, a certain level of debt."[8] Thus, DP&L is asking the PUCO to require all DP&L customers, including those who shop for competitively supplied generation, to subsidize its competitive generating assets for an

[8] Deposition of Craig Jackson, 2/15/2013 ("Jackson Deposition 2/15/2013"), p. 70.

additional five years because it believes the market value of that generation is too low to sustain a separate corporate entity.

DP&L's request is at odds with wholesale and retail electric competition: which provides generators with the competitive market incentives to improve the efficiency of their operations, reduce their costs, and manage the financial risks of their generating asset decisions, rather than force captive customers to bear those risks. In effect, DP&L is asking the PUCO to allow it to earn above-market returns on its competitive generating assets while the company simultaneously competes in wholesale and retail markets, including for its own customers who decide to take power from CRES providers. In 2011, DPLER provided 87% of all sales to DP&L customers who switched to CRES providers.[9] In asking for the SSR and the Switching Tracker, DP&L is demanding all of its customers, including those who purchase electricity from CRES providers, to subsidize DP&L's competitive operations, which is antithetical to true market competition and blatantly anticompetitive.

A. <u>Market Competition Does Not Guarantee Financial Integrity</u>

Q. HOW DO YOU DEFINE "FINANCIAL INTEGRITY?"

A. I define "financial integrity" as a company's ability to remain a "going concern." In other words, "financial integrity" means a company can meet its operating expenses, service its debt, be able to make needed capital investments and provide investors with an expected return that is comparable to the returns earned by firms facing comparable

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[9] *See* Response to IEU Request for Admission 1-10, attached as Exhibit JAL-3.

business and financial risks. This definition is how the U.S. Supreme Court defined financial integrity in its well-known *Hope Natural Gas* decision.[10]

Q. DOES MARKET COMPETITION GUARANTEE A COMPANY WILL MAINTAIN ITS FINANCIAL INTEGRITY?

A. Of course not. The rigor of the marketplace provides a financial incentive for companies to innovate, improve productivity and operating efficiency, and reduce their costs, because doing so leads to higher profits. If a company is told its financial integrity is guaranteed, then the economic incentive to improve its operations and reduce costs is reduced.

Q. DOES DP&L WITNESS CHAMBERS ARGUE THAT THE TRANSITION TO COMPETITION IN OHIO WAS UNJUST AND UNREASONABLE AND, CONSEQUENTLY, DP&L'S RATEPAYERS SHOULD BE FORCED TO PAY $687.5 MILLION IN ADDITIONAL COMPENSATION TO THE COMPANY THROUGH THE SSR, PLUS ADDITIONAL MONIES THROUGH THE SWITCHING TRACKER?

A. No. In fact, Prof. Chambers testifies the transition was reasonable and transparent, stating:

> Over the past ten years, the Commission has been in the process of implementing a wide series of initiatives affecting Ohio electric utilities, most especially regarding the introduction of competition in generation …. While the actual and potential effects of such changes are indeed likely to be substantial, the changes appear to have been introduced in a reasonable, transparent and straightforward manner, which has permitted the affected utilities to adapt to the new requirements.[11]

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[10] *Federal Power Comm'n. v Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("Hope Natural Gas"). "The return to the equity owner … should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital." *Id*. at 603.

[11] Chambers Direct, p. 24, lines 8-16.

Thus, Prof. Chambers argues that, despite a transition to competition over the last ten years—a transition he admits has been "reasonable, transparent and straightforward" —and despite recovering over $400 million in stranded generation and other regulatory costs during that transition period that might otherwise not be recoverable in a fully competitive market and an opportunity to separate its higher-risk generation assets into a competitive affiliate, the PUCO is nevertheless <u>obligated</u> to provide DP&L with at least $687.5 million in additional revenues the next five years through a nonbypassable SSR to subsidize DP&L's generating assets and maintain the company's "financial integrity."

There is no legitimate regulatory or economic rationale to support DP&L's request for additional ratepayer monies.

Q. ARE SSR REVENUES DESIGNED TO COMPENSATE DP&L FOR ITS COMPETITIVE GENERATION-RELATED COSTS?

A. Yes. In response to IEU Interrogatory 1-39 (attached as Exhibit JAL-4), DP&L states, "DP&L's Service Stability Rider ("SSR") is designed to ensure DP&L's financial integrity, and therefore may provide compensation for generation costs." DP&L admits its generating resources are treated as competitive assets, not regulated ones. Furthermore, in his deposition, DP&L witness Jackson admits that DP&L's regulated T&D service revenues are adequate over the ESP time frame.

> 17 Q. Do you have any reason to believe that
> 18 DP&L's distribution revenues are inadequate?
> 19 MR. FARUKI: Over what period of time,
> 20 Jim? Today, or some period?
> 21 Q. Today and over the ESP period, 2013
> 22 through 2017.
> 23 A. In my opinion, I believe that the

revenues for the distribution business as we've outlined in the forecast or in the ESP filing are adequate.
Q. Would the same be with respect to transmission revenues?
A. I believe they are adequate across transmission, distribution, and generation including the SSR.[12]

Mr. Jackson's admission that T&D service revenues are adequate means that the sole source of "inadequate" revenues must be DP&L's competitive generating assets. Indeed. in his deposition, Mr. Jackson also opines that the generation assets cannot support any debt today because the market value of the generating assets is too low. Hence, DP&L could not "assign" debt at the time of corporate separation to what will be the unregulated generation company.[13]

Furthermore, Mr. Jackson discusses capital expenditures that DP&L projects, for purposes of the ESP filing, it may make on its coal-fired generating plants in the 2015-2017 timeframe, which he admits could be delayed.[14] There is a financial incentive for DP&L to make those investments before corporate separation, because they would be underwritten by DP&L's distribution customers and would provide additional market value to which debt could be allocated. Clearly, the SSR revenues will provide DP&L a greater financial cushion that would allow the company to proceed with investments that Mr. Jackson admits could be delayed. This is simply an "end-run" around the market

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[12] Jackson Deposition, 2/15/2013, pp. 100 – 101.

[13] *Id.*, pp. 80 – 81.

[14] *Id.*, pp. 129 – 130.

forces faced by all other competitive generation providers in the form of additional subsidies.

Q. DO YOU CONCLUDE THE SSR'S REAL PURPOSE IS TO HELP DP&L SUBSIDIZE ITS COMPETITIVE GENERATION ASSETS AND ENABLE THOSE ASSETS TO BE SPUN OFF EVENTUALLY INTO A SEPARATE COMPANY?

A. Yes. Despite Prof. Chambers's admission that the transition to competition was "reasonable, transparent and straightforward," DP&L still maintains the PUCO is obligated to guarantee the company's financial integrity, including subsidies for its competitive generating assets. As Mr. Jackson has testified, however, DP&L's competitive generating assets are not financially viable. Thus, DP&L wishes to wait for more favorable market conditions to separate those generating assets, while relying on customers to subsidize those investments in the meantime.[15]

In essence, DP&L witness Jackson admits that DP&L customers should subsidize the company's competitive generation assets in order to increase their market value at the time of structural separation. This is the equivalent of forcing customers to pay for improvements to a "fixer-upper" home in order to increase its market value and allow a larger mortgage to be taken out on the property.

There is no legitimate regulatory or economic rationale to force all DP&L customers to <u>subsidize</u> competitive generating assets for an additional five years, as DP&L proposes in its ESP. In fact, based on DP&L witness Jackson's rationale for continued subsidization of the company's competitive generation, if market conditions do

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[15] *Id.*, p. 71. "We are looking at potential recovery in the commodity market to bridge us to 2017."

not improve sufficiently by the end of the ESP period in five years, DP&L would presumably request additional generation subsidies. The potential for indefinite subsidization of DP&L's competitive generation makes a mockery of wholesale and retail electric competition in Ohio.

Q. HOW DO YOU RESPOND TO DP&L'S CLAIM THAT THE PROPOSED SSR IS DESIGNED TO MAINTAIN THE FINANCIAL INTEGRITY OF DP&L'S REGULATED T&D BUSINESSES, AND NOT JUST ITS COMPETITIVE GENERATION ASSETS?

A. If DP&L structurally separates its competitive generation operations from its regulated T&D operations, the remaining "poles and wires" company would be fully regulated and entitled to just compensation based on traditional regulatory principles and prohibitions against regulatory takings. DP&L's attempt to delay structural separation until 2018 is simply a way for the company to continue to subsidize its competitive generation operations. Such subsidies are anticompetitive, contrary to well-established regulatory policy, and contrary to Ohio law promoting competitive electric markets.

Q. WON'T THE SSR SUPPORT THE FINANCIAL INTEGRITY OF THE SINGLE INTEGRATED COMPANY?

A. DP&L maintains this position in its responses to interrogatories OCC-444 and OCC-446 (attached as Exhibit JAL-5), which is disingenuous. If DP&L were a stand-alone, fully regulated local distribution company, there would be no question about maintaining the company's "financial integrity." DP&L would file its regulated cost of service in a standard rate filing with the PUCO. The PUCO then would determine an allowed return on equity and overall return on capital investment consistent with the "comparable risk" tenets of *Hope Natural Gas*.

Instead, DP&L seeks to use the issue of its ongoing "financial integrity" as a smokescreen, designed to allow its competitive generation function to be subsidized by all ratepayers for an additional five years. Although, in its response to OCC-446, DP&L states the purpose of the SSR and switching trackers is not to subsidize its retail generation services, as discussed above, in its response to interrogatory IEU 1-39, DP&L admits the SSR will provide revenues to its competitive generation function. Because that competitive generation provides all of the generation its retail affiliate, DPLER, sells to retail customers, the SSR clearly <u>will</u> subsidize DP&L's retail generation service through DPLER.

Q. CAN DP&L FILE A DISTRIBUTION RATE INCREASE IF THE COMPANY BELIEVES IT NEEDS ADDITIONAL CAPITAL TO PROVIDE SAFE AND RELIABLE ELECTRIC SERVICE?

A. Yes. DP&L is not prohibited from filing for a distribution rate increase if the company believes it requires additional monies to make new capital investments and increase distribution O&M expenses to ensure safe and reliable distribution service. Even if DP&L receives the SSR and Switching Tracker subsidies, it has not promised that it won't seek a distribution rate increase during the ESP term. In fact, "Technical Accounting Memorandum" dated January 15, 2012, Bates No. DPL 0054718 – 0054728 (attached as Confidential Exhibit JAL-6), states [**BEGIN CONFIDENTIAL**] "[redacted]"[16] [**END CONFIDENTIAL**]. Filing this rate case will clearly affect the revenues DP&L collects for distribution service and, thus,

[16] *See* Bates No. DPL 0054725.

affect the financial projections prepared by DP&L witness Jackson and the pro forma financial integrity analysis prepared by DP&L witness Chambers.

Q. DOES MR. JACKSON'S TESTIMONY DISCUSS THE IMPACTS OF FILING A DISTRIBUTION RATE CASE IN 2013 ON THE COMPANY'S FINANCIAL INTEGRITY?

A. No.

Q. DOES MR. JACKSON'S TESTIMONY DISCUSS THE IMPACTS OF FILING A DISTRIBUTION RATE CASE IN 2013 ON THE COMPANY'S ABILITY TO PROVIDE STABLE ELECTRIC SERVICE?

A. No. Presumably, in that rate case filing, DP&L will include known and measurable distribution capex and additional O&M expenses needed to ensure its distribution system is safe and reliable.

Q. IS DP&L REQUIRED TO OWN ITS GENERATING ASSETS TO PROVIDE SAFE AND RELIABLE SERVICE?

A. No. DP&L can purchase all of its generation requirements from the PJM energy market or through bilateral transactions with other generation owners.

B. DP&L Witness Jackson's ESP Projections Exaggerate Costs and Ignore Wholesale Profits

Q. WHAT IMPACT DOES THE SUBSIDY FOR DP&L OVER THE NEXT FIVE YEARS HAVE ON DP&L'S CAPITAL AND O&M EXPENDITURES?

A. If DP&L's financial integrity is threatened, as witnesses Jackson and Chambers allege, one would expect the company to identify capital expenditures ("capex") that could be delayed or eliminated. And, in fact, DP&L has identified both capex and O&M

expenditures that could be reduced. In Mr. Jackson's deposition he testified regarding an internal "Impairment Analysis" White Paper. [17] DP&L determined the company could reduce capex by [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[18] According to Mr. Jackson, this impairment analysis was related solely to DP&L's competitive generating assets.[19] Furthermore, in his deposition, Mr. Jackson stated that DPL, Inc. had also identified reductions in O&M expenditures of [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].[20] Mr. Jackson also stated that the O&M expense reductions were "more heavily weighted on the generation side."[21] Together, these expenditure reductions identified by DP&L total more than the annual SSR the company is requesting.

Yet, neither Mr. Jackson's Exhibits nor Prof. Chambers's pro forma analysis, which is based on that same exhibit, reflects these reductions in capex and O&M

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[17] The confidential Impairment Analysis White Paper, which was prepared on October 2012, was provided by DP&L as Bates Nos. DP&L 0053703 – 0053738 (attached hereto as Exhibit JAL-7).

[18] Jackson Deposition, 2/21/2013, p. 279. Mr. Jackson is referencing the Impairment Analysis White Paper, and the capex reduction discussion on Bates No. pages 0053721 – 0053722 of that document. *See* Exhibit JAL-6. [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].

[19] Deposition of Craig Jackson, 2/21/2013 ("Jackson Deposition, 2/21/2013"), p. 240.

[20] Jackson Deposition, 2/21/2013, pp. 320 – 321. In his deposition, Mr. Jackson stated the 2014 value was [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. However, in his deposition on 2/25/2013, he stated the value was [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].

[21] *Id.*, p. 322.

expenditures. Instead, Mr. Jackson's analysis shows significant <u>increases</u> in capex over the five-year period.[22]

Q. WHAT CAPEX INCREASE HAS DP&L FORECAST FOR PURPOSES OF ITS ESP FILING?

Mr. Jackson projects that DP&L's capex in 2016 will be $104 million greater than its projected 2013 capex.[23] The bulk of these projected increases in capex are for DP&L's competitive generating assets, as well as transmission system investments listed by DP&L as PJM Regional Transmission Expansion Plan ("RTEP") projects.

For example, Mr. Jackson shows RTEP capex increasing from [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. Nor, in his deposition, did Mr. Jackson know what those projects referred to.

> 3 Q. Now, for 2015, '16, and '17 a sizeable
> 4 portion of what's in that Transmission - RTEP
> 5 category is "TBD." So is that to be determined?
> 6 A. There are some additional items that the
> 7 detail is just not listed here that that makes up.
> 8 Q. So that would be a budgeted amount but
> 9 there's not a particular transmission project that
> 10 has been allocated that budget as of the time this
> 11 was prepared anyway?

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[22] These data are contained in the confidential spreadsheet "Financial Support Document – Craig 12-20-2012.xls," which was provided in response to OCC-18, RFPD-64.

[23] Jackson Direct, Exh. CLJ-4 (the "Net cash used for investing activities" on line 4 is projected capex).

12 A. I will have to confirm that.
13 Q. You don't know?
14 A. I believe there are additional projects
15 that have just not -- it's not listed out, so I will
16 have to confirm that.
13 Q. You don't know?
14 A. I believe there are additional projects
15 that have just not -- it's not listed out, so I will
16 have to confirm that. [24]

Similarly, DP&L projects generation capex to increase from [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**].

Q. DOES A REDUCTION IN CAPEX LEAD TO ANY OTHER COST REDUCTIONS?

A. Yes. A reduction in capex means a lower total of depreciable capital investment. For a fully regulated utility, this means a lower rate base. Less total capital investment would also reduce DP&L's annual depreciation expense, which DP&L projects will increase from [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**]. With DP&L projecting total capex of over [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] over the five-year ESP period, the potential depreciation savings from capex reductions are significant. The amount of the depreciation expense reduction will depend on the assumed service life of the capital investments.

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[24] Jackson Deposition, 2/15/2013, p. 127.

Q. HOW WOULD A REDUCTION IN CAPEX AND O&M EXPENSES AFFECT DP&L'S PROJECTED BALANCE SHEET AND STATEMENT OF CASH FLOWS?

A. A reduction in capex will reduce the values shown in Exhibit CLJ-3, line 5 ("Property, Plant, and Equipment") and line 6 ("Accumulated depreciation and amortization"). This implies a reduction in line 7 ("Total Property, Plant, and Equipment" and line 11 ("Total Assets"). Because DP&L would use less cash for new capital investments, this would increase retained earnings and, therefore, line 18 ("Common Shareholder Equity").[25]

The reduction in capex and O&M expenses would be reflected on the Projected Statements of Cash Flows, shown in Exhibit CLJ-4. Specifically, a reduction in O&M expenses will increase line 2 ("Net Cash provided by operating activities"), as will a reduction in depreciation expense and property taxes paid on the lower overall levels of capital investment each year. The reduction in capex will be reflected on line 4 ("Net cash used for investment activities"). The combined effect will be to increase the values shown on line 11 ("Cash and cash equivalents at end of period"). That, in turn, affects dividend payments and total shareholders' equity. Based on the Impairment Analysis White Paper prepared by DP&L and statements made by Mr. Jackson regarding annual reductions in O&M expenses, the increase in "Cash and cash equivalents at end of period" on line 11 of Exhibit CLJ-4 could be as high as [**BEGIN CONFIDENTIAL**] [redacted] [**END CONFIDENTIAL**] in a given year, which is greater than the annual SSR.

[25] Note that Total Assets and Total Liabilities and Shareholders' Equity must always be equal.

Q. DOES MR. JACKSON'S FINANCIAL ANALYSIS, ON WHICH PROF. CHAMBERS'S PRO FORMA ANALYSIS IS BASED, INCORPORATE ANY OF THE IDENTIFIED REDUCTIONS IN CAPEX OR O&M EXPENSES?

A. No. As a result, neither Mr. Jackson's Exhibits CLJ-2 through CLJ-4, nor Prof. Chambers's pro forma analysis has any probative value. Moreover, neither Mr. Jackson nor Prof. Chambers prepared any financial analysis assuming DP&L structurally separates its competitive generation business from its regulated T&D business by December 31, 2014. Such structural separation would obviate the need for any SSR because, as Mr. Jackson stated in his deposition, DP&L's T&D revenues are adequate to provide safe and reliable service.

Q. DO MR. JACKSON'S FINANCIAL PROJECTIONS INCLUDE ADDITIONAL REVENUES AND PROFITS DP&L COULD EARN BY BIDDING INTO OTHER UTILITIES' SSO AUCTIONS?

A. No. In his deposition, Mr. Jackson admitted his financial projections did not include any impacts from bidding into other utilities' SSO auctions.

> Q. Do you know if potentially bidding into auctions of other utilities is modeled into your financial projections?
> A. No, it is not included or modeled in the projections.
> Q. I'm sorry, I didn't understand that answer. Did you say it was not modeled in the financial projections or did you say it's not included?
> A. It's not included in the projections.[26]

This omission is yet another flawed aspect of DP&L's financial projections and justification for the SSR. [27]

[26] Jackson Deposition, 2/15/2013, p. 158.

Q. HAVE YOU IDENTIFIED ANY OTHER ASSUMPTIONS IN MR. JACKSON'S FINANCIAL PROJECTIONS THAT RAISE CONCERNS?

A. Yes. Mr. Jackson explained in his deposition that the wholesale revenues reflected on line 4 of his Exhibit CLJ-2 include margin from sales to DPLER, calculated as the PJM LMP minus DP&L's embedded cost of fuel.[28] In effect, Mr. Jackson has assumed that DPLER will pay the hourly day-ahead price to DP&L for all energy DPLER is projected to purchase from DP&L during the ESP period and that this is the only margin DP&L will receive from sales to DPLER. If DP&L were properly structurally corporately separated and operating to maximize its revenues, independently of DPLER's interest in generating higher margins on its retail sales, DP&L would likely require a structure with a price higher than the LMP from whomever it would sell to. By assuming that DPLER will pay no more than the PJM LMP, Mr. Jackson has transferred the profit margin on these sales from DP&L to DPLER. In effect, the combined DP&L and DPLER balanced supply and demand portfolio results in foregone margins by DP&L and reduced costs and increased margins for DPLER. As a result, Mr. Jackson's wholesale revenue forecast for DP&L is understated and his (and Prof. Chambers's) claims of DP&L's loss of "financial integrity" exaggerated.

(cont.)

[27] While potential revenue from other auctions should be included in DP&L's projections, for many of the same reasons that DP&L or its affiliates should be prevented from bidding into DP&L's own SSO auction, if DP&L is granted the SSR it would be improper to allow it or its affiliates to bid into the SSO auctions of other Ohio utilities for the duration of the generation subsidy.

[28] Jackson Deposition, 2/15/2013, p. 169-75.

C. DP&L Does Not Show How or to What Extent the SSR Would Promote Stable Service.

Q. DOES DP&L PRESENT ANY OTHER ARGUMENTS AS TO WHY IT REQUIRES THE SSR?

A. Yes. In its response to interrogatory OCC-439 (attached as Exhibit JAL-8), DP&L argues the SSR is needed because only by maintaining the company's "financial integrity" can it provide "stable service."

Q. HOW DOES DP&L DEFINE STABLE SERVICE?

A. OCC-439(a) specifically asks, "What is the definition of stabilized service" as the term is used in the tariff?" DP&L witness Parke responds that financial integrity provides "stable service." However, as stated in its response to OCC-439(b), "DP&L does not propose any specific measure of stable service in connection with the SSR."

In his deposition, Mr. Jackson conflates "financial integrity," "adequate service," and "safe and reliable" service.[29] Thus, he argues that, but for the SSR payments, DP&L would have to "identify other areas where you would have to make up that SSR amount, which could have a detrimental impact on the system, on your – the system to serve your customers."[30] However, Mr. Jackson's statement is belied by the capex and O&M savings DP&L has identified. Moreover, DP&L does not propose to reduce its distribution service capex and O&M expenditures. Nor does Mr. Jackson ever identify any specific "detrimental impacts" that he alleges would jeopardize "safe and reliable" service.

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[29] *Id.*, pp. 93-94.

[30] *Id.*, p. 94.

As I discuss in the next section, DP&L witness Chambers never provides a definition of “financial integrity,” other than to assert it involves “many factors,” before defining “financial integrity” as DP&L’s ability to avoid a credit downgrade. Thus, DP&L asserts that its undefined ability to maintain “stable service” is contingent upon maintaining its similarly undefined “financial integrity,” all of which apparently are contingent upon DP&L’s receipt of at least $687.5 million in ratepayer subsidies through the SSR over the next five years.

Q. DOES MR. JACKSON TESTIFY THAT THE $138 MILLION SSR IS NEEDED FOR DP&L TO PROVIDE ADEQUATE SERVICE?

A. No. In his deposition, Mr. Jackson was asked that question.

> 4 Q. But in terms of the amount required to
> 5 provide adequate service, you can't tell me that to
> 6 provide adequate service in 2013 that you need
> 7 that -- exactly $137.5 million, correct?
> 8 A. Correct.[31]

Thus, Mr. Jackson cannot state whether the $138 million SSR payment is required to maintain adequate service. Furthermore, based on his previously referenced statement that transmission and distribution revenues are adequate over the ESP period, Mr. Jackson effectively admits that any inability to provide “adequate service” stems from DP&L’s competitive generating assets earning insufficient profits. The easiest and most straightforward solution to this “problem” is full structural separation because, as a

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[31] Jackson Deposition, 2/15/2013, p. 96.

regulated distribution utility, Mr. Jackson admits DP&L will obtain sufficient revenues to provide adequate service.[32]

D. The Arguments Made by DP&L Witness Chambers Regarding the Need for the SSR to Maintain DP&L's Financial Integrity Suffer From Fundamental Theoretical and Analytical Flaws.

Q. HOW DOES PROFESSOR CHAMBERS DEFINE "FINANCIAL INTEGRITY"?

A. According to Prof. Chambers:

> There is no single, simple definition because financial integrity has many different dimensions. For a firm like DP&L to have strong financial integrity it must have a solid business as well as a sound financial position. It must be able to operate its business efficiently, by means of having qualified management, capable personnel and adequate infrastructure. It must have the financial means to meet its obligations in a timely manner and to be able to invest to maintain its infrastructure and develop new infrastructure for the future. It must be sufficiently flexible to address changing conditions and to respond to those changes. A company's financial integrity also must be assessed in the context of the risks and uncertainties associated with the company's own performance, looking forward, not just backward, within the framework of the regional, national and international economies.[33]

Furthermore, Prof. Chambers states that, "the determination of financial integrity involves balancing these many factors."[34]

Q. DOES PROFESSOR CHAMBERS EVALUATE ALL OF THESE ASPECTS OF FINANCIAL INTEGRITY?

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[32] *Id.*, pp. 100 – 101.

[33] Chambers Direct, p. 9, lines 2-12 (emphasis added).

[34] DP&L's response to OCC Interrogatory INT-223 (attached as Exhibit JAL-9).

A. No, he does not.

Q. WHAT FACTORS DOES HE IGNORE?

A. Prof. Chambers ignores almost all of the factors he mentions. He uses only creditworthiness and corporate credit ratings to assess DP&L's financial integrity.[35] Prof. Chambers then constructs a "straw man" pro forma analysis that purports to demonstrate DP&L cannot maintain its creditworthiness without the SSR and the Switching Tracker. Prof. Chambers does not evaluate whether DP&L can operate its business efficiently with qualified management, capable personnel, and adequate infrastructure. Prof. Chambers does not evaluate DP&L's "flexibility" and ability to respond to changing conditions. For his analysis, Prof. Chambers ignores these factors entirely and focuses exclusively on a flawed projection of DP&L's overall earnings.

Q. CAN YOU EXPLAIN WHAT IS MEANT BY A "PRO FORMA" ANALYSIS?

A. Yes. A "pro forma" analysis is a projection of a firm's financial performance that builds on its historic positions. Evaluating a firm's financial performance and its value typically begins with projection of future revenues and costs, which determine profitability (typically measured by net income), and continues with an evaluation of the firm's overall balance sheet (i.e., its assets, liabilities, and capital structure).

Q. IS PROFESSOR CHAMBERS'S DEFINITION OF "FINANCIAL INTEGRITY" THE SAME AS THAT USED BY THE U.S. SUPREME COURT IN *HOPE NATURAL GAS*?

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[35] *Id*., p. 9, lines 15-21.

A. No. Again, despite his statements that financial integrity encompasses multiple dimensions, Prof. Chambers evaluates financial integrity solely in terms of credit ratings, arguing that, but for the SSR, DP&L will suffer a credit rating downgrade in the future. In *Hope Natural Gas*, the Court used a broader definition, specifically that a company be able to "maintain its credit and to attract capital."[36] A ratings downgrade, by itself, does not mean a company is unable to maintain its credit or attract capital. A ratings downgrade may mean a company's cost of capital increases. However, having to pay a higher cost of capital is clearly different than an inability to attract capital at any cost.

Q. CAN YOU SUMMARIZE THE ARGUMENTS MADE BY DP&L WITNESS CHAMBERS TO JUSTIFY THE $138 MILLION NONBYPASSABLE SSR AND THE NONBYPASSABLE SWITCHING TRACKER?

A. Yes. First, Prof. Chambers attempts to justify the SSR by relying on the Commission's decision regarding the AEP Ohio ESP, specifically the Commission's determination that AEP Ohio should be allowed to earn a return on equity ("ROE") of between 7% and 11%.[37] Prof. Chambers thus implicitly argues that a ROE range of between 7% and 11% will maintain DP&L's financial integrity. I refer to this as his "me, too" argument.

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[36] 320 U.S. 591, 603.

[37] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan*, Direct testimony of William Chambers, October 5, 2012 ("Chambers Direct"), p. 2, lines 12-14, citing *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the Form of an Electric Security Plan*, Case No. 11-346-EL-SSO et al., Opinion and Order, August 8, 2012, p. 33.

Second, Prof. Chambers relies on Mr. Jackson's financial projections, without accounting for the capex reductions discussed in DP&L's Impairment Analysis White Paper and O&M expense reductions identified by Mr. Jackson.

Finally, Prof. Chambers never evaluates DP&L's financial integrity using a pro forma analysis assuming the company's generating assets are structurally separated, despite structural separation being the cleanest, least-cost approach to guarantee the "financial integrity" of DP&L's regulated T&D operations.

Q. WHAT IS THE RELEVANCE OF DP&L WITNESS CHAMBERS'S REFERENCE TO THE PUCO'S DECISION IN THE AEP OHIO ESP PROCEEDING?

A. The PUCO's decision was dependent upon AEP Ohio's status as a Fixed Resource Requirement ("FRR") entity under PJM's rules.[38] As an FRR entity, AEP Ohio is responsible through May 31, 2015 for providing all of the installed capacity reserves for its connected retail load (both SSO customers and customers who purchase retail electricity from CRES providers). In contrast, by its own admission, DP&L has treated its generation as a competitive operation for the last decade. DP&L is not a FRR entity and instead participates in the PJM capacity market. Prof. Chambers's "me, too" comparison of a range of return on equity values for AEP Ohio with DP&L fails to account for this fundamental structural difference. Moreover, in his deposition, Prof. Chambers stated that he has no understanding of the FRR option and its significance.[39]

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[38] *See* PJM Reliability Assurance Agreement, Schedule 8.1.B and Schedule 8.1(D)(8). AEP Ohio has announced its intent to structurally separate generating resources effective January 1, 2014.

[39] Chambers Deposition, 2/12/2013, p. 45, lines 16-17.

More fundamentally, Prof. Chambers never demonstrates that DP&L's business and financial risk are comparable to AEP Ohio's, even though such "comparability" underlies the U.S. Supreme Court's *Hope Natural Gas* decision that Prof. Chambers cites to as justifying the SSR.

Q. DOES PROFESSOR CHAMBERS EVALUATE DP&L'S FINANCIAL INTEGRITY AND DETERMINE A $138 MILLION SSR IS THE MINIMUM AMOUNT NEEDED TO PRESERVE DP&L'S FINANCIAL INTEGRITY?

A. No. In response to Interrogatory FES-8-27 (attached as Exhibit JAL-10), which states that it was prepared by Prof. Chambers, DP&L provides an entirely circular response. Specifically, the response states the then-requested $120 million annual SSR is needed to preserve DP&L's financial integrity "as explained in the testimony of William Chambers." In response to Interrogatory OCC 13-224 (attached as Exhibit JAL-11), DP&L states witness Craig Jackson "led the effort to determine the amount of the SSR."

Q. DOES DP&L WITNESS JACKSON'S TESTIMONY DISCUSS HOW THE $138 MILLION SSR WAS DETERMINED ANALYTICALLY?

A. No. Mr. Jackson's testimony states, "The amount and duration of the service stability rider is critical for the Company to maintain its financial integrity and to have the opportunity to earn a reasonable rate of return as described by Company Witness Chambers' testimony in this case."[40] Nowhere in Mr. Jackson's testimony is there an explanation of why the specific SSR value is the minimum amount DP&L requires to maintain the company's "financial integrity." Indeed, when challenged on this point in

[40] Jackson Direct, p. 5, lines 19-21.

his deposition, even Mr. Jackson could not explain how the $138 million SSR value was calculated.

> 16 Q. Is the SSR of $137.5 million that's
> 17 requested for 2013, is that a dollar-for-dollar
> 18 equivalent of the adjustments that you describe would
> 19 have to be made in order to ensure that adequate
> 20 service is provided?
> 21 A. The $137-1/2 million SSR is the amount
> 22 that we believe is needed to maintain our financial
> 23 integrity.
> 24 Q. So the answer is no, it's not a
> 1 dollar-for-dollar comparison?
> 2 A. The answer is it's the amount that we
> 3 need to maintain our financial integrity.
> 4 Q. But in terms of the amount required to
> 5 provide adequate service, you can't tell me that to
> 6 provide adequate service in 2013 that you need
> 7 that -- exactly $137.5 million, correct?
> 8 A. Correct.[41]

Q. CAN YOU SUMMARIZE THE ANALYTICAL FLAWS IN DP&L WITNESS CHAMBERS'S PRO FORMA ANALYSIS?

A. Yes. Prof. Chambers's analysis is fundamentally flawed because he bases his entire analysis of DP&L's financial integrity on an assumption that DP&L remains a <u>vertically integrated</u> utility at the mercy of market forces. This is untrue given DP&L's current functional separation of its generating assets and treatment of those assets as "competitive."

If DP&L structurally separates its generation assets into an unregulated subsidiary that competes in the market, then DP&L will be a local distribution ("poles and wires")

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[41] Jackson Deposition, 2/15/2013, p. 95-96.

utility. The company will provide nonbypassable delivery service, charging regulated distribution rates and earning a regulated return on its assets.

What DP&L is really asking is that all of its customers be forced to pay the company at least an additional $687.5 million in above-market returns, despite having been through restructuring almost a decade ago, and despite having been compensated for the costs of additional generation investment under the current Revenue Stability Charge ("RSC"). DP&L will then use these monies to enable it to increase the market value of its competitive generating assets before structural separation. The SSR allows DP&L to maintain profit margins on competitive market generation sales that DP&L itself admits are unsustainable in a competitive market. Prof. Chambers recognizes the obvious by referencing a discussion by Standard & Poor's of lower profit margins ***because of increased competition***.[42] Because increased competition, by definition, will not affect DP&L's fully regulated T&D services, the lower profit margins referenced by Standard & Poor's can refer only to DP&L's competitive generation assets.

The fact that DP&L's profit margins in the competitive retail and wholesale generation markets may be lower than DP&L's current monopoly service does not entitle DP&L to recover "lost" profits, even if doing so were needed to maintain the company's "financial integrity." This is especially true because DP&L received over $400 million in compensation in the years 2002 – 2004 during the transition to competition,[43] and because the company has treated its generating assets as a competitive business unit since 2003.

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[42] Chambers Direct, p. 27, lines 2-8.

[43] In its responses to OCC-407 and OCC-408, DP&L stated that information of customer and regulatory transition charges collected before 2002 are not available.

Competitive retail and wholesale generation markets promote greater economic efficiency and lower costs for consumers. Competitive markets reward suppliers who increase their operating efficiency and reduce their costs with higher profit margins. Rather than improving its efficiency, however, DP&L wishes its functionally separated generation to be subsidized by all DP&L ratepayers for the next five years.

Q. IS DP&L'S "FINANCIAL INTEGRITY" AFFECTED BY ITS COSTS, AS WELL AS REVENUES?

A. Absolutely. The projections of DP&L's annual return on equity shown on line 45 of Exhibit CLJ-2 are clearly affected by DP&L's generation, transmission, and distribution costs.

Q. DID DP&L WITNESS JACKSON EVALUATE POTENTIAL COST SAVINGS DP&L COULD UNDERTAKE, WHICH WOULD THEN AFFECT THE PRO FORMA ANALYSIS PREPARED BY PROF. CHAMBERS?

A. No. Although, as I discussed above, in his deposition Mr. Jackson acknowledged both capex and O&M cost savings, his Exhibit CLJ-2 does not reflect any of these potential capex and O&M cost savings. The projected costs DP&L developed for purposes of its ESP filing, which exclude any potential savings, are what were used by Prof. Chambers. Thus, not only does Prof. Chambers's pro forma analysis <u>not</u> incorporate the capex and O&M reductions identified by DP&L witness Jackson, it includes additional depreciation expenses that would not be paid, and additional property taxes that would not be paid, if capex was reduced.

Q. DID DP&L PERFORM ANY EVALUATION OF POTENTIAL COST SAVINGS?

A. Yes. According to its response to Interrogatory IEU 3-1 and its subparts (attached as Exhibit JAL-12), DP&L states it has studied potential cost reductions and revenue enhancements. Both would conceivably affect the financial integrity analysis prepared by Prof. Chambers. In fact, DP&L has identified both capex reductions and O&M expense reductions.

Q. ARE ANY OF THESE POTENTIAL COST SAVINGS REFLECTED IN THE PRO FORMA ANALYSIS PREPARED BY PROFESSOR CHAMBERS?

A. No.

Q. WOULD INCORPORATING COST SAVINGS AFFECT PROFESSOR CHAMBERS'S PRO FORMA ANALYSIS?

A. Yes. If one reduced capex and, hence, depreciation expense, and reduced O&M expense, net income would increase as would "Cash and cash equivalents." This would not only increase DP&L's net income, but also increase common shareholders' equity and allow for greater dividend payments to DP&L's parent, DPL Inc.

Q. IS THE SSR THE "LEAST-COST" APPROACH TO MAINTAINING DP&L'S FINANCIAL INTEGRITY?

A. No. DP&L's demand for a $687.5 million SSR subsidy, plus additional subsidies through a switching tracker, is not the least-cost approach to addressing the company's claimed financial integrity problem, which stems from its competitive generation business.

If DP&L's financial integrity is at issue, the PUCO should determine the least-cost strategy to maintain the financial integrity of DP&L's franchised local distribution function. Such a "least-cost" strategy should start with the capex and O&M cost reductions DP&L already has identified, and end with structural separation of DP&L's competitive generation assets sooner rather than later. DP&L has not demonstrated why a $687.5 million subsidy, plus additional subsidies through a switching tracker, is a better option for DP&L ratepayers than implementing the cost reductions it has already identified, followed by corporate separation on December 31, 2014.

Q. DID PROFESSOR CHAMBERS CONSIDER THIS LEAST-COST APPROACH?

No. Prof. Chambers did not perform any pro forma analysis assuming DP&L's generating assets have been structurally separated. This is a crucial omission because, as Prof. Chambers testifies, the key drivers of DP&L's financial risk stem from the revenues and costs of its generating assets, including volatility in fuel costs, environmental regulations and emission allowance prices, and operational problems with DP&L's facilities.[44] Of course, DP&L's regulated operations are always at risk if it makes investments or engages in activity that the PUCO finds to be imprudent. Nevertheless, as a standalone "poles and wires" business, the risks faced by DP&L are far less, because they do not involve risks associated with wholesale and retail competition. Yet, in evaluating the financial integrity of DP&L, Prof. Chambers never considers how structural separation of the company's generation assets would provide far greater financial protection for DP&L's regulated T&D activities and not require DP&L customers to subsidize its generating assets.

Q. WHY IS THIS IMPORTANT?

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[44] Chambers Direct, p. 26, lines 4-10. These risks are described on pp. 24-26 of DPL, Inc.'s 2011 Form 10-K.

A. As a fully regulated poles and wires company, DP&L's financial integrity would not be jeopardized. The poles and wires company would operate under traditional regulatory principles and be granted a risk-comparable return by the PUCO.

As DP&L itself has testified, it earns lower margins on competitive market generation sales than through regulated sales. Thus, it is not the company's regulated poles and wires operations that are driving the forecasts of lower overall returns. Rather, it is the company's generating assets.

Because the generating assets by DP&L's own admission have operated in a competitive market since the end of the transition period on December 31, 2003, DP&L is not entitled to earn above-market returns on that generation through ratepayer subsidies, such as the SSR and Switching Tracker. Yet that is precisely what DP&L requests, in the amount of at least $687.5 million for the SSR alone.

By separating out the competitive generation from the regulated T&D functions of the company, a far more accurate picture would emerge of whether the financial integrity of the regulated T&D operations somehow would be jeopardized during the five-year ESP. Instead, by creating an artificial pro forma analysis, Prof. Chambers has prepared a biased assessment of DP&L's financial integrity, because he assumes that market-based returns on DP&L's generating assets will impair its T&D operations. Structural separation addresses that possibility in a clear and straightforward manner.

Q. IS DP&L'S GENERATION UNREGULATED?

A. Yes. According to the response to IEU INT 1-8 (attached as Exhibit JAL-13), DP&L's generation business unit was fully merchant at the end of the three-year transition period that ended on December 31, 2003. Thus, this business unit has now operated competitively for over nine years. Furthermore, DP&L states it discontinued regulatory accounting for its generation function in September 2000.

Q. WHY DOES THE FACT THAT DP&L'S GENERATION BUSINESS HAS BEEN A COMPETITIVE ACTIVITY FOR A DECADE MATTER IN THIS PROCEEDING?

A. It matters for at least four reasons. First, one of DP&L's justifications for the SSR and the Switching Tracker is the lower profit margins on its generation sales because of increased retail competition. This is an admission that DP&L is less able to earn above-market returns on its unregulated generation assets because of competition.

Second, DP&L admits the SSR may compensate its competitive generation business.[45] Thus, DP&L is admitting ratepayers should be forced to subsidize its competitive generation business. There is no economic rationale for DP&L to be entitled to earn above-market returns on its generating assets through coerced subsidies from all of its customers, including customers who have switched to CRES providers.

Third, DP&L ignores the relationship to its retail affiliate, DPLER. In 2011 DPLER, which purchases all of its generation from DP&L, accounted for approximately 5,731 million kWh of the total 6,593 million kWh – 87% – of total sales by CRES providers in its service territory.[46] Because its own affiliate is capturing 87% of all CRES sales in its service territory, DP&L is effectively asking for $687.5 million in SSR revenues, plus a Switching Tracker, to ensure it can earn an above-market return on its competitive generation assets. DP&L sells that generation to its retail affiliate, which

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[45] *See* Response to IEU Interrogatory 1-39, attached as Exhibit JAL-14.

[46] *See* Response to IEU RFA 1-10, attached as Exhibit JAL-3.

supplies almost all of the competitively purchased electricity in DP&L's service territory. By forcing all DP&L ratepayers to subsidize its competitive generation activities through the SSR, DP&L has far greater opportunities to cross-subsidize its retail affiliate and ensure the retail affiliate "beats" competing CRES providers in DP&L's service territory.

Fourth, the nonbypassable SSR, Switching Tracker, and AER will all raise the cost of switching by forcing customers who switch to pay unjustified nonbypassable charges and thus reduce the incentive for customers to shop in DP&L's service territory, further enhancing DP&L's financial position.

Q. DO YOU HAVE ANY OTHER CRITICISMS OF DP&L WITNESS CHAMBERS'S PRO FORMA ANALYSIS?

A. Yes. Prof. Chambers's entire analysis is what I would term a "bootstrap" analysis of DP&L's financial integrity. By "bootstrap" analysis, I mean the following. Prof. Chambers defines DP&L's "financial integrity" as its overall creditworthiness, ignoring all other aspects that he himself discusses as components of "financial integrity."[47] He then concludes DP&L faces significant financial risks that can only be addressed with $687.50 million in SSR payments, plus additional revenues from the Switching Tracker, based on his narrow definition of financial integrity.

III. DP&L'S PROPOSED NONBYPASSABLE ALTERNATIVE ENERGY RIDER ("AER-N") IS ANTICOMPETITIVE

Q. CAN YOU SUMMARIZE WHY THE PROPOSED NONBYPASSABLE ALTERNATIVE ENERGY RIDER, EVEN AS A PLACEHOLDER, IS ANTICOMPETITIVE?

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[47] Chambers Direct, p. 9, lines 12-13.

A. Yes. DP&L proposes to include the costs of its Yankee Solar facility in the AER-N.[48] If it is allowed to do so, it effectively forces customers who purchase their electricity from CRES providers to pay twice for renewable energy required under Ohio's renewable portfolio standard ("RPS") requirements. The reason is that CRES providers must meet the renewable energy requirements under R.C. 4928.64(B). Thus, a customer taking service from a CRES provider pays for the solar Renewable Energy Credits ("SRECs") obtained by its CRES provider.

Under DP&L's proposed nonbypassable AER-N, customers taking service from CRES providers would also be forced to pay for the Yankee Solar facility if the PUCO approved DP&L's recovering the costs of that facility through the proposed nonbypassable AER-N. For example, 99% of all DP&L industrial load is served by CRES providers.[49] Thus, under DP&L's proposed nonbypassable AER-N, virtually every industrial customer in DP&L's service territory would be forced to pay higher costs for electricity by virtue of DP&L's collecting the costs of the Yankee Solar facility through a nonbypassable AER-N.

Q. IS DP&L REQUESTING THE PROPOSED NONBYPASSABLE RIDER FOR OTHER SOLAR FACILITIES BESIDES YANKEE SOLAR?

A. There is no discussion of other solar facilities in DP&L's testimony. Nor, as I discuss below, given DP&L's own customer switching forecast and the amount of solar

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[48] Seger-Lawson Direct, p. 16, lines 6-10.

[49] *See* Workpapers 8A and 8B, sponsored by DP&L witness Hoekstra. Hoekstra Direct, p. 3, lines 4-9.

photovoltaic ("PV") developed in Ohio, will DP&L need to acquire additional solar PV to meet Ohio's SREC requirements under R.C. 4928.64(B)(2).

Q. DP&L WITNESS SEGER-LAWSON TESTIFIES THAT THE PUCO DETERMINED THERE WAS A "NEED" FOR YANKEE SOLAR. WHAT IS THAT "NEED" BASED ON?

A. Ms. Seger-Lawson cites to language in a Stipulation approved by the PUCO almost two years ago as part of DP&L's 2010 Long-Term Forecast Report ("LFTR"), which was filed in April 2010.[50] Specifically, Ms. Seger-Lawson quotes language referring to the first phase of the Yankee Solar facility, called Yankee Solar 1.[51] The PUCO found there was a need for a 1.1 MW facility, known as Yankee Solar 1. It did not find that market deficiencies required DP&L to construct Yankee Solar 1 and obtain nonbypassable cost recovery pursuant to R.C. § 4928.143(B)(2)(c). Nor has DP&L ever demonstrated that Yankee Solar was the least-cost solar alternative available.

Q. WAS FES A PARTY TO THE STIPULATION APPROVED BY THE PUCO?

A. No. The Signatory Parties to the Stipulation, which was filed with the PUCO on January 14, 2011, were DP&L, the Office of the Ohio Consumers' Counsel ("OCC"), the Ohio Environmental Council ("OEC") and the PUCO Staff.[52] OCC did not stipulate that there was a need for the Yankee Solar facility under R.C. § 4928.143(B)(2)(b) or (c).

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[50] A copy of the April 19, 2011 Order approving the Stipulation in Case No. 10-505-EL-FOR is attached as Exhibit JAL-15. Ms. Seger-Lawson's testimony erroneously states the PUCO order was issued on April 14, 2010. DP&L filed its 2010 LTFR on April 15, 2010.

[51] Seger-Lawson Direct, p. 16, lines 4-5.

[52] *See* Exhibit JAL-15.

Q. DID THE 2010 LTFR PROPOSE BUILDING ADDITIONAL SOLAR PV FACILITIES?

A. Yes. Page 4 of the "Resource Plan" included with the 2010 LTFR, states "DP&L is tentatively planning a second phase of the Yankee Solar Generating Facility (or another site if space is not adequate) that will add an additional 1.2 MW of solar generation. This second phase of the project could be operational as early as December 31, 2010. DP&L will request rate recovery for the Yankee solar facility through a separate filing with the PUCO."

Q. DID THE 2010 LTFR PROVIDE ANY JUSTIFICATION FOR DP&L CONSTRUCTING THE YANKEE SOLAR FACILITY?

A. Yes. On page 27 of the Electric Distribution Forecast portion of the 2010 LTFR, DP&L stated, "There is currently very little Ohio-certified solar generation in Ohio; therefore, the Yankee Solar project will provide a firm, cost-effective source, as well as a hedge against the cost of RECs, which may subsequently become available."

Q. DID DP&L CONSTRUCT THIS SECOND PHASE OF YANKEE SOLAR?

A. No. As stated in Item 3 of the filed Stipulation:

> As filed in its April 15 LTFR filing, DP&L proposed a second solar facility of the approximate same size as Yankee 1 such that the Company's Renewable Resources available in 2011 would be 2.3 MW as shown on Form FE-R6. From the time of the April 15, 2010 LTFR filing to the date of this Stipulation, changing market conditions, and sales to standard offer customers, among other factors, have presented the Company with an ability to delay the construction of the second solar facility.

Q. WHAT "CHANGING MARKET CONDITIONS" AND "SALES TO STANDARD OFFER CUSTOMERS" WOULD AFFECT THE "NEED" FOR A SECOND PHASE OF YANKEE SOLAR?

A. Changing market conditions include: (1) reductions in DP&L's overall energy sales forecast reduce its solar REC ("SREC") requirement; (2) Reductions in SSO sales because of higher than anticipated switching by customers to CRES providers; and (3) additional development of in-state solar generating resources.

A. DP&L's Sales Forecast Has Decreased Significantly Since Filing Its 2010 LTFR

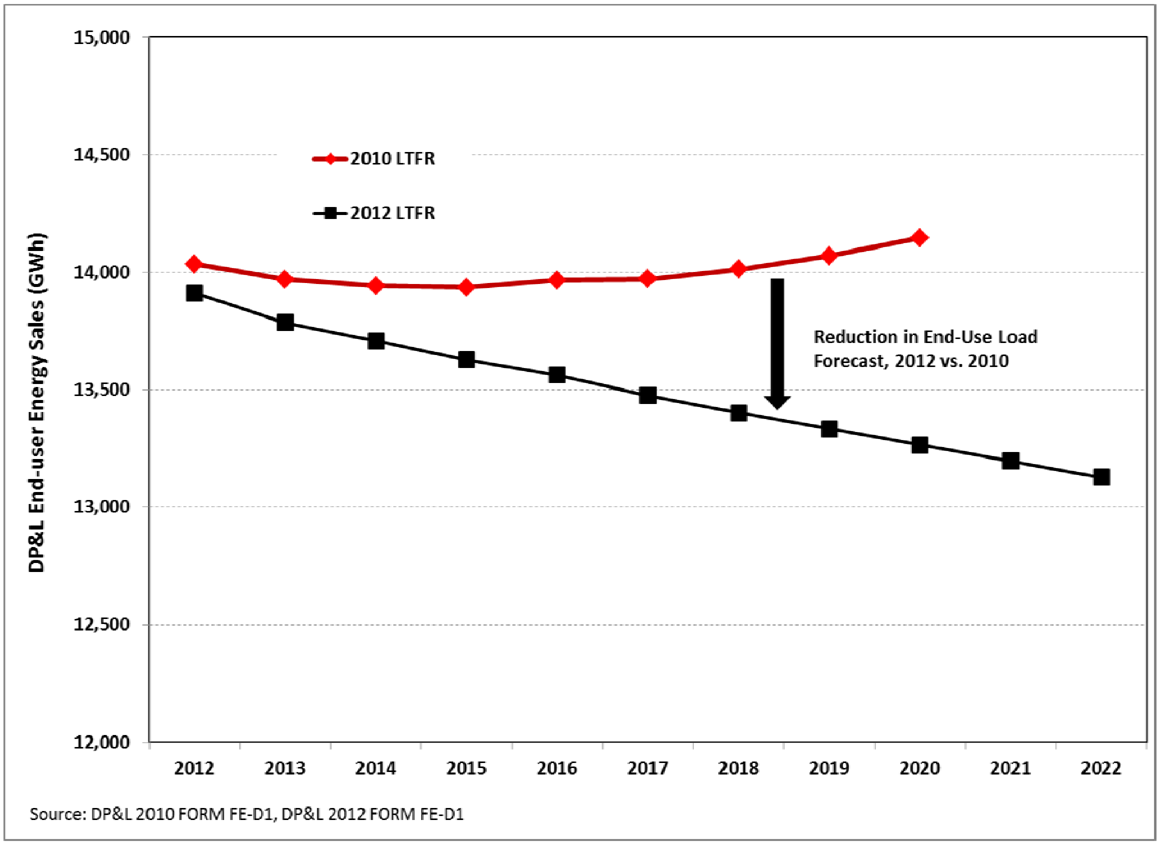
Q. DID DP&L PROVIDE A FORECAST OF SWITCHING LOAD IN ITS 2010 LTFR?

A. No. The 2010 LTFR filed by DP&L on April 15, 2010 does not include any forecast of switching load. The 2010 LTFR included DP&L's forecast of total energy consumption for the years 2010 – 2020 (Form FE-D1) (attached as Exhibit JAL-16), but not actual SSO consumption.

Q. HAS DP&L'S ENERGY SERVICE CONSUMPTION FORECAST CHANGED SINCE IT FILED ITS 2010 LTFR?

A. Yes. DP&L filed its 2012 LTFR on April 13, 2012. In that filing, FORM FE-D1 shows a significant decrease in DP&L's total end user consumption. Figure 1 provides a comparison of the two forecasts.

Figure 1: DP&L 2010 LTFR and 2012 LTFR End-Use Consumption Forecasts



As Figure 1 clearly shows, DP&L's own forecast of total end-use electric consumption has declined substantially since it filed its 2010 LTFR.

Q. IS THE 2013 ENERGY SALES FORECAST SPONSORED BY DP&L WITNESS HOEKSTRA CONSISTENT WITH THE 2010 LTFR FORECAST?

A. No. According to DP&L witness Hoekstra,[53] the 2013 baseline sales volumes are actually the calendar year 2011 weather-normalized sales volumes. Thus, in this proceeding, DP&L relies on its outdated 2010 LTFR to justify the "need" for Yankee Solar and, hence, a nonbypassable AER-N, despite having filed a significantly lower total

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[53] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan,* Second Revised Direct testimony of Aldyn Hoekstra, December 12, 2012 ("Hoekstra Direct"), p. 4, lines 8-9.

end-use sales forecast in its 2012 LTFR, and uses weather-normalized calendar year 2011 sales as the basis for its revenue projections and blended SSO rates, and the projections of Switching Tracker revenues shown in Exhibit CLJ-5.

Q. DOES THE REDUCTION IN DP&L'S OVERALL END-USE SALES FORECAST AFFECT DP&L'S SOLAR PV REQUIREMENT UNDER R.C. 4928.64(B)(2)?

A. Yes. Even before accounting for additional switching to CRES providers, the decrease in DP&L's overall sales forecast reflected in the 2012 LTFR compared with the 2010 LTFR means a reduced solar requirement.

B. DP&L Has Not Provided an Estimate of Its SSO-Load In-State Solar Requirement

Q. DOES ATTACHMENT 1 TO THE 2010 LTFR STIPULATION ESTIMATE DP&L'S IN-STATE SOLAR REQUIREMENT BASED ON THE COMPANY'S SSO LOAD?

A. No. Attachment 1 to the 2010 LTFR Stipulation calculates the in-state solar requirement based on DP&L's total SSO and CRES energy sales. That Attachment shows DP&L's total in-state SREC requirement to be 3,314 MWh in 2012. However, this forecast is based on DP&L's 2010 LTFR that, as shown previously in Figure 1, has dropped significantly.

Q. DID DP&L PROVIDE ANY ESTIMATE OF ITS IN-STATE SREC REQUIREMENT IN ITS MOST RECENT LTFR?

A. No. There is no discussion of renewable energy requirements whatsoever in DP&L's 2012 LTFR, nor has DP&L filed any supplements to the 2012 LTFR detailing those requirements.

Q. AS PART OF ITS SECOND REVISED ESP FILING, HAS DP&L CALCULATED ITS IN-STATE SREC REQUIREMENT OVER THE 2013 – 2018 PROPOSED ESP TIME FRAME?

A. No. The sole evidence provided by DP&L for the "need" for Yankee Solar and a nonbypassable AER-N is the PUCO's acceptance of the aforementioned 2010 LTFR Stipulation, which is based on an outdated and too high load forecast and fails to account for the over 60 MW of in-state solar PV resources approved by the PUCO since 2010[54] – evidence of the continuing development of markets for solar development in Ohio. As the Commission stated in PUCO Case No. 10-501-EL-FOR: "The record indicates that the number of in-state solar photovoltaic applications that have been approved by the Commission since 2009 has grown (FES Ex. 1 at 36-37), and there is no evidence that this trend will not continue."[55]

Q. HAVE YOU CALCULATED DP&L'S IN-STATE SREC REQUIREMENT FOR THE YEARS 2012-2020?

A. Yes. I have based my calculations on DP&L's 2012 LTFR filing and the retail switching levels used by DP&L in this ESP filing. These retail switching levels can be derived from workpapers WP-8a and WP-8b, which are supported by DP&L witness Hoekstra, by comparing the "Distribution Sales Baseline" (WP-8a) and the "SSO Sales Baseline" (WP-8b) data.

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[54] *See* http://www.puco.ohio.gov/puco/index.cfm/puco-forms/renewable-energy-resource-generating-facility-application-for-certification/ (accessed January 8, 2013). A total of 75 MW has been developed since 2009.

[55] *In the Matter of the Long-Term Forecast Report of Ohio Power Company and Related Matters*, Case No. 10-501-EL-FOR et al., Opinion & Order at p. 27 (Jan. 9, 2013).

The details of my calculation are shown in Table 2 below. I began my analysis with DP&L's 2012 LTFR forecast end-use sales, net of demand-side management ("DSM") and demand-response ("DR") energy savings. The values I show in column (1) of Table 2 are the same as those displayed in column (6) of DP&L's 2012 LTFR Form FE-D1.[56]

Because DP&L's in-state SREC requirement is based on SSO load, I next subtracted out shopping loads from total distribution metered consumption in column (1).

Table 2: Calculation of DP&L In-State SREC Requirement

Year	DP&L Total Distr. Meter Load (GWh)	DP&L Baseline Shopping Load Percentage	DP&L Assumed Shopping Load (GWh)	DP&L Net SSO Load (GWh)	DP&L SREC Obligation Basis (GWh)	In-State SREC Percentage	DP&L SSO In-State SREC Requirement (MWh)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
2012	13,912	61.70%	8,584	5,328	9,166	0.030%	2,750
2013	13,786	61.70%	8,506	5,280	6,860	0.045%	3,087
2014	13,708	61.70%	8,458	5,250	5,301	0.060%	3,180
2015	13,628	61.70%	8,408	5,220	5,286	0.075%	3,965
2016	13,562	61.70%	8,368	5,194	5,250	0.090%	4,725
2017	13,476	61.70%	8,315	5,161	5,221	0.110%	5,743
2018	13,402	61.70%	8,269	5,133	5,192	0.130%	6,749
2019	13,332	61.70%	8,226	5,106	5,163	0.150%	7,744
2020	13,264	61.70%	8,184	5,080	5,133	0.170%	8,727
2021	13,196	61.70%	8,142	5,054	5,106	0.190%	9,702
2022	13,128	61.70%	8,100	5,028	5,080	0.210%	10,668

Notes:
[1] Source: 2012 LTFR , FORM FE-D1 (net of DSM).
[2] Source: Hoekstra, WP-8, based on WP-8a and WP-8b data
[3] Equals [1] x [2].
[4] Equals [1] - [3].
[5] Equals average of three previous years' net SSO load.
[6] Source: R.C. 4928.64(B)(2), based on 50% of total SREC percentages.
[7] Equals [5] x [6].

Q. HOW DID YOU CALCULATE DP&L'S SHOPPING LOAD AND NET SSO LOAD?

[56] I have omitted historic sales data from Table 2.

A. I used the data from DP&L's WP-8a and WP-8b to calculate the overall average shopping load percentage and, as a conservatism, I assumed this shopping load percentage would remain constant over time, just as DP&L assumed constant shopping levels over the five-year ESP period. Workpaper WP-8a shows total weather-adjusted distribution sales for 2011, which DP&L uses as its 2013 baseline, of 13,822,395 MWh. Similarly, Workpaper WP-8b shows total SSO sales of 5,293,868.2 MWh. This reflects an average shopping percentage of 61.7% as of August 30, 2012.[57] Using this shopping percentage, the shopping load in each year shown in column (3) of Table 2, equals 61.7% of total metered sales in column (1), as shown in column (3). Subtracting this amount from column (1) yields the forecast of DP&L's SSO loads, as shown in column (4) of Table 2.

Q. HOW DID YOU CALCULATE DP&L'S SREC REQUIREMENT IN EACH YEAR?

A. DP&L's SREC requirement in each year is based on the average of the company's previous three year's SSO load, and the SREC percentages set forth in R.C. 4928.64(B)(2). To calculate DP&L's net SSO loads in the years 2009 – 2010, I used actual SSO sales data, as reported by DP&L in its Alternative Energy Compliance Filings. DP&L's 2011 Alternative Energy Compliance Filing does not report actual SSO sales in 2011. Therefore, I have relied on the weather-normalized SSO sales reported in DP&L Workpaper WP-8b.

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[57] Hoekstra Direct, p. 6, lines 6-11.

Q. DO YOU CONSIDER THE IN-STATE SREC REQUIREMENTS FOR DP&L YOU SHOW IN TABLE 1 TO BE CONSERVATIVE?

A. Yes. For my analysis, I assume, as DP&L does for its ESP, there is no additional switching to CRES providers after 2012. Because continued switching is likely to take place, DP&L's assumption is unrealistic. Indeed, DP&L witness Hoekstra projects that shopping will exceed 80% by the end of 2013 and exceed 88% by the end of 2015.[58] Nevertheless, assuming no additional switching provides a clear upper bound on DP&L's future in-state SREC requirements and is thus a conservative estimate with which to gauge the "need" for the SRECs provided by the Yankee Solar facility.

Q. HOW DO YOUR IN-STATE SREC ESTIMATES COMPARE WITH THE IN-STATE SREC REQUIREMENTS ESTIMATED BY DP&L IN ITS TEN YEAR ADVANCED ENERGY AND RENEWABLE ENERGY BENCHMARK COMPLIANCE PLAN FILED IN APRIL OF 2012?[59]

A. There are several differences. First, the DP&L Ten-Year Compliance Plan assumes no additional switching takes place after December 31, 2011. At the end of 2011, the reported overall average switching rate was 51.15%, as shown in the PUCO's Q4 2011 Market Monitoring Report. Thus, significant customer switching has taken place since December 31, 2011.

Second, the DP&L Ten-Year Compliance Plan assumes DP&L's three-year average SSO load forming the basis of the in-state SREC requirement remains constant at 6,755.7 MWh over the years 2014-2022. In contrast, DP&L's 2012 LTFR projects

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[58] Hoekstra Direct, p. 8, lines 1-3.

[59] *In the Matter of The Dayton Power and Light Company's Ten Year Advanced Energy and Renewable Energy Benchmark Compliance Plan*, Case No. 12-1204-EL-ACP, DP&L Ten Year Compliance Plan, April 13, 2012 ("DP&L Ten-Year Compliance Plan").

decreasing total distribution sales between 2012 and 2022. Coupled with a far higher observed switching rate, DP&L's in-state SREC obligation basis is far lower.

As a result of these two factors, the DP&L Ten-Year Compliance Plan significantly overstates DP&L's in-state SREC requirement, beginning in 2013.

Q. HAVE YOU ESTIMATED BY HOW MUCH DP&L HAS OVER-ESTIMATED ITS IN-STATE SREC REQUIREMENT?

A. Yes. Table 2 provides the amount of the overestimate of DP&L's in-state SREC requirement, both on a MWh and percentage basis.

Table 2: DP&L Overestimate of In-state SREC Requirement

Year	DP&L SSO In-State SREC Requirement (MWh)	DP&L Ten-Year Compliance Plan Reported In-State SREC Requirement (MWh)	Compliance Plan Excess in-State SREC Requirement (MWh)	Compliance Plan Excess in-State SREC Requirement (Percent)
	[1]	[2]	[3]	[4]
2012	2,750	2,896	146	5%
2013	3,087	3,520	433	14%
2014	3,180	4,053	873	27%
2015	3,965	5,067	1,102	28%
2016	4,725	6,080	1,355	29%
2017	5,743	7,431	1,688	29%
2018	6,749	8,782	2,033	30%
2019	7,744	10,133	2,389	31%
2020	8,727	11,485	2,758	32%
2021	9,702	12,836	3,134	32%
2022	10,668	14,187	3,519	33%

Notes:
[1] Source: Table 2.
[2] Source: DP&L Ten-Year Compliance Plan
[3] Equals: [2] - [1].
[4] Equals: { [2] / [1] } - 1.

As Table 2 shows, DP&L's Ten-Year Compliance Plan increasingly overestimates the company's in-state SREC requirement. In 2013, I calculate DP&L's overestimate to be 14%. By 2022, the overestimate increases to 33%. Because I have assumed that shopping will not exceed 61.7%, but shopping is likely to exceed this mark, it also is likely that DP&L's overestimates are even greater. Moreover, the 75 MW of in-state solar approved by the PUCO between 2009 and 2012, and the almost 95,000 MWh of in-state solar generation that capacity will produce, can provide DP&L with its in-state SREC requirements many times over, without Yankee Solar.

C. The Reasons DP&L Provided Underlying the "Need" for a Nonbypassable AER-N to Recover the Costs of its Yankee Solar Facility Are No Longer Valid

Q. HAVE YOU COMPARED DP&L'S IN-STATE SREC REQUIREMENTS WITH AVAILABLE SOLAR GENERATION SUPPLIES?

A. Yes. This comparison is important because, as I discussed previously, it was the basis for DP&L's stated "need" for the Yankee Solar facility, as set forth in its 2010 LTFR, Attachment 1 to the Stipulation, and the PUCO's approval of that Stipulation in April 2011.

Q. IS THERE STILL "VERY LITTLE" SOLAR GENERATION IN OHIO, AS DP&L STATED IN ITS 2010 LTFR?

A. No. According to data published by the PUCO, at the end of December 2012, almost 46 MW of solar photovoltaic resources have been approved by the PUCO for development in Ohio since 2009. Assuming an annual capacity factor of 13% for solar installation less than 1 MW and 14% for larger installations, these facilities will provide an estimated 94,700 MWh of in-state solar renewable energy credits.[60] Based on DP&L's 2012 LTFR filing and the retail switching values used by the company in this

[60] AEP Ohio claims the Wyandot Solar Energy Facility has an annual capacity factor of 17%.

ESP proceeding, the amount of in-state solar development that has already taken place exceeds DP&L's projected need for in-state solar resources in the year 2022 by almost 800%. Thus, the claimed "need" for Yankee Solar, which allegedly stemmed from a lack of in-state solar development, is demonstrably false.

Q. HAS THE PRICE OF IN-STATE SRECS DECREASED SINCE 2010?

A. Yes. According to the firm FLETT Exchange, which publishes daily prices for in-state 2012 SRECs in Ohio, prices decreased from a peak of $250/MWh in a March 2012 to $57.50/MWh in December 2012.[61] These prices are lower than the previous year, in which SREC prices ranged from a high of $365/MWh to a low of $100/MWh. These clearing prices for 2011 and 2012 Ohio in-state SRECs are shown in Figure 2, below.[62]

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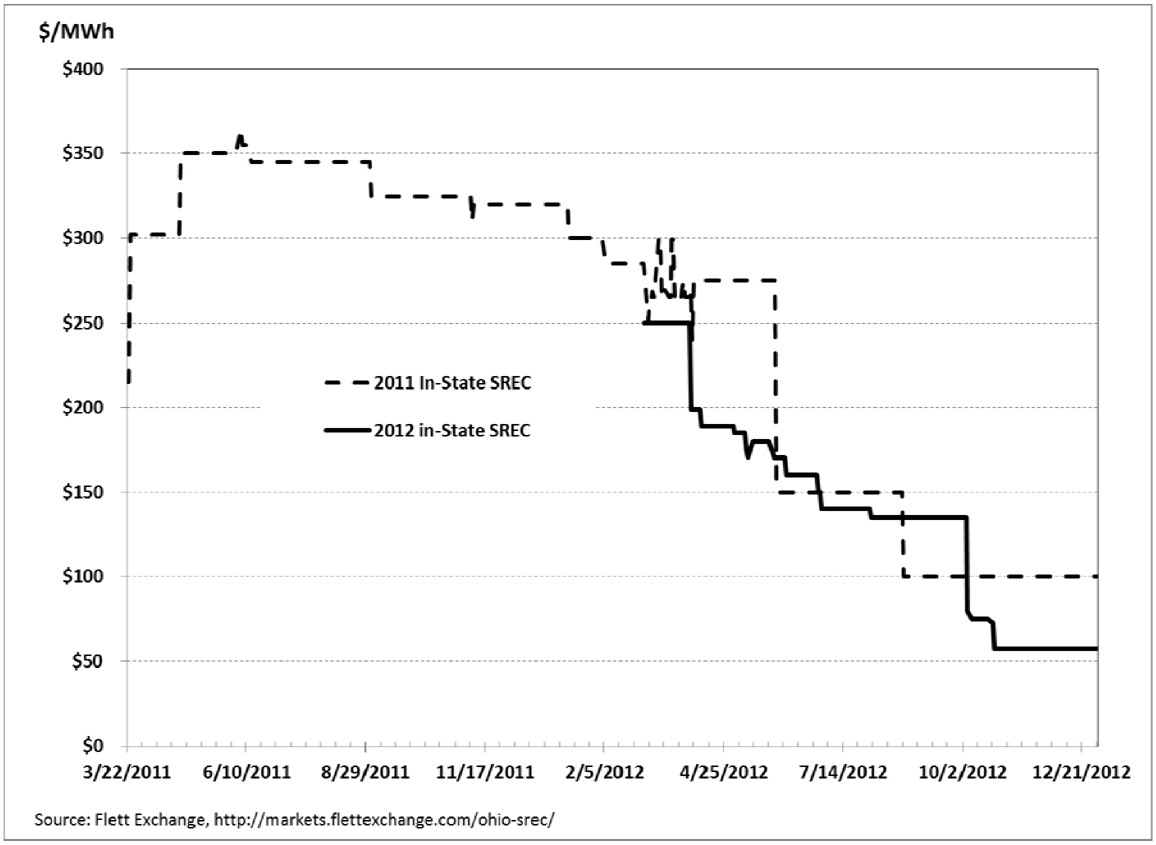
[61] Source: http://markets.flettexchange.com/ohio-srec/ (accessed January 2, 2013).

[62] Data through 12/31/2012.

Figure 2: Ohio 2011 and 2012 Daily In-State SREC Clearing Prices



As Figure 2 shows, 2012 in-state SREC prices have been significantly lower than 2011 prices.

Q. WHAT EXPLAINS THE REDUCTION IN IN-STATE SREC PRICES?

A. Because the in-state SREC requirement increases each year, as set forth in R.C. 4928.64(B)(2), the reduction in SREC prices can only be caused by increased supplies of in-state SRECs. Moreover, because the clearing prices in both years have been less than the Solar Alternative Compliance Payment ("SACP"), which was $400/MWh in 2011 and $350/MWh in 2012, there are clearly sufficient supplies of in-state SRECs available in the Ohio market. Thus, I conclude DP&L's justification of the "need" for Yankee Solar is not valid.

Q. SHOULD DP&L BE ALLOWED TO RECOVER THE COSTS OF THE YANKEE SOLAR FACILITY BECAUSE THE PUCO ACCEPTED THE 2010 LTFR STIPULATION, WHICH STATED THERE WAS A "NEED" FOR THE SOLAR FACILITY?

A. No. The evidence provided by DP&L to justify the "need" for Yankee Solar consisted solely of Attachment 1 to the Stipulation. That attachment failed to address DP&L's SREC requirement based on its net SSO loads and failed to account for other SREC supplies. In other words, to justify the "need" for Yankee Solar, Attachment 1 compares DP&L's <u>total</u> SREC requirement, based on the company's entire connected load against the SRECs provided by Yankee Solar. By showing that DP&L's total (in-state and out-of-state) SREC requirement is greater than the SRECs provided by Yankee Solar, DP&L supposedly "proves" the "need" for the Yankee Solar facility. This sort of "proof" cannot provide a legitimate regulatory basis for allowing DP&L to claim a "need" for Yankee Solar under R.C. § 4928.143(B)(2)(c) and, therefore, justify a nonbypassable AER-N, even as a placeholder.

The most that can be shown from the Stipulation and the PUCO's April 19, 2011 Order is that DP&L needed additional solar generation facilities to meet the increasing benchmarks in R.C. § 4928.64(B)(2). The determination of "need" under R.C. § 4928.143(B)(2)(c) requires a demonstration that "generation needs cannot be met through the competitive market."[63] No such demonstration was made by DP&L in Case No. 10-505-EL-FOR.

[63] AEP Order in Case No. 11-346-EL-SSO, p. 39 (Dec. 14, 2011).

D. <u>Approving a Nonbypassable AER-N, or Even a "Placeholder" AER-N, Will Damage Retail Competition and Harm the Ohio Economy</u>

Q. WHY WOULD IMPOSING A NONBYPASSABLE SURCHARGE FOR YANKEE SOLAR BE ANTICOMPETITIVE?

A. Imposing a nonbypassable surcharge to pay for Yankee Solar would be anticompetitive because CRES providers are also required to comply with the renewable energy requirements set forth in R.C. 4928.64(B)(2). Therefore, if a nonbypassable surcharge is imposed on DP&L customers, then customers who purchase their electricity from CRES providers would be forced to pay twice for renewable energy. They would be forced to pay for the Yankee Solar project costs <u>and</u> the costs of SRECs purchased by their CRES provider. Forcing CRES customers to pay <u>twice</u> for in-state solar RECs, while DP&L's ESP customers only pay a diluted price for Yankee Solar, harms those customers who have elected to shop and places CRES suppliers at an obvious competitive disadvantage, thus foreclosing competition. It would impose a barrier to entry in the form of an "entrance fee" for CRES suppliers to compete in the market, penalize existing CRES customers for shopping, and act as a disincentive to existing ESP customers choosing CRES providers. That is clearly anticompetitive.

Q. WOULD IMPOSING A NONBYPASSABLE SURCHARGE FOR YANKEE SOLAR BE CONTRARY TO ESTABLISHED STATE POLICY TO DEVELOP COMPETITIVE RETAIL ELECTRIC MARKETS?

A. Yes. Imposing a nonbypassable surcharge for Yankee Solar would penalize customers who wish to purchase electricity from CRES providers and, thus, would inhibit retail electric competition. That would be contrary to the plain language of R.C. 4928.02(A)-(D), and (H).

CRES providers already produce or procure all requisite energy, capacity and renewables to serve their retail customers. Forcing all DP&L customers, including those who purchase electricity from CRES providers, to pay for Yankee Solar would be discriminatory and contrary to the language of R.C. 4928.02(A). It would restrict "the availability of unbundled and comparable retail electric service that provides consumers with the supplier, price, terms, conditions, and quality options they elect to meet their respective needs," contrary to the language of R.C. 4928.02(B). It would reduce the diversity of electric suppliers, contrary to the language of R.C. 4928.02(C). It would discourage market access, contrary to the language of R.C. 4928.02(D). And, by forcing CRES customers to pay twice for in-state solar RECs, once through the nonbypassable surcharge and again for the in-state solar RECs purchased or developed by their CRES provider, it would restrict effective competition in the provision of retail electric service, contrary to the language of R.C. 4928.02(H).

Q. DP&L IS ONLY PROPOSING A "PLACEHOLDER" AER-N AT THIS TIME. HOW CAN SUCH A "PLACEHOLDER" AER-N BE ANTICOMPETITIVE?

A. A "placeholder" sends a signal to retail markets and customers. In essence, a placeholder is a "warning signal" to both CRES providers and customers, which will increase market uncertainty and affect the choices made by both customers and suppliers. Specifically, a placeholder AER-N means there is a positive probability that DP&L will be allowed to recover the costs of the Yankee Solar facility, which will force CRES customers to pay for both the costs of Yankee Solar and their CRES provider's own SREC requirements. As such, retail competition will be discouraged because SSO customers will be less likely to want to switch to a CRES provider. The reason is simple:

even the potential for an AER-N increases the expected cost of taking service from any CRES providers. This is directly contrary to established policy goals of the state.

Similarly, by increasing market uncertainty, a "placeholder" AER-N will adversely affect CRES providers and market-based solar developers. For example, if there is a positive probability that the PUCO will approve an actual nonbypassable AER-N, then CRES providers face the potential for customers returning to SSO service, so as to avoid paying twice for SRECs. This increases the difficulty – and cost – for CRES providers securing an accurate amount of energy and SRECs, and increases the exposure of CRES providers to volatile market prices. Similarly, unsubsidized, market-based developers of solar PV face greater uncertainty as to the value of future investments with a placeholder AER-N. This will reduce in-state solar investment.

Q. HOW CAN MARKET COMPETITION BE ADVERSELY AFFECTED IF DP&L IS ESTABLISHING A COMPETITIVE BID PROCESS FOR SSO LOAD?

A. As I discuss in Section V, the adverse impact on market competition stems from DP&L's proposal to continue its functional separation, and delay structural separation of its generating assets until 2018.

As part of its ESP filing, DP&L requests that both it and DPLER be allowed to bid in the CBP. Without structural separation, the potential for cross-subsidies is far higher, especially as DP&L's competitive generation unit provides DPLER with 100% of its energy requirements. Because a "placeholder" AER-N would still increase market uncertainty and reduce the likelihood of retail shopping, more DP&L customers would likely remain SSO customers to avoid the potential for double-payment of SRECs. With DPLER providing such a high percentage of retail sales and allowed to participate in the

SSO auction, and without the competitive protections provided by structural separation, the opportunities for market abuse will be enhanced.

Q. WILL AN ACTUAL AER-N OR EVEN A PLACEHOLDER ADVERSELY AFFECT THE OHIO ECONOMY?

A. Yes. Consider, for example, the switching data in Table 3, which is based on DP&L Workpapers WP-8a and WP-8b. These data show that over 75% of all commercial class customers and almost all industrial customers have switched to CRES providers.

Table 3: Retail Shopping Percentages, August 2012

Residential	Commercial	Industrial	Public Authority
25.3%	77.9%	99.0%	63.5%

The increased uncertainty imposed by a "placeholder" AER-N will increase uncertainty for these customers. Businesses and investors do not like uncertainty because uncertainty increases costs. In this case, commercial and industrial customers will face greater uncertainty that, as CRES customers, they will be forced to pay a nonbypassable AER-N, leading to higher overall electric costs.

IV. RECONCILIATION RIDER AND DEFERRAL BALANCES

Q. WHAT COSTS DOES DP&L PROPOSE TO INCLUDE IN ITS NONBYPASSABLE RECONCILIATION RIDER?

A. DP&L's proposed non-bypassable Reconciliation Rider ("RR") includes: 1) the costs of administering and implementing the CBP; 2) the cost of implementing certain competitive retail enhancements; 3) any deferred balance that exceeds 10% of the base recovery associated with the Fuel Rider, PJM Reliability Pricing Model ("RPM") Rider, Transmission Cost Recovery Rider - Bypassable ("TCRR-B"), Alternative Energy Rider ("AER"), and the Competitive Bidding True-Up ("CBT") Rider; and 4) any remaining deferral balance or credit after the Fuel, RPM, and TCRR-B are eliminated as of June 1, 2016.

Q. ON WHAT BASIS DOES DP&L JUSTIFY RECOVERY OF COSTS ASSOCIATED WITH THE CBP ON A NONBYPASSABLE BASIS?

A. According to DP&L witness Rabb,[64] the company justifies collection of the costs associated with the CBP based on the language of R.C. § 4928.142(C)(3).

Q. DOES THE LANGUAGE OF R.C. § 4928.142(C)(3) DISCUSS RECOVERY OF CBP CHARGES ON A NONBYPASSABLE BASIS?

A. No, quite to the contrary. R.C. § 4928.142(C)(3) states:

> All costs incurred by the electric distribution utility as a result of or related to the competitive bidding process or to procuring generation service to provide the standard service offer, including the costs of energy and capacity and the costs of all other products and services procured as a result of the competitive bidding process, shall be timely recovered through the standard service offer price, and, for that purpose, the commission shall approve a reconciliation mechanism, other recovery mechanism, or a combination of such mechanisms for the utility.

This provision applies to MROs, and it makes no reference whatsoever to collection of CBP costs on a <u>nonbypassable</u> basis. Instead, CBP costs are to be recovered through the bypassable SSO price.

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[64] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan*, Second Revised Direct testimony of Emily Rabb, December 12, 2012 ("Rabb Direct"), p. 9, lines 3-9. I understand that DP&L witness Seger-Lawson has adopted Ms. Rabb's testimony in its entirety.

Q. DOES DP&L WITNESS RABB PROVIDE ANY OTHER JUSTIFICATION FOR COLLECTING THE COSTS ASSOCIATED WITH ADMINISTERING THE CBP ON A NONBYPASSABLE BASIS?

A. No.

Q. IS THERE AN ECONOMIC OR REGULATORY BASIS FOR NONBYPASSABLE RECOVERY OF CBP COSTS?

A. No. Recovery of the administrative costs of a CBP on a bypassable basis is consistent with basic regulatory practice. If a CBP is the preferred approach to securing electric supplies for SSO customers, and the PUCO determines the costs incurred by DP&L to administer the CBP are prudent, known and measurable, and just and reasonable, then DP&L should be allowed to recover those costs fully.

Moreover, another basic regulatory practice is to allocate costs to those who either cause them ("cost causation") or who benefit from them ("beneficiary pays"). Neither cost causation nor beneficiary pays applies to DP&L customers who take service from CRES providers. The CBP is undertaken for SSO customers, not customers who take service from CRES providers. Therefore, there is no economic or regulatory justification for recovering the administrative costs of the CBP on a nonbypassable basis.

Q. WHAT DEFERRAL BALANCES DOES DP&L PROPOSE TO COLLECT IN THE RECONCILIATION RIDER ON A NONBYPASSABLE BASIS?

A. DP&L proposes to collect deferral balances above 10% associated with the FUEL Rider, the RPM Rider, the TCRR-B rider, the AER, and the CBT Rider.

Q. ARE THESE DEFERRAL BALANCES CURRENTLY RECOVERED ON A BYPASSABLE BASIS?

A. Yes.

Q. WHAT IS DP&L'S JUSTIFICATION FOR PROPOSING TO COLLECT THESE DEFERRAL BALANCES ON A NONBYPASSABLE BASIS?

A. According to DP&L witness Rabb, "Converting the deferral balances that exceed 10% for the FUEL Rider, the RPM Rider and TCRR-B to non-bypassable stabilizes the rate and provides benefits to both SSO customers and switched customers that may elect to return to SSO service in the future."[65] She offers the same justification for collecting deferral balances over 10% associated with the AER and CBP Riders.[66]

Q. DO YOU AGREE WITH DP&L'S JUSTIFICATION TO COLLECT DEFERRAL BALANCES ABOVE 10% ON A NONBYPASSABLE BASIS?

A. No. First, I disagree because the DP&L proposal provides an incentive to the company to allow its deferral balances to exceed 10%. The greater these balances are above that threshold, the more the costs will be allocated on a nonbypassable basis, which will discourage shopping, contrary to state policy.

Second, recovery of these deferral balances on a nonbypassable basis violates basic regulatory practice for cost allocation. Customers who take service from CRES providers are not causing these deferral balances nor benefitting from the costs that comprise the deferral balances. Therefore, there is no regulatory basis for recovering them on a nonbypassable basis.

[65] Rabb Direct, p. 10, lines 19-21.

[66] *Id.*, p. 11, lines 7-10.

Q. DO YOU AGREE WITH MS. RABB'S ARGUMENT THAT RECOVERY OF DEFERRAL BALANCES OVER 10% ON A NONBYPASSABLE BASIS STABILIZES SSO RATES?

A. No. The claim that recovery of deferral balances on a nonbypassable basis "stabilizes" SSO rates is baseless. Instead, recovery of a portion of deferral balances on a nonbypassable basis simply increases the cost of switching from SSO service, thus reducing the economic incentive to shop. Ms. Rabb posits what may be referred to as a "last man standing" argument. Specifically, she testifies that higher deferral balances,

> [w]ill lead to a higher rate, which could incentivize more customer switching. More switching would result in fewer SSO customers to pay the balance, which would lead to an even higher rate. Such a higher rate ultimately would lead to additional customer switching.[67]

In essence, Ms. Rabb is arguing that DP&L has no control over deferral balances and that such balances will inexorably rise as more SSO customers switch to CRES providers, leaving fewer and fewer SSO customers to pay the remaining balance. Under her argument, the last SSO customer would be responsible for paying all remaining deferral balances, no matter how large.

Her argument about increased switching assumes, without basis, that CRES providers do not accrue the same sorts of costs. Because CRES providers will face similar issues, her assumption of increased switching caused by recovery of deferral balances alone is flawed.

Q. DP&L WITNESS RABB ALSO TESTIFIES THAT CUSTOMERS WHO HAVE SWITCHED BENEFIT BECAUSE THEY MAY RETURN TO SSO SERVICE IN

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[67] *Id*. p. 11, lines 4-7.

THE FUTURE AND, HENCE, RECOVERY OF DEFERRAL BALANCES ON A NONBYPASSABLE BASIS IS JUSTIFIED. DO YOU AGREE?

A. No. What Ms. Rabb is describing is a "provider of last resort" ("POLR") service. I have previously testified on cost recovery for POLR service in Case No. 08-917-EL-SSO.[68] In that proceeding, I testified AEP Ohio had not identified any actual POLR-related costs it had incurred. Thus, I concluded AEP Ohio had failed to meet the basic "known and measurable" requirement for cost recovery. The PUCO agreed, stating,

> As to the POLR charge, the Commission ruled that AEP-Ohio had not provided any evidence of its actual POLR costs, and found that its unconstrained option model did not measure its POLR cost and, therefore, directed AEP-Ohio to deduct the amount of the POLR charges reflected in the Companies' rates and file revised tariffs consistent with the Entry on Remand.[69]

Similarly, neither Ms. Rabb nor any other DP&L witness has provided any evidence whatsoever of the costs associated with DP&L's POLR obligation that are included in these various riders. Therefore, such costs are not known and measurable. As such, Ms. Rabb's assertion that the deferral balances associated with these various riders benefits customers who may return to SSO service in the future has no basis in fact.

Q. DO YOU RECOMMEND THE PUCO REQUIRE DP&L TO CONTINUE RECOVERY OF ALL DEFERRAL BALANCES ON A BYPASSABLE BASIS?

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[68] *In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan Including Related Accounting Authority and an Amendment to its Corporate Separation Plan; and the Sale or Transfer Of Certain Generating Assets*, Case No. 08-917-EL-SSO, Direct Testimony of Jonathan Lesser on Behalf of the Industrial Energy Users of Ohio, June 30, 2011 ("Lesser POLR Direct").

[69] *In the Matter of the Application of Columbus Southern Power Company for Approval of its Electric Security Plan Including Related Accounting Authority and an Amendment to its Corporate Separation Plan; and the Sale or Transfer Of Certain Generating Assets*, Case No. 08-917-EL-SSO, Finding and Order, October 26, 2011, par. 3.

A. Yes. Moreover, as of June 1, 2016, the affected riders should remain in effect until any over- or under-recovery has been returned to or collected from customers, at which time the riders should be eliminated.

V. DP&L SHOULD STRUCTURALLY SEPARATE

Q. DOES DP&L PROPOSE TO CONTINUE FUNCTIONAL CORPORATE SEPARATION?

A. Yes. DP&L proposes to maintain functional separation, and to delay transfer of the ownership of its competitive generating assets to an unregulated affiliate, until December 31, 2017.[70]

Q. WHAT RISKS WILL DP&L'S CONTINUED RELIANCE ON FUNCTIONAL SEPARATION RAISE REGARDING ITS PROPOSAL TO PARTICIPATE IN THE COMPETITIVE BIDDING PROCESS?

A. To allow DP&L to maintain functional separation and participate in the proposed competitive bidding process ("CBP") for SSO load, risks five adverse impacts to that CBP: (1) cross-subsidies between regulated and unregulated activities; (2) improper cost-allocation between regulated and unregulated portions of DP&L's business; (3) lack of transparency leading to distrust of the competitive market, particularly with respect to the CBP; (4) information asymmetry between DP&L and other prospective CBP bidders; and, ultimately, (5) higher costs for all customers.

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[70] *Application of the Dayton Power and Light Company for Approval of an Electric Service Plan*, Direct testimony of Timothy Rice, p. 4, lines 71-73, and DP&L Third Amended Corporate Separation Plan.

A. Functional Separation Increases The Risk of Anticompetitive Cross-Subsidies

Q. WHY WILL FUNCTIONAL SEPARATION IN THIS CONTEXT INCREASE THE RISK OF IMPROPER CROSS SUBSIDIES?

A. Potential cross-subsidies are a concern whenever a firm provides both competitive and cost-based services. To address this concern, Ohio law called for a separation of generation from distribution and transmission as part of the actions needed to create a competitive market for generation.[71]

DP&L, as the Electric Distribution Utility ("EDU"), should be neutral as to where it procures the energy needed to serve its customers. DP&L should have no incentive to prefer one supplier of generation over another, or to seek recovery for generation-related charges or assets on its own behalf. Functional separation that includes generation-related riders, such as the SSR and the Switching Tracker, risks creating an improper incentive for DP&L to prefer its own generation over potentially cheaper options available in the competitive market, because it can subsidize its higher costs by transferring competitive generation-related costs to all distribution customers through these nonbypassable riders.

[71] *See* R.C. § 4928.02(H) (setting forth the state's policy to "Ensure effective competition in the provision of retail electric service . . . "); R.C. § 4928.17 (requiring that each utility implement a corporate separation plan "sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service. . ., " prohibiting "unfair competitive advantage" by virtue of an affiliate relationship, and limiting functional separation to only "an interim period."); *see also* R.C. § 4928.06(A), (C), (E)(1) (requiring the Commission to "monitor and evaluate the provision of retail electric service in this state. . . for the purpose of discerning any competitive retail electric service that is no longer subject to effective competition" and to "exercise [its] authority, to resolve abuses of market power by any electric utility that interfere with effective competition in the provision of retail electric service").

Q. WHY WILL FUNCTIONAL SEPARATION IN THIS CONTEXT CREATE THE POTENTIAL FOR IMPROPER COST SHIFTING?

A. Absent any separation (functional or structural), a utility with both regulated business and unregulated competitive business will have an incentive to shift costs, revenues and information between these two aspects of its business to its greatest advantage. Structural separation makes such cost-shifting transparent, so it can be easily detected and prevented.

Q. DOES DP&L MAINTAIN SEPARATE ACCOUNTING LEDGERS FOR ITS COMPETITIVE GENERATION ACTIVITIES AND ITS REGULATED TRANSMISSION AND DISTRIBUTION ACTIVITIES?

A. Yes. However, according to DP&L's response to IEU Interrogatory 1-45, "The financial results of these two units are not exact and are merely a rough approximation." The fact that DP&L does not maintain separate, <u>audited</u> accounting ledgers for its competitive generation and regulated T&D business operation segments is compelling evidence for structural separation.

With structural separation, DP&L's generating assets would be held by a separate company, which would be required to have its books audited and to conform with standard accounting practices. Cost allocation would be transparent and cross-subsidies could be easily detected and prevented.

Q. WHY ARE ACCOUNTING LEDGERS THAT ARE UNAUDITED AND PROVIDE ONLY ROUGH APPPROXIMATIONS OF FINANCIAL RESULTS PROBLEMATIC?

A. They are problematic because the presence of cross-subsidies between DP&L's regulated transmission and distribution function and its competitive generation function is unknown. Unaudited financial ledgers means there is no way to determine whether DP&L actually follows the procedures set forth in that cost allocation manual. Because DP&L admits its accounting may be inaccurate, the company's allocation of costs between regulated T&D operations and competitive generation operations is clearly suspect. Yet, as long as these separate ledgers are not audited, potential misallocation of costs and resulting cross-subsidies cannot be independently assessed.

Q. WHAT FORMS CAN COST-SHIFTING TAKE?

A. Cost-shifting to the regulated side can take many forms. For example, investment costs could be recovered through the SSR for generating assets that are used to provide the generation bid into the CBP. Labor that is shared between the regulated and unregulated functions may spend a disproportionate amount of time on competitive business issues, contrary to how their time is accounted for and charged on the regulated side.

Q. IS THERE ANY EVIDENCE THAT DP&L SUBSIDIZES GENERATION PROVIDED TO ITS SISTER COMPANY, DPLER?

A. Yes. In response to Interrogatory OCC-383(b) (attached as Exhibit JAL-17), DP&L describes how the existing fuel rider costs are calculated. Specifically, DP&L states, "the fuel and purchased power costs incurred to serve the retail customer load (inclusive of DP&L and DPL Energy Resources customers) are from the lowest portion of the least cost stack, while the remaining higher cost supplies are used to satisfy DP&L's wholesale transactions." Although this response may appear to show DP&L benefiting its SSO customers, by averaging fuel costs for SSO and DPLER customers, SSO customers incur higher fuel costs than if they were separately allocated the lowest fuel cost generating resources.

Q. CAN YOU EXPLAIN WHY THIS IS SO?

A. Yes. What DP&L describes in its response to OCC-383 is that the fuel rider is based on the combined costs of dispatching generating resources to serve its SSO customers, plus DPLER's retail customers. Within this group of generating resources, some have lower costs than others. In fact, because so much of DP&L's retail load is served by DPLER, the majority of the generating resource costs are to serve DPLER. Thus, rather than dispatching the very lowest cost generating resources for its own SSO customers, DP&L aggregates these lowest cost resources and higher cost ones to serve DP&L and DPLER customers together. As an example, suppose DP&L can serve its SSO and DPLER retail loads with the combined output of five generating resources, A – E, whose costs are increasing. Each resource generates 100 MWh, for a total of 500 MWh, as shown in Table 4.

Table 4: Hypothetical Dispatch of DP&L Generating Resources

Resource	Cost ($/MWh)	Output (MWh)	Cost ($)
A	$10.00	100	$1,000
B	$20.00	100	$2,000
C	$30.00	100	$3,000
D	$40.00	100	$4,000
E	$50.00	100	$5,000
	Total	500	$15,000
	Average Cost ($/MWh)		**$30.00**

As Table 4 shows, the average fuel cost of all five generating resources is $30/MWh. Next, assume total SSO load is 150 MWh and total DPLER retail load is 350 MWh.

Then, the cost allocated to SSO customers is ($30/MWh) *x* (150 MWh) = $4,500, and the cost allocated to DPLER's customers is ($30/MWh) *x* (350 MWh) = $10,500.

Because SSO load is 150 MWh, that load can be served it its entirety by using all of the output of generating resource A and one-half of the output of resource B. The total cost to do so will thus be $1,000 + 0.5 *x* ($2,000) = $2,000. The average fuel cost to serve SSO customer load using these two resources is thus $2,000 / 150 MWh = $13.33/MWh.

In this example, by aggregating the DP&L SSO and DPLER retail loads, SSO customers are required to pay $30/MWh in fuel costs, even though the actual fuel cost of serving their load with the least-cost resources is just $13.33/MWh. Thus, SSO customers are forced to pay an additional $2,500 above the actual fuel cost to serve their load, whereas DPLER customers receive a $2,500 subsidy. By forcing SSO customers to cross-subsidize DPLER customers, DPLER obtains an unfair competitive advantage over other CRES providers. That is anticompetitive.

Q. IF DP&L'S GENERATING RESOURCES WERE IN A SEPARATE CORPORATE ENTITY, WOULD SSO CUSTOMERS BE FORCED TO SUBSIDIZE DPLER IN THIS MANNER?

A. No. First, if DP&L's generating resources were in a separate corporate entity, customers would not be required to pay a fuel rider in the first place because fuel would be included in the competitive bid result. In the second place, the generation subsidiary would have no economic incentive to subsidize DPLER. Instead, the generation subsidiary would behave like other competitive firms and seek to maximize revenues from generation sales.

Q. DOES DP&L ARGUE THAT ITS PROPOSED SYSTEM AVERAGE COST METHOD WILL NOT HARM SSO CONSUMERS?

A. Yes. In its response to Interrogatory OCC-371, which references the revised response to Staff Data Request #5, dated January 10, 2013, DP&L asserts the impacts of the proposed fuel rider methodology will be "*de minimis*." DP&L also includes the confidential document "OCC 23 Fuel Rider Consolidated Response Summary" (attached as Confidential Exhibit JAL-18) to justify its position.

Q. DOES THIS DOCUMENT ALLAY CONCERNS OVER CROSS-SUBSIDIZATION OF DPLER SALES BY DP&L SSO CUSTOMERS?

A. No. DP&L sets forth four reasons why the proposed method is "reasonable:" (1) improved operational efficiency, because it is easier for DP&L to administer and for PUCO staff and outside experts to understand; (2) alignment of incentives between DP&L and its customers by fairly assigning the same average cost for all DP&L customers; (3) clear incentives for DP&L to manage its energy supply portfolio to achieve the least overall cost of energy supply under the ESP, and (4) that the proposed method is consistent with DP&L's proposed blending of CBP prices into SSO rates. None of these arguments addresses the fundamental issue: that DP&L's proposed methodology will be an obvious cross-subsidy to DPLER, to be paid for by SSO customers.

Q. IS IT "EASIER" AND "FAIR" FOR DP&L TO ASSIGN THE SAME SYSTEM AVERAGE COST FOR SSO CUSTOMERS AND DPLER?

A. Not when DP&L is asking for almost $700 million in subsidies for its generating facilities through the SSR over the term of the ESP. The easiest, fairest, and most economically efficient approach to encourage least-cost supplies is for DP&L to structurally separate so its generating assets are run as an entirely separate company, and for 100% of SSO load to be auctioned off immediately.[72] In doing so, there would be no need for a fuel rider whatsoever. DP&L's competitive generation subsidiary simply would operate like all other competitive generation suppliers. Competitive generation suppliers do not charge customers "fuel riders," unless by specific and mutual contractual consent (e.g., a tolling agreement or prices tied to specific fuel costs). Competitive generation suppliers have a clear economic incentive to maximize operational efficiency of their portfolio of generating units. Competitive generation suppliers do not collect subsidies for their generating units.

Q. DP&L STATES THREE "BENEFITS" OF THE PROPOSED SYSTEM AVERAGE COST METHOD. DO YOU AGREE WITH THESE?

A. I agree DP&L benefits from the proposed method. However, SSO customers do not benefit from having to cross-subsidize DPLER, which is the fundamental outcome of the proposed methodology, regardless of DP&L's disingenuous reasoning.

The first "benefit" cited by DP&L is that it "improves and simplifies the Company's proposed transition to a competitive market environment." However, as I previously discussed, DP&L has stated its generating assets have been operated competitively since the end of 2003. As documented in DP&L's responses to OCC-407 and OCC-408 (previously attached as Exhibit JAL-2), between 2002 and 2004, DP&L

[72] In the absence of structural separation the next best approach would be to require DP&L to assign the least cost portion of the stack to its SSO load first, effectively moving sales to DPLER up to the higher cost portion of the stack along with DP&L's other competitive wholesale sales.

received over $400 million in competitive transition payments. The proposed methodology, along with the proposed $687.5 million in SSR payments, obviously benefits DP&L's transition to a structurally separate generation company. Again, a far simpler and improved transition is to auction off 100% of SSO load immediately and to forbid DP&L, DPLER, or MC2 to bid in that CBP until DP&L's generation has been spun off fully into a separate, competitive entity.

DP&L also cites as a "benefit" lower overall costs and risks of providing energy to SSO customers. Although the proposed methodology clearly reduces risks to DP&L, it raises the costs paid by SSO customers. Moreover, DP&L's assertions that the new methodology reduces the likelihood of including "expensive and volatile purchased power in Fuel Rider rates" ignores the fact that purchased power may be less costly than DP&L's generating resources. By forcing SSO customers to bear higher overall average costs so as to subsidize DPLER, DP&L may indeed reduce its purchases in the wholesale market for SSO customers. The "benefits" to SSO customers of the company's doing so, however, are unclear, to say the least.

Finally, DP&L cites as a third "benefit" the *de minimis* impacts of the proposed methodology, estimated by DP&L to be 0.35% of total bypassable wholesale revenues, which I assume means a small <u>increase</u> in costs paid by SSO customers. As someone who has performed cost-benefit studies, I am not aware of cases in which an increase in cost is considered a "benefit."

Q. DOES DP&L PROVIDE ANY QUANTIFICATION OF THE TRANSITION AND RISK MITIGATION BENEFITS?

A. Not to my knowledge.

B. <u>DP&L's Proposal Raises Transparency Concerns Which May Inhibit Retail Competition.</u>

Q. HAS FERC ADDRESSED TRANSPARENCY CONCERNS WITH RESPECT TO WHOLESALE GENERATION AND TRANSMISSION?

A. Yes. FERC discussed this issue in detail when the electric transmission system was first opened up for competition with Order 888, which was issued in 1996, and allowed for functional separation of transmission and wholesale generation activities.[73]

Q. DID FERC TAKE ANY FURTHER ACTION BASED ON THE OBJECTIONS BY MARKET PARTICIPANTS?

A. Yes. Because many commenters had stated that the functional separation under Order 888 was inadequate, FERC initiated a Notice of Proposed Rulemaking ("NOPR") in 1999 to address the impact of functional separation on the competitive market and the potential for market distorting behavior by market participants.[74] As part of that NOPR, FERC extensively discussed the problems of functional unbundling.[75]

Q. CAN YOU BRIEFLY DESCRIBE FERC'S FINDINGS REGARDING THE IMPACT OF FUNCTIONAL SEPARATION ON THE COMPETITIVE MARKET?

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[73] 75 FERC 61,080 (April 24, 1996)

[74] *See* "Actual and Perceived Discriminatory Conduct by Transmission Owner to Favor their Own or Affiliated Merchant Operations," Notice of Proposed Rulemaking, Regional Transmission Organizations, Docket No. RM99-2-000, May 13, 1999 ("NOPR RTO") (Attached as Exhibit JAL-19).

[75] NOPR RTO, pp. 58-83.

A. In the NOPR, FERC acknowledged the difficulty in identifying improper behavior in the market, stating "[w]e may be seeing only the 'tip of the iceberg'"[76] regarding undue discrimination.

The Commission addressed at length the inherent difficulty of preventing undue discrimination through standards of conduct and external monitoring when only functional separation was in place:

> [a] system that attempts to control behavior that is motivated by economic self-interest through the use of standards of conduct will require constant and extensive policing. This kind of regulation goes beyond traditional price regulation and forces us to regulate very detailed aspects of internal company policy and communication… Functional unbundling does not necessarily promote light-handed regulation. It also undoubtedly imposes a cost on those entities that have to comply with the standards of conduct who face additional training and rules that create rigidities in their internal management activities. It appears, based upon our experience thus far, that no matter how detailed the standards of conduct and how intensive our enforcement, competitors will continue to be suspicious that the wall between transmission operations and power sales is being breached in subtle and hard to detect ways. The perception that many entities that operate the transmission system cannot be trusted is not a good foundation on which to build a competitive power market. It creates needless uncertainty and risk for new investments in generation.[77]

Of note, FERC also discussed the impact that the mere appearance of impropriety can have on the competitive market.

> "We consider the allegations of discrimination to be serious because, if nothing else, they represent a perception by market participants that the market is not working fairly because such participants know that integrated utilities have the incentive and opportunity to discriminate.

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[76] NOPR RTO, p. 62.

[77] Notice of Proposed Rulemaking, Regional Transmission Organizations, 87 FERC 61,173 at pgs 84-85 (1999).

Mistrust in the market can itself be a serious impediment to competition."[78]

Q. DID FERC SPECIFICALLY DISCUSS THE ROLE THAT CONFLICTING INCENTIVES CAN PLAY IN INFLUENCING MARKET BEHAVIOR?

A. Yes. FERC specifically discussed the role that conflicting incentives for market participants can have on the competitive market.

> There are growing indications, however, that the conflicting incentives that vertically integrated utilities have regarding transmission access may be too difficult to police. Many have asserted that it is not realistic even to expect functional unbundling to eliminate attempts by transmission owners to gain economic advantage. Companies have an obligation to maximize value for shareholders, and it should be no surprise that they will be aggressive in doing so.[79]

Q. WHAT ACTION DID FERC TAKE TO MITIGATE THE RISK OF ANTICOMPETITIVE BEHAVIOR BY MARKET PARTICIPANTS?

A. In 1999, FERC issued Order 2000 to mitigate against the risk of anti-competitive behavior by market participants.[80] For example, the Federal Trade Commission ("FTC") advised FERC that functional unbundling "…would leave in place the incentive and opportunity for some utilities to exercise market power in the regulated system."[81] In Order 2000, FERC called for the establishment of Regional Transmission Organizations ("RTOs"), such as PJM, to achieve structural separation.[82]

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[78] NOPR RTO, p. 64.

[79] NOPR RTO, p. 65

[80] FERC Order 2000, RM99-2-000, 89 FERC ¶ 61,285, December 20, 1999.

[81] FERC Order 2000, RM99-2-000, 89 FERC ¶ 61,285, December 20, 1999, p. 35. The FTC continued to express this view in November 15, 2002 comments provided in RM01-12-000, p 3: "The flaws in functional unbundling… have become apparent, as anticipated by the FTC staff in 1995."

[82] *Notice of Inquiry, Preventing Undue Discrimination and Preference in Transmission Service*, 112 FERC 61,299 at P 11 (2005) ("In Order No. 888, the Commission adopted a functional unbundling

In Order 2000, the Commission explained that "While we have attempted to rely on functional unbundling to address our concerns about undue discrimination, there are indications that this is difficult for transmission providers to implement and difficult for the market and the Commission to monitor and police." [83] Functional separation does not change the underlying incentive for a utility to favor its own generation assets over those of its competitors.[84] FERC concluded that "opportunities for undue discrimination continue to exist that may not be remedied adequately by functional unbundling. We further conclude that perceptions of undue discrimination can also impede the development of efficient and competitive electric markets." [85]

Q. HOW DO THE FUNCTIONAL SEPARATION ISSUES RAISED BY FERC TRANSMISSION CASES APPLY TO DP&L'S PROPOSAL?

A. As FERC discussed at length, in both the transmission and generation functions there is a potential for anti-competitive behavior through actions of a vertically integrated utility.[86]

(cont.)

approach as a remedy for undue discrimination. Since that time, the Commission has found that the incentive and opportunity for undue discrimination nonetheless continues to exist. The Commission therefore encouraged the structural separation of generation from transmission through RTOs, ISOs and similar organizations.").

[83] Order 2000 at p. 66.

[84] Order 2000, 89 FERC 61,285 at p. 66 (1999) ("vertically integrated utilities have the incentive and the opportunity to favor their generation interests over those of their competitors."); *id*. at p. 35 ("functional unbundling does not change the incentives of vertically integrated utilities to use their transmission assets to favor their own generation"); id. at pg. 65 ("we do conclude that opportunities for undue discrimination continue to exist that may not be remedied adequately by functional unbundling. We further conclude that perceptions of undue discrimination can also impede the development of efficient and competitive electric markets.").

[85] *Id*., p. 65. *See also* pp. 32-70.

[86] *See* Order 2000, 89 FERC 61,285 at p. 66 (1999)

The potential for problems with functional separation are even greater than those addressed by FERC, because DP&L treats its generating resources as a competitive business segment within a vertically integrated structure.   With transmission, it was possible for FERC to create an open and transparent forum for participation, known as the OASIS system. No such parallel is available for generation in the case of DP&L.

C. Without Structural Separation There Is The Risk Of Information Asymmetry.

Q. WHAT IS INFORMATION ASYMMETRY AND WHY IS IT PROBLEMATIC FOR DP&L'S ESP APPLICATION?

A. Information asymmetry is often present in situations in which one party possesses information not known to other parties. For example, an individual may know more about his health than a potential insurer, or a used car dealer knows more about a car than potential buyers.

Although information asymmetry applies in many situations, in the instant proceeding the information asymmetry focuses on the fact that, with only functional separation, there is a much higher risk that DP&L and its retail affiliate, DPLER, will have an information advantage over other retail competitors bidding in the auctions for SSO service. That information asymmetry would, in turn, reduce the competitiveness of the SSO auctions DP&L has proposed as part of its ESP application, and thus harm DP&L's SSO customers and retail competition in DP&L's service territory.

Q. WHY DOES DP&L'S CONTINUATION OF ONLY FUNCTIONAL SEPARATION INCREASE THE RISK OF INFORMATION ASYMMETRY?

A. Through its regulated activities, DP&L will obtain information that may be valuable to potential generation suppliers. For example, DP&L may have knowledge about retail customer expansion plans, confidential forthcoming changes in the marketplace, or other regulated business operations.

Although there are requirements for market information to be made available equally to all bidders in the formal solicitation process, not all information is the same. Historic data is likely to be made available to all, but relevant information can also include informal assessments of market developments, changing market conditions, and even rumors, all of which have value in a competitive marketplace. The difficulty is that, with DP&L only being functionally separated, it will be difficult to control and police the flow of information.

Q. HAS FERC RECOGNIZED THE POTENTIAL MARKET DISTORTING EFFECT OF INFORMATION ASYMMETRY ON COMPETITIVE MARKETS?

A. Yes, FERC has correctly recognized that even the appearance of an improper information asymmetry can lead to market distortion and loss of participant confidence in the results of an auction.

FERC has also recognized that this loss of participant confidence has a significant impact even if no intentional discrimination is ultimately established in the competitive market. In the Notice of Proposed Rulemaking that resulted in FERC Order 2000, the Commission explained:

> [W]e consider the allegations of discrimination to be serious because, if nothing else, they represent a perception by market participants that the market is not working fairly because such participants know that integrated utilities have the incentive and opportunity to discriminate. Mistrust in the market can itself be a serious impediment to competition. If

> market participants perceive that other participants have an unfair advantage through the affiliation with the transmission provider, it can inhibit their willingness to participate in the market, including, for example, building new generating units, thus thwarting the development of robust competition.[87]

Q. HAVE OTHER STATES RECOGNIZED THE MARKET DISTORTING EFFECT OF INFORMATION ASYMMETRY ON COMPETITIVE MARKETS?

A. Yes. Many states have favored or required structural separation instead of functional separation in order to prevent anticompetitive behavior. For example, Massachusetts has recognized that structural separation is "preferable to relying on functional separation through pure cost allocations within a corporate entity, as the way to insulate ratepayers from the risks inherent in a utility's engaging in both regulated and unregulated businesses."[88] As the Massachusetts' utility regulators recognized, "the corporate form used to engage in unregulated activities should be that which insulates ratepayers from the financial performance of such activities to the greatest extent possible and does not undermine the robustness of competition in the unregulated arena."[89]

Q. WHY IS STRUCTURAL SEPARATION FOR DP&L A REASONABLE REMEDY FOR THESE INFORMATION ASYMMETRY RISKS?

A. By structurally separating, several natural barriers are created which will reduce or eliminate the inappropriate transfer of information to the competitive generation side of DP&L's business. These could include physical barriers, like separate office space

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[87] Notice of Proposed Rulemaking leading to Order 2000 in Docket RM99-2-000, May 13, 1999, pg. 64-65.

[88] *In re Berkshire Gas Company*, D.T.E. 98-61, 98-87, 1998 WL 996028, pp. 22-23 (Mass. Dept. of Telecommunications and Energy Nov. 6, 1998).

[89] *Id.*

and the separation of employees, or codes of conduct governing the conduct of employees. While the imposition of such barriers goes a long way towards eliminating the inappropriate transfer of information, the counterincentives created by structural separation are even more important. The employees of each entity will have an incentive to maximize profit for their own entity.

D. <u>If DP&L Does Not Structurally Separate, There Is A Risk Of Higher Prices For Customers.</u>

Q. DO YOU BELIEVE THAT MAINTAINING FUNCTIONAL SEPARATION COULD LEAD TO HIGHER PRICES FOR DP&L'S CUSTOMERS?

A. Yes. This can be seen by following the example which was also discussed earlier. The inappropriate SSR and Switching Trackers will raise customer costs directly through a nonbypassable charge. With structural separation the inappropriate nature of the SSR and Switching Trackers not only would be clear but, as I discussed previously, would be unnecessary to maintain the financial integrity of DP&L.

In addition, there remains the issue of how DP&L would use such funding. One option would be to use it to reduce the apparent cost of power it bids into the CBP. DP&L could use the funds to support its competitive sales by making capital investments in its generation facilities. These actions would serve to discourage competition. Reduced competition should be a concern in its own right and over time can lead to higher prices as successful bids no longer have to compete against as many alternatives.[90]

[90] *See* Jonathan Lesser, "Gresham's Law of Green Energy," *Regulation*, Winter 2011, at p.14 ("Moreover, the price suppressive effect is only temporary, because it drives out actual competitors and reduces the likelihood of new competitors entering the market. (Generators will not enter the market if they think regulators and politicians will simply drive them out at a later date. Also, investors, perceiving

As discussed above, one of the primary risks of functional separation is the incentive to cross-subsidize and seek cost-recovery for unregulated lines of business. By seeking to subsidize its generation business through the SSR and Switching Tracker, DP&L seeks to impose a non-bypassable charge on distribution customers to compensate it for generation-related activities. Structural separation addresses these issues and provides a least-cost solution to maintaining the financial integrity of DP&L's regulated local distribution activities.

Q. HOW WILL CROSS-SUBSIDIES REDUCE COMPETITION AND RESULT IN HIGHER COSTS FOR CUSTOMERS IN THE CBP?

A. If DP&L is allowed to bid into the auctions while being unfairly subsidized by the SSR, Switching Tracker, and nonbypassable AER-N, this will have the net effect of reducing participation in the auction and raising the ultimate price paid by SSO customers. Any other bidder for this service will recognize DP&L is likely to be an aggressive bidder for this load, particularly with at least $138 million in annual subsidies for its bid, which no other bidder will receive. A rational bidder may decide not to participate in the auction in this circumstance, thereby reducing the number of bidders. The reduced level of competition is likely to ultimately raise the net price paid by customers.

Q. PLEASE EXPLAIN HOW CROSS-SUBSIDIES RESULT IN HIGHER PRICES IN THE CBP.

(cont.)

greater risk, will require larger expected returns.) Thus, rather than building a better mousetrap, these lawmakers are using subsidies to artificially and temporarily reduce the price of mousetraps.")

A. By its very nature, any bidder in an auction recognizes the potential to be outbid by another firm. Actively competitive firms have a general sense of their competitors and frequently try to assess how those competitors will bid, as well as their own likelihood of success. In situations where others are seen to have an advantage, a firm might not bid at all, or only put in a bid that it can assemble at low cost given the lower chances of success.

Q. WHAT IS THE MOST DIRECT MEANS OF ADDRESSING THE PROBLEMS WITH DP&L'S FUNCTIONAL SEPARATION?

A. The most direct solution to the issues I have raised would be the full structural separation of DP&L's regulated and competitive businesses, along with the elimination of unjustified cost elements in the nonbypassable charges, especially the SSR and Switching Tracker. Structural separation is more supportive of a competitive marketplace and provides greater assurance to all market participants that DP&L will not be in a position to distort competition through improper means.[91] And the unjustified cost elements should be eliminated both because of their direct effect on customers' costs and because they could provide the source of cash for improper cross-subsidization to the detriment of competitive markets.

Q. IF FUNCTIONAL UNBUNDLING IS MAINTAINED, SHOULD DP&L AND DPLER BE ALLOWED TO PARTICIPATE IN THE DP&L CBP?

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[91] R.C. § 4928.17 (requiring that each utility implement a corporate separation plan "sufficient to ensure that the utility will not extend any undue preference or advantage to any affiliate, division, or part of its own business engaged in the business of supplying the competitive retail electric service . . . ," prohibiting "unfair competitive advantage" by virtue of an affiliate relationship, and limiting functional separation to only "an interim period").

A. No. Although it is in customers' best interests to maximize participation in a CBP, that is not true when a competitor is present that is viewed as having an unfair advantage. In this case, DP&L and DPLER would be viewed by competitors as having an unfair advantage due to: (1) cross-subsidies of DP&L's and DPLER's bids into the auction through the riders it proposes; and (2) through market-distorting information asymmetry.

In fact, restrictions on DP&L's participation under these circumstances will be a strong signal to suppliers of a level playing field for DP&L's SSO supply. This will encourage more aggressive bidding to the benefit of customers, and a more robust competitive market in DP&L's territory in general. Prohibition will also serve as an incentive to DP&L to complete its transition to a more competitive business structure so that it can fully participate in the CBP.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes. However, I reserve the right to supplement my testimony as new information subsequently becomes available or in response to positions taken by other parties.

Jonathan A. Lesser, Ph.D.

President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has almost 30 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, utility financing and the cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous U.S. states; before the Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; in commercial litigation cases; and before legislative committees in Connecticut, Maryland, New Jersey, Ohio, Texas, Vermont, and Washington State. He has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is also the coauthor of *Environmental Economics and Policy*, published in 1997 by Addison Wesley Longman, *Fundamentals of Energy Regulation*, published in 2007 by Public Utilities Reports, Inc., and *Principles of Utility Corporate Finance*, published in 2011 by Public Utilities Reports, Inc. Dr. Lesser is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*.

AREAS OF EXPERTISE

- State, federal, and international electric rate regulation—cost of capital, depreciation, cost of service, cost allocation, pricing and rate design, incentive regulation, regulatory policy, wholesale and retail market design, and industry restructuring
- Commercial damages estimation and litigation
- Pipeline rate regulation
- Natural gas markets
- Cost-benefit analysis
- Economic impact analysis and input-output studies
- Environmental policy and analysis
- Market power analysis
- Load forecasting and energy market modeling
- Market valuation and due diligence
- Antitrust

SELECTED EXPERT TESTIMONY AND REPORTS

New York Association of Public Utilities

- ♦ FERC proceeding regarding formula transmission rate for Niagara Mohawk Power d/b/a National Grid (Docket No. EL12-101-000)

Subject: Allowed rate of return and capital structure.

Caribbean Utilities Company, Ltd.

- ♦ Rebuttal report on weighted average cost of capital methodology and recommendations for Caribbean Utilities Company, Ltd.

Utah Industrial Energy Users Coalition

- ♦ Proceeding before the Utah Public Service Commission (Case No. U-11035-200)

Subject: Appropriate methodology for embedded cost allocation for Rocky Mountain Power.

FirstEnergy Solutions Corp.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 12-426-EL-SSO)

  Subject: Dayton Power & Light Co., Electric Security Plan; financial integrity, anticompetitive cross-subsidization and need for structural separation

- Proceeding before the Michigan Public Service Commission (Case No. U-17032)

  Subject: Indiana & Michigan Power Co. proposed capacity charges for customers taking retail electric service.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: Revised AEP Ohio energy security plan, benefits of retail market competition.

- Proceeding before the Ohio Public Utilities Commission (Case No. 10-2929-EL-UNC)

  Subject: Appropriate price for commercial retail electric suppliers to be charged by AEP Ohio for installed capacity under the PJM Fixed Resource Requirement tariff option.

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

Industrial Energy Users of Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

  Subject: Determination of cost associated with "provider-of-last-resort" (POLR) service and AEP Ohio's use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

  Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

  Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

  Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

  Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

  Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.,* Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

  Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited*.

Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc*., Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

DPL Inc.

- Proceeding before the Ohio Board of Tax Appeals (*DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio*, Case No. 2004-A-1437)

  Subject: Economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc*., Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
  - Concurrent proceedings: *Re: Green Mountain Power Corp*., Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
  - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to

analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.

- o *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- o *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- Arkansas Public Service Commission rate proceedings
  - o *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - o *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
  - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.

- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Idaho Power Co. v. Glenns Ferry Cogeneration Partners, L.P.*, U.S. District Court, District of Idaho, Case No. 1:11-cv-00565-CWD. Expert report on damages associated with breach of power sales contract.

- *Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico.* U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. Determined the appropriate "country risk" premium for the fresh milk dairy industry in the Commonwealth of Puerto Rico.

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al*. Damages associated with abrogation of retail electric supply contracts.

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.

- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.

- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.

- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.

- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.

- *Nat'l. Association of Electric Manufacturers v. Sorrell.* U.S. District Court for the District of Vermont. Expert report and testimony on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For the COMPETE coalition, prepared a report on the economic impacts of state subsidized electric generating plants.
- For a confidential client, provided analysis on rate of return and capital structure, as well as key business and financial risks, for renegotiation of a long-term power-purchase agreement.
- For the Manhattan Institute, prepared a comprehensive report on the economic impacts of shutdown of the Indian Point Nuclear Facility.

- For Energy Choice Now, prepared a report on the economic benefits of retail electric competition in Michigan.
- For the COMPETE Coalition, prepared a report on how electric competition creates economic growth.
- For an industry group, developed econometric models of the impacts of shale gas production on U.S. natural gas and electric prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.
- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
    - Sector Issues: Basic Techniques–Energy
    - Sector Issues in Rate Design: Energy
    - Sector Issues in Rate Design: Energy–Case Studies
    - Transmission Pricing Issues
- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.
- For the South African Department of Minerals and Energy, recommended pricing methods and regulatory accounts to ensure that petroleum product prices appropriately reflected costs and to enhance the incentives for industry investment "Final Report for Task 141. "
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.

- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.
- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.

- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

EDUCATION

- PhD, Economics, University of Washington
- MA, Economics, University of Washington
- BSc, Mathematics and Economics (with honors), University of New Mexico

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.
- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College.
- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer, *Energy Policy*

- Reviewer, *Journal of Regulatory Economics*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- International Association for Energy Economics
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J, "The High Cost of Low-Value Wind Power," *Regulation*, Spring 2013, forthcoming.
- Lesser, J., "Wind Generation Patterns and the Economics of Wind Subsidies," *The Electricity Journal* 26, Jan/Feb. 2013, pp. 8-16.
- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.
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- Lesser, J., and C. Feinstein. "Defining Distributed Utility Planning." *The Energy Journal*, Special Issue, Distributed Resources: Toward a New Paradigm (1998): 41–62.
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- Lesser, J. "The Economics of Preference Power." *Research in Law and Economics* 12 (1989): 131–51.

Books and contributed chapters

- Lesser, J., and L.R. Giacchino, *Principles of Utility Corporate Finance*, Vienna, VA: Public Utilities Reports, 2011.
- Lesser, J., and L.R. Giacchino. *Fundamentals of Energy Regulation*, Vienna, VA: Public Utilities Reports, 2007.
- Lesser, J., and R. Zerbe. "A Practitioner's Guide to Benefit-Cost Analysis." In *Handbook of Public Finance*, edited by F. Thompson, 221–68. New York: Rowan and Allenheld, 1998.
- Lesser, J., D. Dodds, and R. Zerbe. *Environmental Economics and Policy*, Reading: MA: Addison Wesley Longman, 1997.

Trade press publications

- Lesser, J., "Talk Is Cheap: The UN's Doha Conference Strikes Out . . . Again," Natural Gas and Electricity (February 2013): 27-29.
- Lesser, J. "Frack Attack: Environmentalists and Hollywood Renew Attacks on Hydraulic Fracturing," *Natural Gas and Electricity* (December 2012): 30-32.

- Lesser, J., "Courts Shut Down Nuclear Licensing, Not Wasting a Waste Crisis," *Natural Gas and Electricity* (October 2012): 27-29.
- Lesser, J., "Wind Power in the Windy City, Not There When Needed," *Energy Tribune*, July 25, 2012.
- Lesser, J. "How Will EPA's Newest Regulations Affect Electric Markets?" *Natural Gas and Electricity* (June 2012): 30-32.
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- Lesser, J., "Sunburnt: Solyndra, Subsidies, and the Green Jobs Debacle," *Natural Gas & Electricity* (November 2011):30-32..
- Lesser, J., "Illinois an Example of when the Wind Doesn't Blow," *Natural Gas & Electricity* (September 2011):27-29.
- Lesser, J., "Salmon and Wind Dueling for Subsidies in the Pacific Northwest," *Natural Gas & Electricity* (July 2011):18-20.
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- Lesser, J., "Texas Two-Step: EPA's Greenhouse Gas Permitting Takeover," *Natural Gas & Electricity* (March 2011):21-23.
- Lesser, J., "Looking Forward: Energy and the Environment through 2012," *Natural Gas & Electricity* (January 2011):30-32.
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- Lesser, J., "Let the Tough Choices Begin: Affordable or Green?," *Natural Gas & Electricity* (June 2010): 27-29.

- Lesser, J., "Will Shale Gas Production be Damaged by Too Many Fraccing Complaints?," *Natural Gas & Electricity* (April 2010): 31-32.
- Lesser, J., "As the Climate Turns: The Saga Continues," *Natural Gas & Electricity* (February 2010): 29-32.
- Lesser, J. and N. Puga, "Public Policy and Private Interests: Why Transmission Planning and Cost-Allocation Methods Continue to Stifle Renewable Energy Policy Goals," *The Electricity Journal* (December 2009): 7-19.
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- Lesser, J., "Regulating Greenhouse Gas Emissions: EPA Gets Down," *Natural Gas & Electricity* (June 2009): 31-32.
- Lesser, J., "Being Reasonable While Regulating Greenhouse Gas Emissions under the Clean Air Act," *Natural Gas & Electricity* (April 2009): 30-32.
- Lesser, J., "Renewables, Becoming Cheaper, Are Suddenly Passé," *Natural Gas & Electricity* (February 2009): 30-32.
- Lesser, J., "Measuring the Costs and the Benefits of Energy Development," *Natural Gas & Electricity* (December 2008): 30-32.
- Lesser, J., "Comparing the Benefits and the Costs of Energy Development," *Natural Gas & Electricity* (October 2008): 31-32.
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- Lesser, J., and N. Puga, "PV versus Solar Thermal," *Public Utilities Fortnightly* 146 (July 2008), pp. 16-20, 27.
- Lesser, J., "Kansas Secretary Unilaterally Bans Coal Plants," *Natural Gas & Electricity* (June 2008): 30-32.
- Lesser, J., "Seeing Through a Glass, Darkly, Banks Approach Coal-Fired Power Financing," *Natural Gas & Electricity* (April 2008): 29-31.

- Lesser, J., "The Energy Independence and Security Act of 2007: No Subsidy Left Behind," *Natural Gas & Electricity* (February 2008): 29-31.
- Lesser, J., "Control of Greenhouse Gases: Difficult with Either Cap-and-Trade or Tax-and-Spend." *Natural Gas & Electricity* (December 2007): 28-31.
- Lesser, J., "Déjà vu All Over Again: The Grass was not Greener Under Utility Regulation." *The Electricity Journal* 20 (December 2007): 35–39.
- Lesser, J., "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.
- Lesser, J., "No Leg to Stand On." *Natural Gas & Electricity* (August 2007): 28–31.
- Lesser, J., "Goldilocks Chills Out." *Natural Gas & Electricity* (July 2007): 26–28.
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- Lesser, J., "Command-and-Control Still Lurks in Every Legislature." *Natural Gas & Electricity* (February 2007): 8–12.
- Lesser, J., and G. Israilevich, "The Capacity Market Enigma." *Public Utilities Fortnightly* 143 (December 2005): 38-42.
- Lesser, J., "Regulation by Litigation." *Public Utilities Fortnightly* 142 (October 2004): 24–29.
- Lesser, J., "ROE: The Gorilla is Still at the Door." *Public Utilities Fortnightly* 144 (July 2004): 19–23.
- Lesser, J., and S. Chapel, "Keys to Transmission and Distribution Reliability." *Public Utilities Fortnightly* 142 (April 2004): 58–62.
- Lesser, J., "DCF Utility Valuation: Still the Gold Standard?" *Public Utilities Fortnightly* 141 (February 15, 2003): 14–21.
- Lesser, J., "Welcome to the New Era of Resource Planning: Why Restructuring May Lead to More Complex Regulation, Not Less." *The Electricity Journal* 15 (July 2002): 20–28.
- Lesser, J., and C. Feinstein, "Identifying Applications for Distributed Generation: Hype vs. Hope." *Public Utilities Fortnightly* 140 (June 1, 2002): 20–28.

- Lesser, J., et al., "Utility Resource Planning: The Need for a New Approach." *Public Utilities Fortnightly* 140 (January 15, 2002): 24–27.
- Lesser, J., "Distribution Utilities: Forgotten Orphans of Electric Restructuring?" *Public Utilities Fortnightly* 137 (March 1, 1999): 50–55.
- Lesser, J., "Regulating Distribution Utilities in a Restructured World." *The Electricity Journal* 12 (January/February 1999): 40–48.
- Lesser, J., "Is it How Much or Who Pays? A Response to Rothkopf." *The Electricity Journal* 10 (December 1997): 17–22.
- Lesser, J., and M. Ainspan, "Using Markets to Value Stranded Costs." *The Electricity Journal* (October 1996): 66–74.
- Lesser, J., "Economic Analysis of Distributed Resources: An Introduction." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., "Distributed Resources as a Competitive Opportunity: The Small Utility Perspective." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., and M. Ainspan, "Retail Wheeling: Deja vu All Over Again?" *The Electricity Journal* 7 (April 1994): 33–49.
- Lesser, J., "An Economically Rational Approach to Least-Cost Planning: Comment." *The Electricity Journal* 4 (October 1991).
- Lesser, J., "Long-Term Utility Planning Under Uncertainty: A New Approach." Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.
- Lesser, J., "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J., "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.

Other Publications

- Lesser, J., "Wind power creates market havoc, is unreliable and costly," *Columbus* (Ohio) *Dispatch*, November 22, 2012.

- Lesser, J., and R. Bryce, "The High Cost of Closing Indian Point," *New York Post*, August 8, 2012.
- Lesser, J., "Cap-and-Trade for Gasoline?" *Wall Street Journal*, June 14, 2008, A14.
- Lesser, J., "Overblown Promises: The Hidden Costs of Symbolic Environmentalism." *Livin' Vermont* (January/February 2005): 7, 27.

Selected speaking engagements

- "The Economic Benefits of Electric Competition," Key Note Address, 17th Ohio Industrial Energy Users Conference, February 20, 2013.
- "Public Policy and Energy Markets: Good Intentions" Gone Astray," presentation to the Independent Power Producers of New York, Fall Conference, September 13, 2012.
- "EPA Regulation of Generator Emissions – Key Market Issues," Energy Bar Association, Annual Meeting, April 28, 2012.
- "Competitive Energy Markets: How are they Working?" Constellation Executive Energy Forum, November 2, 2011.
- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.
- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.

- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

INT-407. Please identify the revenues, on a yearly basis, that the Company collected through its "customer transition charge" approved in Docket No. 99-1687-EL-ETP. Please identify these amounts collected by customer class.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), and 9 (vague or undefined). Subject to all general objections, DP&L states that the billed revenue collected on an annual basis for the customer transition charge was as follows:

Customer Transition Charge

	Year		
Customer Class	2002	2003	2004
Residential	$ 58,338,417	$ 56,154,026	$ 3,063,785
Commercial	$ 39,371,283	$ 39,393,110	$ 1,793,769
Industrial	$ 37,405,224	$ 36,178,058	$ 1,991,516
Public Authorities	$ 12,484,994	$ 12,322,449	$ 694,032
Street Lighting	$ 1,013,006	$ 1,033,762	$ 25,028
Total billed revenues	$ 148,612,925	$ 145,081,405	$ 7,568,130

The billed revenue collected in 2004 was for January only. Information prior to 2002 is unavailable.

WITNESS RESPONSIBLE: Craig Jackson.

INT-408. Please identify the revenues, on a yearly basis, that the Company collected through its "regulatory transition charge" approved in Docket No. 99-1687-EL-ETP. Please identify these amounts collected by customer class.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), and 9 (vague or undefined). Subject to all general objections, DP&L states that the billed revenue collected on an annual basis for the regulatory transition charge was as follows:

Regulatory Transition Charge

	Year		
Customer Class	2002	2003	2004
Residential	$ 20,651,058	$ 19,884,617	$ 1,093,064
Commercial	$ 12,089,471	$ 12,094,734	$ 549,047
Industrial	$ 11,449,800	$ 11,042,149	$ 605,620
Public Authorities	$ 3,772,231	$ 3,711,773	$ 205,919
Street Lighting	$ 276,253	$ 282,336	$ 6,672
Total billed revenues	$ 48,238,814	$ 47,015,610	$ 2,460,321

The billed revenue collected in 2004 was for January only. Information prior to 2002 is unavailable.

WITNESS RESPONSIBLE: Craig Jackson.

RESPONSE: General Objections No. 7 (not in DP&L's possession). Subject to all general objections, DP&L admits.

ESP RFA 1-10. Admit that during 2011, DPLER accounted for approximately 5,731 million kWh of the total 6,593 million kWh supplied by CRES providers within DP&L's service territory.

RESPONSE: General Objections Nos. 7 (not in DP&L's possession) and 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L admits.

ESP RFA 1-11. Admit that in 2011 the kWh volume supplied by DPLER to retail customers in DP&L's distribution service area represented approximately 41% of DP&L's total distribution volume.

RESPONSE: General Objections No. 10 (possession of DP&L's unregulated affiliate). Subject to all general objections, DP&L admits.

ESP RFA 1-12. Admit that in 2010, DPLER began providing CRES services to business customers located outside DP&L's distribution service area.

RESPONSE: General Objections Nos. 1 (relevance) and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPLER is not a party to this case and is not subject to discovery.

ESP RFA 1-13. Admit that DPL is a regional electric energy and utility company.

RESPONSE: General Objections Nos. 1 (relevance), 9 (vague or undefined), and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPL is not a party to this case and is not subject to discovery. DP&L further objects because the terms "regional

ESP INT. 1-39. Which, if any, of the proposed non-bypassable charges identified in the application for approval of an ESP filed on October 5, 2012 are charges that are designed to provide compensation for generation-related service?

RESPONSE: Subject to all general objections, DP&L states that the Reconciliation Rider may be recovering some generation-related costs if or when the FUEL, RPM, TCRR-B, AER or CBT exceed 10% or when the FUEL, RPM, and TCRR-B riders are phased out at the time DP&L's SSO is procured 100% through competitive bid. DP&L's Service Stability Rider ("SSR") is designed to ensure DP&L's financial integrity, and therefore may provide compensation for generation costs. DP&L's proposed AER-N is designed to recover the revenue requirements associated with renewable energy and therefore is compensation for generation related costs. DP&L's switching tracker would defer costs associated with the difference between the Blended SSO price and the CB rider and therefore may be compensating DP&L for generation related costs.

WITNESS RESPONSIBLE: Dona Seger-Lawson

INT-444. Please identify the specific portion(s) of the SSR charge that supports the financial integrity of each of the following functions of DP&L's operations: generation, transmission, and distribution.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), and 6 (calls for narrative answer); in addition, this interrogatory calls for a legal conclusion. Subject to all general objections, DP&L states that the SSR supports its financial integrity as an entire company, and is not allocated to and does not support any specific DP&L functions.

WITNESS RESPONSIBLE: Dona Seger-Lawson.

INT-446. If Mr. Chambers is aware of the statutory provisions set forth in the preceding interrogatory, then please explain how it is consistent with such statutory provisions for DP&L to have its retail electric generation services subsidized in order to realize a specified return on equity.

RESPONSE: General Objections Nos. 2 (unduly burdensome) and 6 (calls for narrative answer); in addition, this interrogatory calls for a legal conclusion. Subject to all general objections, DP&L states that the purpose of the SSR and switching tracker is not to subsidize its retail electric generation services; rather, the purpose of the SSR is to permit DP&L to maintain its financial integrity as a single integrated company. DP&L further states that it seeks recovery of the SSR and switching tracker pursuant to Ohio Rev. Code § 4928.143.

WITNESS RESPONSIBLE: None.

EXHIBIT JAL-6

REDACTED

EXHIBIT JAL-7

REDACTED

INT-439. Reference: Proposed tariff Original Sheet G29, page 1. The description of Rider SSR states it is "intended to compensate DP&L for providing stabilized service for customers." Concerning this:

a. What is the definition of "stabilized service" as the term is used in the tariff?

RESPONSE: General Objections Nos. 2 (unduly burdensome) and 6 (calls for narrative answer). Subject to all general objections, DP&L states that the SSR will permit DP&L to maintain its financial integrity, and thus provide stable service.

b. How will the Company measure the stability of service provided to customers?

RESPONSE: General Objections Nos. 2 (unduly burdensome) and 6 (calls for narrative answer). Subject to all general objections, DP&L states that the SSR will permit DP&L to maintain its financial integrity, and thus provide stable service. DP&L does not propose any specific measure of stable service in connection with the SSR.

c. If the Company fails to provide "stabilized service" to customers, would customers be released from the responsibility to pay the rates under Rider SSR? Why or why not?

RESPONSE: General Objections Nos. 2 (unduly burdensome) and 6 (calls for narrative answer). Subject to all general objections, DP&L states that the SSR will permit DP&L to maintain its financial integrity, and thus provide stable service. DP&L does not have a position on what should occur in the future if the level of the SSR is not high enough to permit DP&L to maintain its financial integrity and maintain stable service.

WITNESS RESPONSIBLE: Dona Seger-Lawson.

INT-223. In establishing the level of the SSR, did Mr. Chambers quantify any measure of financial integrity other than the return on equity? If so, please provide any and all analysis showing how other measures of financial integrity were utilized to determine the level of the SSR.

RESPONSE: General Objections No. 9 (vague or undefined). Subject to all general objections, DP&L states that Mr. Chambers did not establish the level of the SSR but analyzed the SSR level requested by DP&L. His testimony identified and calculated a broad range of both business and financial factors that are considered in the determination of DP&L's financial integrity. Mr. Chambers' testimony also noted that no single factor is all-determining in ascertaining financial integrity nor is there a mechanical formula for evaluating such factors. Rather, the determination of financial integrity involves balancing these many factors.

WITNESS RESPONSIBLE: William Chambers.

<u>INTERROGATORY NO. 8-27:</u> Exhibit CLJ-2. Please explain how DP&L determined the $120 million SSR value in line 3.

RESPONSE: General Objections Nos. 2 (unduly burdensome) and 6 (calls for narrative answer). Subject to all general objections, DP&L states that it requires the $137.5 million SSR to reduce the risk of severe financial distress and ratings downgrades, as explained in the testimony of William Chambers. Furthermore, the amount of the SSR allows the company to meet it financial and operational obligations, to invest in capital, to attract capital, and the opportunity to earn a reasonable rate of return. The 5 year weighted average return (2013 – 2017), as shown on Second Revised Exhibit CLJ-2 is 6.2%.

WITNESS RESPONSIBLE: William Chambers.

INT-224. Please identify the person or persons who determined the amount of the SSR to be requested as part of the ESP filing.

RESPONSE: Subject to all general objections, DP&L states that Craig Jackson led the effort to determine the amount of the SSR.

WITNESS RESPONSIBLE: Craig Jackson.

RESPONSES TO INTERROGATORIES

ESP INT. 3-1: Since the acquisition of DPL by AES, has DP&L, DPL, or AES performed any analysis, study, and/or made any recommendations of potential cost savings measures or revenue enhancements for DP&L?

RESPONSE: General Objections Nos. 1 (relevance), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPL and AES are not subject to discovery in this matter. Subject to all general objections, DP&L states: Yes.

A. If the answer is affirmative, what were those cost savings measures or revenue enhancements?

RESPONSE: General Objection Nos. 1 (relevance), 2 (unduly burdensome), and 3 (privileged and work product). DP&L further objects because DP&L has not made any final decisions relating to reducing or eliminating expenses, and any decisions would depend on many unknown and variable factors including the results of this proceeding. DP&L's analysis of potential expense reductions constitutes protected work product, because that analysis depends upon DP&L's analysis of and expectations regarding the likely results of this proceeding; DP&L thus objects to providing the analysis that it has performed regarding potential expense reductions. DP&L has not made decisions relating to reduction or elimination of expenses and any such decisions must await the results of this case; DP&L cannot speculate as to what expense adjustments might be forced upon it. Subject to all general objections, DP&L states that its ability to reduce expenses is limited by various factors, including the requirements that DP&L comply with reliability and safety standards, and the fact that co-owners of certain of its generation assets have certain rights to operate those assets.

B. If the answer is affirmative, identify any documents containing such analysis, study, and/or recommendation.

RESPONSE: General Objection Nos. 1 (relevance), 2 (unduly burdensome), and 3 (privileged and work product). DP&L further objects because DP&L has not made any final decisions relating to reducing or eliminating expenses, and any decisions would depend on many unknown and variable factors including the results of this proceeding. DP&L's analysis of potential expense reductions constitutes protected work product, because that analysis depends upon DP&L's analysis of and expectations regarding the likely results of this proceeding; DP&L thus objects to providing the analysis that it has performed regarding potential expense reductions. DP&L has not made decisions relating to reduction or elimination of expenses and any such decisions must await the results of this case; DP&L cannot speculate as to what expense adjustments might be forced upon it.

C. If the answer is affirmative, identify when the analysis, study, and/or recommendation was made.

RESPONSE: General Objections Nos. 1 (relevance), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPL and AES are not subject to discovery in this matter. Subject to all general objections, DP&L states that please see response to part A above.

D. If the answer is affirmative, identify when the cost saving measures and/or revenue enhancements were made, or are planned to be implemented.

RESPONSE: General Objections Nos. 1 (relevance), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPL and AES are not subject to discovery in this matter. Subject to all general objections, DP&L states that please see response to part A above.

E. If the answer is affirmative, what is the amount of the expected cost savings or revenue enhancement?

RESPONSE: General Objections Nos. 1 (relevance), 4 (proprietary), and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPL and AES are not subject to discovery in this matter. Subject to all general objections, DP&L states that please see response to part A above.

F. If the answer is negative, explain why such analysis or study has not been undertaken.

RESPONSE: General Objections Nos. 1 (relevance), 2 (unduly burdensome), 4 (proprietary), 6 (calls for narrative answer), and 10 (possession of DP&L's unregulated affiliate). DP&L further objects because DPL and AES are not subject to discovery in this matter. Subject to all general objections, DP&L states not applicable.

WITNESS RESPONSIBLE: Craig Jackson

ESP INT. 1-8. If the answer to ESP INT. 1-7 is yes, identify each unbundled function and business segment for which DP&L discontinued regulatory accounting, the date on which such discontinuation was initially effective, any changes DP&L made to the initial discontinuation, and the effective date of any changes to such initial discontinuation.

RESPONSE: General Objections No. 1 (relevance). DP&L further objects because "unbundled function or business segment" is undefined and vague. Subject to all general objections, DP&L states that per the calendar year 2000 annual report:

During 1999, legislation was enacted in Ohio restructuring the state's electric utility industry causing DP&L's generation business unit to discontinue being regulated. DP&L filed a three-year transition plan at the PUCO in 1999 with final PUCO approval coming in September 2000. The three-year transition plan began in January 2001 and ended on December 31, 2003, at which time DP&L's generation business unit was fully merchant.

DP&L further states that it discontinued regulatory accounting for part of its generation function in September 2000.

WITNESS RESPONSIBLE: Craig Jackson

ESP INT. 1-39. Which, if any, of the proposed non-bypassable charges identified in the application for approval of an ESP filed on October 5, 2012 are charges that are designed to provide compensation for generation-related service?

RESPONSE: Subject to all general objections, DP&L states that the Reconciliation Rider may be recovering some generation-related costs if or when the FUEL, RPM, TCRR-B, AER or CBT exceed 10% or when the FUEL, RPM, and TCRR-B riders are phased out at the time DP&L's SSO is procured 100% through competitive bid. DP&L's Service Stability Rider ("SSR") is designed to ensure DP&L's financial integrity, and therefore may provide compensation for generation costs. DP&L's proposed AER-N is designed to recover the revenue requirements associated with renewable energy and therefore is compensation for generation related costs. DP&L's switching tracker would defer costs associated with the difference between the Blended SSO price and the CB rider and therefore may be compensating DP&L for generation related costs.

WITNESS RESPONSIBLE: Dona Seger-Lawson

BEFORE

THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Long-Term Forecast Report of Dayton Power and Light Company and Related Matters.	)))	Case No. 10-505-EL-FOR

OPINION AND ORDER

The Commission, having considered the record in this matter, and being otherwise fully advised, hereby issues its opinion and order.

APPEARANCES:

Randall V. Griffin, 1065 Woodman Drive, Dayton, Ohio 45432, on behalf of Dayton Power and Light Company.

Mike DeWine, Ohio Attorney General, by Thomas W. McNamee, Assistant Attorney General, 180 East Broad Street, Columbus, Ohio 43215, on behalf of the staff of the Public Utilities Commission of Ohio.

Janine Migden-Ostrander, Ohio Consumers' Counsel, by Richard C. Reese, Assistant Consumers' Counsel, 10 West Broad Street, Columbus, Ohio 43215.

Ohio Environmental Council, by William Reisinger, 1207 Grandview Avenue, Suite 201, Columbus, Ohio 43212.

OPINION:

I. Background

Dayton Power and Light Company (DP&L) is an electric light company, as defined by Section 4905.03(A)(3), Revised Code, and a public utility, as defined under Section 4905.02, Revised Code, and, as such, is subject to the jurisdiction of this Commission. Rule 4901:5-3-01(A), Ohio Administrative Code (O.A.C.), requires each electric utility to file annually a long-term forecast report (LTFR). On April 15, 2010, DP&L filed its 2010 LTFR.

By entry issued on June 3, 2010, the attorney examiner granted the motion for a hearing filed by the staff of the Commission (Staff), setting this matter for a public hearing on July 13, 2010. The attorney examiner found that a public hearing was required pursuant to Section 4935.04(D)(3), Revised Code, as Staff's motion demonstrated that good cause exists to hold a public hearing in this matter. Staff's motion explained that DP&L's LTFR addresses existing and imminently planned solar generation facilities for which DP&L may seek a reasonable allowance and/or non-bypassable charge under Section 4928.143(B)(2)(b) or (c), Revised Code.

On July 12, 2010, DP&L filed proofs of publication of notice of the hearing, in accordance with Section 4935.04(D)(3), Revised Code. The public hearing commenced as scheduled on July 13, 2010. No members of the public appeared at the public hearing, during which the attorney examiner granted the motions to intervene filed by the Ohio Consumers' Counsel (OCC) and Ohio Environmental Council (OEC).

DP&L, Staff, OCC, and OEC (Signatory Parties) filed a stipulation and recommendation (stipulation) resolving all issues in the case on January 14, 2011. By entry issued on January 31, 2011, this matter was set for an evidentiary hearing for the purpose of considering the stipulation.

II. Summary of the Stipulation

In the stipulation, the Signatory Parties agree that DP&L's April 15, 2010, LTFR filing substantially complies in all material respects with the requirements imposed by Chapter 4901:5-5, O.A.C. The Signatory Parties agree that, as shown on PUCO Form FE-R6 of DP&L's application, DP&L is capacity deficient in year 0 (2010) of the LTFR planning period. As explained on PUCO Form FE-R6, DP&L has already purchased approximately 400 MW of capacity for the 2010-2012 period to remedy its capacity deficiency. In addition, the Signatory Parties agree that, based on resource planning projections submitted by DP&L pursuant to the alternative energy resource requirements in Sections 4928.143(B)(2)(c), and 4929.64(B)(2), Revised Code, there is a need for a 1.1 MW solar generation facility, known as Yankee 1, and for additional solar generation facilities during the LTFR planning period.

DP&L's application explains that Yankee 1 has already been constructed and placed into service. DP&L plans to construct additional solar generating facilities to be on-line in 2012, and expects that the size of the facility or facilities to be approximately 3.9 MW. The Signatory Parties specifically agree that there is a need for the 3.9 MW facility or facilities. Plans to build additional solar generation facilities beyond 2012 will be addressed in the Company's future annual LTFR proceedings.

The stipulation also states that, in one or more separate proceedings, DP&L will seek recovery of all prudent and reasonable capital and operating costs of the Yankee 1 solar generation facility and may seek recovery of additional planned solar generation facilities. The stipulation does not prohibit a party from participating in any such cost recovery proceeding. In addition, the Signatory Parties also agree that nothing within the stipulation shall preclude a party from actively participating in *In the Matter of the Application of the Dayton Power and Light Company for Approval of a Residential and Small Commercial Renewable Energy Credit Purchase Program Agreement*, Case No. 10-262-EL-UNC.

CONCLUSION:

Rule 4901-1-30, O.A.C., authorizes parties to Commission proceedings to enter into stipulations. Although not binding on the Commission, the terms of such an agreement are accorded substantial weight. See, *Consumers' Counsel v. Pub. Util. Comm.*, 64 Ohio St.3d 123, at 125 (1992), citing *Akron v. Pub. Util. Comm.*, 55 Ohio St.2d 155 (1978). This concept is particularly valid where the stipulation is unopposed by any party and resolves almost all of the issues presented in the proceeding in which it is offered.

The standard of review for considering the reasonableness of a stipulation has been discussed in a number of prior Commission proceedings. See, e.g., *Cincinnati Gas & Electric Co.*, Case No. 91-410-EL-AIR (April 14, 1994); *Western Reserve Telephone Co.*, Case No. 93-230-TP-ALT (March 30, 1994); *Ohio Edison Co.*, Case No. 91-698-EL-FOR et al. (December 30, 1993); *Cleveland Electric Illum. Co.*, Case No. 88-170-EL-AIR (January 30, 1989); *Restatement of Accounts and Records (Zimmer Plant)*, Case No. 84-1187-EL-UNC (November 26, 1985). The ultimate issue for our consideration is whether the agreement, which embodies considerable time and effort by the signatory parties, is reasonable and should be adopted. In considering the reasonableness of a stipulation, the Commission has used the following criteria:

(1) Is the settlement a product of serious bargaining among capable, knowledgeable parties?

(2) Does the settlement, as a package, benefit ratepayers and the public interest?

(3) Does the settlement package violate any important regulatory principle or practice?

The Ohio Supreme Court has endorsed the Commission's analysis using these criteria to resolve issues in a manner economical to ratepayers and public utilities. *Indus. Energy Consumers of Ohio Power Co. v. Pub. Util. Comm.*, 68 Ohio St.3d 547 (1994) (citing *Consumers' Counsel,* supra, at 126). The Court stated in that case that the Commission may place substantial weight on the terms of a stipulation, even though the stipulation does not bind the Commission (*Id.*).

The Signatory Parties state that the stipulation is the product of lengthy, serious, arm's length bargaining among all parties to the proceeding. The Signatory Parties also maintain that the stipulation is supported by adequate data and information, represents a reasonable resolution of all issues in this proceeding, is made by parties representing a wide range of interests, and violates no regulatory principle or practice (Jt. Ex. 1 at 1-2.).

Hertzel Shamash, director of resource planning at DP&L, explains that the settlement talks involved a diverse set of interests. Mr. Shamash states that all parties were represented by experienced counsel and, in addition, all parties have participated in numerous proceedings before the Commission and are knowledgeable in regulatory matters. Mr. Shamash explains that this stipulation benefits the customers and public interests because interested parties are made aware of DP&L's plans to meet its customers' needs over the planning period in the areas of generation, transmission, and distribution service. Mr. Shamash also states that the stipulation does not violate any important regulatory practice or principle (DP&L Ex. 2 at 4-5).

Based on our review of the three-pronged test, the Commission finds the first criterion, that the process involved serious bargaining by knowledgeable, capable parties, is clearly met. The Commission finds that the stipulation filed in this case appears to be the product of serious bargaining among capable, knowledgeable parties. All parties to the stipulation have been involved in numerous cases before the Commission and have consistently provided extensive and helpful information to the Commission. In addition, the stipulation also meets the second criterion. As a package, the stipulation advances the public interest by resolving all the issues raised in this matter without resulting in extensive litigation. Finally, the stipulation meets the third criterion because it does not violate any important regulatory principle or practice. *Consumers' Counsel,* supra, at 126. Accordingly, we find that the stipulation is reasonable and should be adopted.

<u>FINDINGS OF FACT AND CONCLUSIONS OF LAW:</u>

(1) On April 15, 2010, DP&L filed its 2010 LTFR.

(2) On May 18, 2010, Staff filed a motion for a hearing.

(3) By entry issued June 3, 2010, Staff's motion for a hearing on the 2010 LTFR was granted, and a public hearing was scheduled for July 13, 2010.

(4) On July 12, 2010, DP&L filed proofs of publication for the July 13, 2010 public hearing.

(5) The public hearing was held as scheduled on July 13, 2010.

(6) OCC's and OEC's motions to intervene were granted on July 13, 2010.

(7) On January 14, 2011, DP&L, Staff, OCC, and OEC filed a stipulation resolving all issues in the case.

(8) The evidentiary hearing was held before the Commission on March 8, 2011.

(9) At the hearing, the stipulation was admitted into the record, intending to resolve all issues in this case.

(10) The stipulation meets the criteria used by the Commission to evaluate stipulations, is reasonable, and should be adopted.

(11) There is a need for a 1.1 MW solar generation facility, known as Yankee 1, and for additional solar generation facilities during the LTFR planning period.

It is, therefore,

ORDERED, That the stipulation and recommendation submitted in this case be approved and adopted in its entirety. It is, further,

ORDERED, That DP&L take all necessary steps to carry out the terms of the stipulation and this order. It is, further, ORDERED, That nothing in this opinion and order shall be binding upon the Commission in any future proceeding or investigation involving the justness or reasonableness of any rate, charge, rule, or regulation. It is, further,

ORDERED, That a copy of this opinion and order be served upon each party of record.

THE PUBLIC UTILITIES COMMISSION OF OHIO

Todd A. Snitchler, Chairman

Paul A. Centolella

Steven D. Lesser

Andre T. Porter

Cheryl L. Roberto

JJT/sc

Entered in the Journal

APR 19 2011

Betty McCauley

Betty McCauley
Secretary

PUCO FORM FE-D1: ELECTRIC UTILITY OHIO SERVICE AREA ENERGY CONSUMPTION FORECAST
(Megawatt-Hours Per Year)

		(1)	(2)	(3)	(4)	(5)	(5a)	(6)	(7)	(8)
	YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	TRANSPORTATION	OTHER (b)	ENERGY EFFICIENCY & DEMAND RESPONSE	TOTAL END USER CONSUMPTION 1+2+3+4+5-5a	LOSSES AND UNACCOUNTED FOR	NET ENERGY FOR LOAD 6+7
-5	2005	5,480,049	3,890,391	4,331,456	6,800	1,428,650		15,137,346	622,664	15,760,010
-4	2006	5,246,924	3,837,549	4,289,908	6,410	1,418,636		14,799,427	542,790	15,342,217
-3	2007	5,535,174	3,993,917	4,260,307	5,016	1,465,954		15,260,368	649,056	15,909,424
-2	2008	5,425,661	3,920,511	4,007,203	4,835	1,436,917		14,795,127	790,093	15,585,220
-1	2009	5,227,724	3,727,122	3,372,617	3,153	1,396,661		13,727,277	797,678	14,524,955
0	2010	5,395,843	3,849,181	3,323,770	4,835	1,423,248	(130,166)	13,866,711	536,146	14,402,858
1	2011	5,454,705	3,916,523	3,366,220	4,835	1,434,625	(241,343)	13,935,564	538,742	14,474,306
2	2012	5,547,272	4,011,558	3,436,440	4,835	1,443,165	(408,233)	14,035,037	542,492	14,577,529
3	2013	5,534,269	4,075,826	3,466,603	4,835	1,453,451	(564,922)	13,970,062	540,042	14,510,105
4	2014	5,580,061	4,131,578	3,470,814	4,835	1,466,218	(711,955)	13,941,551	538,967	14,480,518
5	2015	5,626,999	4,188,220	3,470,195	4,835	1,480,380	(834,228)	13,936,401	538,773	14,475,174
6	2016	5,694,549	4,244,526	3,467,715	4,835	1,497,687	(941,912)	13,967,400	539,942	14,507,342
7	2017	5,735,254	4,297,584	3,465,967	4,835	1,516,840	(1,049,742)	13,970,738	540,068	14,510,806
8	2018	5,798,795	4,344,213	3,460,937	4,835	1,538,257	(1,134,125)	14,012,912	541,658	14,554,570
9	2019	5,867,962	4,390,593	3,458,121	4,835	1,558,616	(1,209,706)	14,070,422	543,826	14,614,248
10	2020	5,937,850	4,438,168	3,460,173	4,835	1,576,742	(1,271,697)	14,146,071	546,678	14,692,749

(a) Transportation includes railroads & railways.
(b) Other includes Street & Highway Lighting, Public Authorities and Interdepartmental Sales.

JAL-16

INT-383. In response to OCC INT-335(b), DP&L states that for the existing fuel rider calculation, DP&L's generation and purchased power costs are stacked from lowest to highest.

a. How were the "stacked" costs allocated to retail customers and wholesale customers?

RESPONSE: General Objections Nos. 2 (unduly burdensome), 6 (calls for narrative answer), and 7 (not in DP&L's possession or available on PUCO website). Subject to all general objections, DP&L states that the stacked costs of the system supply needed to meet retail load (DP&L and DPL Energy Resource customers) are used to calculate a Fuel Rider rate charged to customers taking service under DP&L's SSO tariff, which pay the Fuel Rider rate in effect at the time they take service under DP&L's SSO tariff. See the produced document "OCC 23 Fuel Rider Consolidated Response Summary" for further explanation.

b. Were all of the supply requirements of the retail customers provided by the lower cost supplies before allocating the remaining higher cost supplies to satisfy DP&L's wholesale transactions?

RESPONSE: General Objections Nos. 2 (unduly burdensome), 6 (calls for narrative answer), and 7 (not in DP&L's possession or available on PUCO website). Subject to all general objections, DP&L states that in the existing Fuel Rider rate calculation, the fuel and purchased power costs incurred to serve the retail customer load (inclusive of DP&L and DPL Energy Resources customers) are from the lowest cost portion of the least cost stack, while the remaining higher cost supplies are used to satisfy DP&L's wholesale transactions. The resulting Fuel Rider rate is then only charged to customers taking service under DP&L's SSO tariff, which pay the Fuel Rider rate in effect at the time they take service under DP&L's SSO tariff. See the produced document "OCC 23 Fuel Rider Consolidated Response Summary" for further explanation.

WITNESS RESPONSIBLE: Aldyn Hoekstra.

EXHIBIT JAL-18

REDACTED

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

18 CFR Part 35

[Docket No. RM99-2-000]

Regional Transmission Organizations; Notice of Proposed Rulemaking

May 13, 1999.

AGENCY: Federal Energy Regulatory Commission.

ACTION: Notice of proposed rulemaking.

SUMMARY: The Federal Energy Regulatory Commission (Commission) is proposing to amend its regulations under the Federal Power Act (FPA) to facilitate the formation of Regional Transmission Organizations (RTOs). The Commission proposes to require that each public utility that owns, operates, or controls facilities for the transmission of electric energy in interstate commerce make certain filings with respect to forming and participating in an RTO. The Commission also proposes minimum characteristics and functions that a transmission entity must satisfy in order to be considered to be an RTO.

DATES: Initial comments are due August 16, 1999. Reply comments are due September 15, 1999.

ADDRESSES: Send comments to: Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, D.C. 20426.

FOR FURTHER INFORMATION CONTACT:
Alan Haymes (Technical Information), Office of Electric Power Regulation, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, D.C. 20426, (202) 219-2919.
Wilbur C. Earley (Technical Information), Office of Economic Policy, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, D.C. 20426, (202) 208-0100
Brian R. Gish (Legal Information), Office of the General Counsel, Federal Energy Regulatory Commission, 888 First Street, NE., Washington, D.C. 20426, (202) 208-0996

SUPPLEMENTARY INFORMATION: In addition to publishing the full text of this document in the **Federal Register**, the Commission also provides all interested persons an opportunity to inspect or copy the contents of this document during normal business hours in the Public Reference Room at 888 First Street, N.E., Room 2A, Washington, D.C. 20426.

The Commission Issuance Posting System (CIPS) provides access to the texts of formal documents issued by the Commission from November 14, 1994, to the present. CIPS can be accessed via Internet through FERC's Home page (http://www.ferc.fed.us) using the CIPS Link or the Energy Information Online icon. Documents will be available on CIPS in ASCII and WordPerfect 6.1. User assistance is available at 202-208-2474 or by E-mail to cips.master@ferc.fed.us.

This document is also available through the Commission's Records and Information Management System (RIMS), an electronic storage and retrieval system of documents submitted to and issued by the Commission after November 16, 1981. Documents from November 1995 to the present can be viewed and printed. RIMS is available in the Public Reference Room or remotely via Internet through FERC's Home page using the RIMS link or the Energy Information Online icon. User assistance is available at 202-208-2222, or by E-mail to rimsmaster@ferc.fed.us.

Finally, the complete text on diskette in WordPerfect format may be purchased from the Commission's copy contractor, RVJ International, Inc. RVJ International, Inc. is located in the Public Reference Room at 888 First Street, N.E., Washington, D.C. 20426.

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I. Introduction and Summary

In 1996 the Commission put in place the foundation necessary for competitive wholesale power markets in this country—open access transmission.[1] Since that time, the industry has undergone sweeping restructuring activity, including a movement by many states to develop retail competition, the growing divestiture of generation plants by traditional electric utilities, a significant increase in the number of mergers among traditional electric utilities and among electric utilities and gas pipeline companies, large increases in the number of power marketers and independent generation facility developers entering the marketplace, and the establishment of independent system operators (ISOs) as managers of large parts of the transmission system. Trade in bulk power markets has continued to increase significantly and the Nation's transmission grid is being used more heavily and in new ways.

As a result, the traditional means of grid management is showing signs of strain and may be inadequate to support the efficient and reliable operation that is needed for the continued development of competitive electricity markets. In addition, there are indications that continued discrimination in the provision of transmission services by vertically integrated utilities may also be impeding fully competitive electricity markets. These problems may be depriving the Nation of the benefits of lower prices, more reliance on market solutions, and lighter-handed regulation that competitive markets can bring.

If electricity consumers are to realize the full benefits that competition can bring to wholesale markets, the Commission must address the extent of these problems and appropriate ways of mitigating them. Competition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity consumers pay the lowest price possible for reliable service. We believe that further steps may need to be taken to address grid management if we are to achieve fully competitive power markets. We further believe that regional approaches to the numerous issues affecting the industry may be the best means to eliminate remaining impediments to properly functioning competitive markets.

Our objective is for all transmission owning entities in the Nation, including non-public utility entities, to place their transmission facilities under the control of appropriate regional transmission institutions in a timely manner. We seek to accomplish our objective by encouraging voluntary participation. We are therefore proposing in this rulemaking minimum characteristics and functions for appropriate regional transmission institutions; a collaborative process by which public utilities and non-public utilities that own, operate or control interstate transmission facilities, in consultation with the state officials as appropriate, will consider and develop regional transmission institutions; a willingness to consider incentive pricing on a case-specific basis and an offer of non-monetary regulatory benefits, such as deference in dispute resolution, reduced or eliminated codes of conduct, and streamlined filing and approval procedures; and a time line for public utilities to make appropriate filings with the Commission and initiate operation of regional transmission institutions. As a result, we expect jurisdictional utilities to form Regional Transmission Organizations (RTOs).

As discussed in detail herein, regional institutions can address the operational and reliability issues now confronting the industry, and any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility. Appropriate regional transmission institutions could: (1) improve efficiencies in transmission grid management[2]; (2) improve grid reliability; (3) remove the remaining opportunities for discriminatory transmission practices; (4) improve market performance; and (5) facilitate lighter handed regulation.

Thus, we believe that appropriate regional transmission institutions could successfully address the existing impediments to efficient grid operation and competition and could consequently benefit consumers through lower electricity rates resulting from a wider choice of services and service providers. There are likely to be substantial cost savings brought about by regional transmission institutions.

In light of important questions regarding the complexity of grid regionalization raised by state regulators and applicants in individual cases, we are proposing a flexible approach. We are not proposing to mandate that utilities participate in a regional transmission institution by a date certain. Instead, we act now to ensure that they consider doing so in good faith. Moreover, the Commission is not proposing a "cookie cutter" organizational format for regional transmission institutions or the establishment of fixed or specific regional boundaries under section 202(a) of the FPA.

Rather, the Commission is proposing to establish fundamental characteristics and functions for appropriate regional transmission institutions. We will designate institutions that satisfy all of the minimum characteristics and functions as Regional Transmission Organizations (RTOs). Hereinafter, the term Regional Transmission Organization, or RTO, will refer to an organization that satisfies all of the minimum characteristics and functions.

Pursuant to our authority under section 205 of the FPA to ensure that rates, terms and conditions of transmission and sales for resale in interstate commerce by public utilities are just, reasonable and not unduly discriminatory or preferential, and our authority under section 202(a) of the FPA to promote and encourage regional districts for the voluntary interconnection and coordination of transmission facilities by public utilities and non-public utilities for the purpose of assuring an abundant supply of electric energy throughout the U.S. with the greatest possible economy, we propose the following.[3]

First, the Commission proposes minimum characteristics and functions that an RTO must satisfy. Industry participants, however, retain flexibility in structuring RTOs that satisfy these characteristics and functions. For example, we do not propose to require or prohibit any one form of organization for RTOs or require or prohibit RTO ownership of transmission facilities. The characteristics and functions could be satisfied by different organizational forms, such as ISOs, transcos, combinations of the two, or even new organizational forms not yet discussed in the industry or proposed to the Commission.

Second, we propose to adopt an "open architecture" policy regarding RTOs, whereby all RTO proposals must

[1] See Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, 61 FR 21540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996) (*Order No. 888*), *order on reh'g*, Order No. 888-A, 62 FR 12274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 62 FR 64688, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *appeal docketed*, Transmission Access Policy Study Group, *et al.* v. FERC, Nos. 97-1715 *et al.* (D.C. Cir.).

[2] Appropriate regional institutions could improve efficiencies in grid management through improved pricing, congestion management, more accurate estimates of Available Transmission Capability, improved parallel path flow management, more efficient planning, and increased coordination between regulatory agencies.

[3] The Commission's legal authority is discussed in Section II.

allow the RTO and its members the flexibility to improve their organizations in the future in terms of structure, operations, market support and geographic scope to meet market needs. In turn, the Commission will provide the regulatory flexibility to accommodate such improvement.

Third, we propose guidance on flexible transmission ratemaking that may be proposed by RTOs, including ratemaking treatments that will address congestion pricing and performance based regulation. We also propose to consider on a case-by-case basis incentive pricing that may be appropriate for transmission facilities under RTO control.

Finally, all public utilities (with the exception of those participating in an approved regional transmission entity that conforms to the Commission's ISO principles) that own, operate or control interstate transmission facilities must file with the Commission by October 15, 2000 a proposal for an RTO with the minimum characteristics and functions adopted in the Final Rule,[4] or, alternatively, a description of efforts to participate in an RTO, any existing obstacles to RTO participation, and any plans to work toward RTO participation. Each proposed RTO must plan to be operational by December 15, 2001. We expect that such proposals would include the transmission facilities of public utilities as well as transmission facilities of public power and other non-public utility entities to the extent possible.

A public utility that is a member of an existing transmission entity that has been approved by the Commission as in conformance with the eleven ISO principles set forth in Order No. 888 must make a filing no later than January 15, 2001 that explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions for an RTO, or proposes to modify the existing institution to become an RTO. Alternatively, the public utility must file an explanation of efforts, obstacles and plans with respect to conforming to these characteristics and functions.

Through the required filings, utilities will make known to the public any plans for RTO participation so that other utilities and the competitive market can respond accordingly. This proposal relies primarily on the enlightened self-interest of stakeholders in each region. Such public disclosure of plans for transmission facilities will benefit the industry, the financial community, and public policy makers as the electric industry restructuring continues.

To facilitate RTO formation in all regions of the Nation, the Commission proposes to sponsor and support a collaborative process under section 202(a) to take place in the spring of 2000. Under this process, we expect that public utilities and non-public utilities, in coordination with state officials, Commission staff, and all affected interest groups, will actively work toward the voluntary development of specific RTOs.

Prior to undertaking this proposed rulemaking, we held eight technical conferences in 1998 with all industry stakeholders as well as three technical conferences this year with state regulatory commissions to obtain their views on the need for, and benefits of, regional organizations. We gained valuable insight from the participants, including many state commissions that have undertaken or are considering state retail choice programs for the consumers in their states. In light of the comments received, we wish to respond to several concerns that were raised.

First, we are not proposing to mandate RTOs, nor are we proposing detailed specifications on a particular organizational form for RTOs. The goal of this rulemaking is to get RTOs in place through voluntary participation. While this Commission has specific authorities and responsibilities under the FPA to protect against undue discrimination and remove impediments to wholesale competition, we believe it is preferable to meet these responsibilities in the first instance through an open and collaborative process that allows for regional flexibility and induces voluntary behavior.

Second, the development of RTOs is not intended to interfere with state prerogatives in setting retail competition policy. The Commission believes that RTOs can successfully accommodate the transmission systems of all states, whether or not a particular state has adopted retail competition. However, for those states that have chosen to adopt retail wheeling, RTOs can play a critical role in the realization of full competition at the retail level as well as at the wholesale level. In addition, the Commission believes that RTOs will not interfere with a state's prerogative to keep the benefits of low-cost power for the state's own retail consumers.

Third, we propose to allow RTOs to prevent transmission cost shifting by continuing our policy of flexibility with respect to recovery of sunk transmission costs, such as the "license plate" approach.

Fourth, the existence of RTOs has not, and will not in the future, interfere with traditional state and local regulatory responsibilities such as transmission siting, local reliability matters, and regulation of retail sales of generation and local distribution. In fact, RTOs offer the potential to assist the states in their regulation of retail markets and in resolving matters among states on a regional basis. They also provide a vehicle for amicably resolving state and Federal jurisdictional issues.

Finally, we do not propose to establish regional boundaries in this rulemaking. Our foremost concern is that a proposed RTO's regional configuration is sufficient to ensure that the required RTO characteristics and functions are satisfied. To this end, the Commission proposes guidance regarding the scope and regional configuration of RTOs.

We now turn to the state of the electric utility industry in the wake of Order No. 888 and how the development of RTOs achieves efficient, reliable and competitive power markets.

II. Background

In April 1996, in Order Nos. 888 and 889, the Commission established the foundation necessary to develop competitive bulk power markets in the United States: non-discriminatory open access transmission services by public utilities and stranded cost recovery rules that would provide a fair transition to competitive markets. Order Nos. 888 and 889 were very successful in accomplishing much of what they set out to do. However, they were not intended to address all problems that might arise in the development of competitive power markets. Indeed, the nature of the emerging markets and the remaining impediments to full competition have become apparent in the three years since the issuance of our orders.

A. The Foundation for Competitive Markets: Order Nos. 888 and 889

In Order Nos. 888 and 889, the Commission found that unduly discriminatory and anticompetitive

[4] An RTO proposal includes a basic agreement filed under section 205 of the FPA setting out the rules, practices and procedures under which an RTO will be governed and operated, and requests by the public utility members of the RTO under section 203 of the FPA to transfer control of their jurisdictional transmission facilities from individual public utilities to the RTO. Most RTO proposals by public utilities are likely to involve one or more filings under FPA sections 203, 205, or 206, but the number and types of filing may vary depending upon the type of RTO proposed, and the number of public utilities involved in the proposal. Under the proposed rule, a utility may file a petition for a declaratory order asking whether a proposed transmission entity would qualify as an RTO, to be followed by appropriate filings under sections 203, 205 and/or 206.

practices existed in the electric industry, and that transmission-owning utilities had discriminated against others seeking transmission access.[5] The Commission stated that its goal was to ensure that customers have the benefits of competitively priced generation, and determined that non-discriminatory open access transmission services (including access to transmission information) and stranded cost recovery were the most critical components of a successful transition to competitive wholesale electricity markets.[6]

Accordingly, Order No. 888 required all public utilities that own, control or operate facilities used for transmitting electric energy in interstate commerce to (1) file open access non-discriminatory transmission tariffs containing, at a minimum, the non-price terms and conditions set forth in the Order, and (2) functionally unbundle wholesale power services. Under functional unbundling, the public utility must: (a) take transmission services under the same tariff of general applicability as do others; (b) state separate rates for wholesale generation, transmission, and ancillary services; and (c) rely on the same electronic information network that its transmission customers rely on to obtain information about its transmission system when buying or selling power.[7] Order No. 889 required that all public utilities establish or participate in an Open Access Same-Time Information System (OASIS) that meets certain specifications, and comply with standards of conduct designed to prevent employees of a public utility (or any employees of its affiliates) engaged in wholesale power marketing functions from obtaining preferential access to pertinent transmission system information.

During the course of the Order No. 888 proceeding, the Commission received comments urging it to require generation divestiture or structural institutional arrangements such as regional independent system operators (ISOs) to better assure non-discrimination. The Commission responded that, while it believed that ISOs had the potential to provide significant benefits, efforts to remedy undue discrimination should begin by requiring the less intrusive functional unbundling approach. Order No. 888 set forth eleven principles for assessing ISO proposals submitted to the Commission.[8] Order No. 888 also stated:

> [W]e see many benefits in ISOs, and encourage utilities to consider ISOs as a tool to meet the demands of the competitive marketplace.
>
> As a further precaution against discriminatory behavior, we will continue to monitor electricity markets to ensure that functional unbundling adequately protects transmission customers. At the same time, we will analyze all alternative proposals, including formation of ISOs, and, if it becomes apparent that functional unbundling is inadequate or unworkable in assuring non-discriminatory open access transmission, we will reevaluate our position and decide whether other mechanisms, such as ISOs, should be required.[9]

In section III.A.2 of this Notice of Proposed Rulemaking, we discuss our experiences to date with functional unbundling. It has become apparent that several types of regional transmission institutions, in addition to the kinds of ISOs approved to date, may also be able to provide the benefits attributed to ISOs in Order No. 888.

B. Developments Since Order Nos. 888 and 889

In the three years since Order Nos. 888 and 889 were issued, numerous significant developments have occurred in the electric utility industry. Some of these reflect changes in governmental policies; others are strictly industry driven. These activities have resulted in a considerably different industry landscape from the one faced at the time the Commission was developing Order No. 888, resulting in new regulatory and industry challenges.

Order Nos. 888 and 889 required a significant change in the way many public utilities have done business for most of this century, and most public utilities accepted these changes and made substantial good faith efforts to comply with the new requirements. Virtually all public utilities have filed tariffs stating rates, terms and conditions for third-party use of their transmission systems. In addition, improved information about the transmission system is available to all participants in the market at the same time that it is available to the public utility as a result of utility compliance with the OASIS regulations.

The availability of tariffs and information about the transmission system has fostered a rapid growth in dependence on wholesale markets for acquisition of generation resources. Areas that have experienced generation shortages have seen rapid development of new generation resources. For example, New England, where there was deep concern about adequacy of generation supply only three years ago, now has approximately 30,000 MW of generation proposed. That response comes almost entirely from independent generating plants that are able to sell power into the bulk power market through open access to the transmission system. Power resources are now acquired over increasingly large regional areas, and interregional transfers of electricity have increased.

The very success of Order Nos. 888 and 889, and the initiative of some utilities that have pursued voluntary restructuring beyond the minimum open access requirements, have put new stresses on regional transmission systems—stresses that call for regional solutions.

1. Industry Restructuring and New Stresses on the Transmission Grid

Open access transmission and the opening of wholesale competition in the electric industry have brought an array of changes in the past several years: divestiture by many integrated utilities of some or all of their generating assets; significantly increased merger activity both between electric utilities and between electric and natural gas utilities; increases in the number of new participants in the industry in the form of independent power marketers and generators; increases in the volume of trade in the industry, particularly as marketers make multiple sales; state efforts to create retail competition; and new and different uses of the transmission grid.

With respect to divestiture, since August 1997, approximately 50,000 MW of generating capacity have been sold (or are under contract to be sold) by utilities, and an additional 30,000 MW is currently for sale. In total, this represents more than 10 percent of U.S. generating capacity. In all, according to publicly available data, 27 utilities have sold all or some of their generating assets and 7 others have assets for sale. Buyers of this generating capacity have included traditional utilities with specified service territories as well as independent power producers with no required service territory.

Since Order No. 888 was issued, there have been more than 20 applications filed with us to approve proposed mergers involving public utilities. Most of these mergers have been approved by various regulatory authorities, including the Commission, although a few have been rejected or withdrawn, and several mergers are pending regulatory approval. Most of these merger proposals have been between electric utilities with contiguous service areas, while some of the proposed mergers have been between utilities with non-

[5] *Order No. 888*, FERC Stats & Regs. at 31,682.

[6] *Id.* at 31,652.

[7] *Id.* at 31,654–55.

[8] *Id.* at 31,730.

[9] *Id.* at 31,655.

contiguous service areas. The Commission has also been presented with merger applications involving the combination of electric and natural gas assets.

There has been significant growth in the volume of trading in the wholesale electricity market. In the first quarter of 1995, according to power marketer quarterly filings, marketer sales totaled 1.8 million MWh, but by the second quarter of 1998, such sales escalated to 513 million MWh.[10] Many new competitors have entered the industry. For example, in the first quarter of 1995, there were eight power marketers (either independent or affiliated with traditional utilities) actively trading in wholesale power markets, but by the second quarter of 1998, there were 108 actively trading power marketers. The Commission has granted market-based rate authority to well over 500 wholesale power marketers, of which some are independent of traditional investor-owned utilities, some are affiliated with traditional utilities, and some are traditional utilities themselves.[11]

State commissions and legislatures have been active in the past few years studying competitive options at the retail level, setting up pilot retail access programs, and, in some states, implementing full scale retail access programs. As of May 1, 1999, 18 states have enacted electric restructuring legislation, 3 have issued comprehensive regulatory orders, and 28 others have legislation or orders pending or investigations underway.[12] Fifteen states have implemented full-scale or pilot retail competition programs that offer a choice of suppliers to at least some retail customers. Eight states have set in motion programs to offer access to retail customers by a date certain.

Because of the changes in the structure of the electric industry, the transmission grid is now being used more intensively and in different ways than in the past. The Commission is concerned that the traditional approaches to operating the grid are showing signs of strain. According to the North American Electric Reliability Council (NERC), "the adequacy of the bulk transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions."[13] These changes in the use of the transmission system "will test the electric industry's ability to maintain system security in operating the transmission system under conditions for which it was not planned or designed."[14] It should be noted that, despite the increased transmission system loadings, NERC believes that the "procedures and processes to mitigate potential reliability impacts appear to be working reliably for now," and that even though the system was particularly stressed during the summer of 1998, "the system performed reliably and firm demand was not interrupted due to transmission transfer limitations."[15]

An indication that the increased and different use of the transmission system is stressing the grid is the increased use of transmission line loading relief (TLR) procedures.[16] NERC's TLR procedures were invoked 250 times between January 1 and September 1, 1998 to prevent facility or interface overloads on the Eastern Interconnection.[17]

It appears that the planning and construction of transmission and transmission-related facilities may not be keeping up with increased requirements. According to NERC, "Business is increasing on the transmission system, but very little is being done to increase the load serving and transfer capability of the bulk transmission system."[18] The amount of new transmission capacity planned over the next ten years is significantly lower than the additions that had been planned five years ago, and most of the planned projects are for local system support.[19] NERC states that, "The close coordination of generation and transmission planning is diminishing as vertically integrated utilities divest their generation assets and most new generation is being proposed and developed by independent power producers."[20]

The transition to new market structures has resulted in new challenges and circumstances. For example, during the week of June 22–26, 1998, the wholesale electric market in the Midwest experienced numerous events that led to unprecedented high spot market prices. Spot wholesale market prices for energy briefly rose as high as $7,500 per MWh, compared to an average price for the summer of approximately $40 per MWh in the Midwest if the price spikes are excluded.[21] This experience led to calls for price caps, allegations of market power, and a questioning of the effectiveness of transmission open access and wholesale electric competition.

The Commission staff undertook an investigation of the price spike incident. Staff's report concluded that the unusually high price levels were caused by a combination of factors, particularly above-average generation outages, unseasonably hot temperatures, storm-related transmission outages, transmission constraints, poor communication of price signals, lowered confidence in the market due to a few contract defaults, and inexperience in dealing with competitive markets.[22]

The Commission's staff found that the market institutions were not adequately prepared to deal with such a dramatic series of events. Regarding regional transmission entities, the staff report observed: "The necessity for cooperation in meeting reliability concerns and the Commission's intent to foster competitive market conditions underscores the importance of better regional coordination in areas such as maintenance of transmission and generation systems and transmission planning and operation."[23] Support for this view comes from many sources. For example, the Public Utilities Commission of Ohio, in its own report on the price spikes, recommended that policy makers "take unambiguous action to require coordination of transmission system operations by regionwide Independent System Operators."[24]

On September 29, 1998, the Secretary of Energy Advisory Board Task Force on Electric System Reliability published its

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[10] Power marketer quarterly filings, *cited in Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998*, (September 22, 1998) (Staff Price Spike Report) at 3–1 to 3–2. It must be noted that a significant portion of the sales represent the retrading of power by a number of different market participants. In other words, there may be multiple resales of the same generation.

[11] *Id.* at 3–1.

[12] "Status of Electric Utility Deregulation Activity as of May 1, 1999," Energy Information Administration.

[13] Reliability Assessment 1998–2007, North American Electric Reliability Council (September 1998), at 26.

[14] *Id.*

[15] *Id.*

[16] The TLR procedures are designed to remedy overloads that result when a transmission line or other transmission equipment carries or will carry more power than its rating, which could result in either power outages or damage to property. The TLR procedures are designed to bring overloaded transmission equipment to within NERC's Operating Security Limits essentially by curtailing transactions contributing to the overload. *See* North American Electric Reliability Council, 85 FERC ¶ 61,353 (1998) (*NERC*).

[17] Reliability Assessment 1998–2007 at 27.

[18] *Id.* at 26.

[19] *Id.* at 7.

[20] *Id.*

[21] Staff Price Spike Report at 3–8 to 3–11.

[22] *Id.* at v.

[23] *Id.* at 5–8.

[24] Ohio's Electric Market, June 22–26, 1998, What Happened and Why, A Report to the Ohio General Assembly, at iii.

final report.[25] The Task Force was convened in January 1997 to provide advice to the Department of Energy on critical institutional, technical, and policy issues that need to be addressed in order to maintain bulk power electric system reliability in a more competitive industry. The Task Force found that "the traditional reliability institutions and processes that have served the Nation well in the past need to be modified to ensure that reliability is maintained in a competitively neutral fashion;" that "grid reliability depends heavily on system operators who monitor and control the grid in real time;" and that "because bulk power systems are regional in nature, they can and should be operated more reliably and efficiently when coordinated over large geographic areas."[26]

The report noted that many regions of the United States are developing ISOs as a way to maintain electric system reliability as competitive markets develop. According to the Task Force, ISOs are significant institutions to assure both electric system reliability and competitive generation markets. The Task Force concluded that a large ISO would: (1) be able to identify and address reliability issues most effectively; (2) internalize much of the loop flow caused by the growing number of transactions; (3) facilitate transmission access across a larger portion of the network, consequently improving market efficiencies and promoting greater competition; and (4) eliminate "pancaking" of transmission rates, thus allowing a greater range of economic energy trades across the network.[27]

2. Successes, Failures, and Haphazard Development of Regional Transmission Entities

Since Order No. 888 was issued, there have been both successful and unsuccessful efforts to establish ISOs, and other efforts to form regional entities to operate the transmission facilities in various parts of the country. While we are encouraged by the success of some of these efforts, it is apparent that the results have been inconsistent, and much of the country's transmission facilities remain outside of an operational regional transmission institution.

Proposals for the establishment of five ISOs have been submitted to and approved, or conditionally approved, by the Commission. These are the California ISO,[28] the PJM ISO,[29] ISO New England ISO,[30] the New York ISO,[31] and the Midwest ISO.[32] In addition, the Texas Commission has ordered an ISO for the Electric Reliability Council of Texas (ERCOT).[33] Moreover, our international neighbors in Canada and Mexico are also pursuing electric restructuring efforts that include various forms of regional transmission entities.[34]

The PJM, New England and New York ISOs were established on the platform of existing tight power pools. It appears that the principal motivation for creating ISOs in these situations was the Order No. 888 requirement that there be a single system wide transmission tariff for tight pools. In contrast, the establishment of the California ISO and the ERCOT ISO was the direct result of mandates by state governments. The Midwest ISO, which is not yet operational, is unique. It began through a consensual process and was not driven by a pre-existing institution. Two states in the region subsequently required utilities in their states to participate in either a Commission-approved ISO (Illinois and Wisconsin), or sell their transmission assets to an independent transmission company (Wisconsin).

The approved ISOs have similarities as well as differences. All five Commission-approved ISOs operate, or propose to operate, as non-profit organizations. All five ISOs include both public and non-public utility members. However, among the five, there is considerable variation in governance, operational responsibilities, geographic scope and market operations. Four of the ISOs rely on a two-tier form of governance with a non-stakeholder governing board on top that is advised, either formally or informally, by one or more stakeholder groups. In general, the final decision making authority rests with the independent non-stakeholder board. One ISO, the California ISO, uses a board consisting of stakeholders and non-stakeholders.

Four of the five ISOs operate traditional control areas, but the Midwest ISO does not currently plan to operate a traditional control area. Three are multi-state ISOs (New England, PJM and Midwest), while two ISOs (California and New York) currently operate within a single state. The current Midwest ISO members do not encompass one contiguous geographic area and there are holes in its coverage. The ISO New England administers a separate NEPOOL tariff, while the other four administer their own ISO transmission tariffs.

Three ISOs operate or propose to operate centralized power markets (New England, PJM and New York), and one ISO (California) relies on a separate power exchange (PX) to operate such a market.[35] The Midwest ISO did not originally envision an ISO-related centralized market for its region.[36] In addition, at least one separate PX has begun to do business in California apart from the PX established through the restructuring legislation.[37]

Not all efforts to create ISOs have been successful. For example, after more than two years of effort, the proponents of the IndeGO ISO in the Pacific Northwest and Rocky Mountain regions ended their efforts to create an ISO. More recently, members of MAPP, an existing power pool that covers six U.S.

[25] Maintaining Reliability in a Competitive U.S. Electricity Industry; Final Report of the Task Force on Electric System Reliability (Sept. 29, 1998) (Task Force Report). The Task Force was comprised of 24 members representing all major segments of the electric industry, including private and public suppliers, power marketers, regulators, environmentalists, and academics.

[26] Task Force Report at x–xi.

[27] *Id.* at 76.

[28] Pacific Gas & Electric Company, *et al.*, 77 FERC ¶61,204 (1996), *order on reh'g*, 81 FERC ¶61,122 (1997) (*Pacific Gas & Electric*).

[29] Pennsylvania-New Jersey-Maryland Interconnection, *et al.*, 81 FERC ¶61,257 (1997), *reh'g pending* (PJM).

[30] New England Power Pool, 79 FERC ¶61,374 (1997), *order on reh'g*, 85 FERC ¶61,242 (1998) (order conditionally authorizing ISO New England); New England Power Pool, 83 FERC ¶61,045 (1998), *reh'g pending* (order on NEPOOL tariff and restructuring) (*NEPOOL*).

[31] Central Hudson Gas & Electric Corporation, *et al.*, 83 FERC ¶61,352 (1998), *order on reh'g*, 87 FERC ¶61,135 (1999) (*Central Hudson*).

[32] Midwest Independent Transmission System Operator, *et al.*, 84 FERC ¶61,231, *order on reconsideration*, 85 FERC ¶61,250, *order on reh'g*, 85 FERC ¶61,372 (1998) (*Midwest ISO*).

[33] *See* 16 Texas Administrative Code § 23.67(p).

[34] *See* Policy Proposal for Structural Reform of the Mexican Electricity Industry, Secretary of Energy, Mexico (February 1999); Third Interim Report of the Ontario Market Design Committee (October 1998); TransAlta Enterprises Corporation, 75 FERC ¶61,268 at 61,875 (1996) (recognition of the restructuring in the Province of Alberta, Canada to create a Grid Company of Alberta).

[35] The California PX offers day-ahead and hour-ahead markets and the ISO operates a real-time energy market. Participation in the PX market is voluntary except that the three traditional investor-owned utilities in California must bid their generation sales and purchases through the PX for the first five years. New York will offer day-ahead and real-time energy markets that will be operated by the ISO. PJM and New England offer only real-time energy markets, although PJM has proposed to operate a day-ahead market. The ERCOT ISO is the only other ISO that does not currently operate a PX.

[36] There are indications, however, that the Midwest ISO is considering the formation of a power exchange. *See* Joint Committee for the Development of a Midwest Independent Power Exchange, "Solicitation of Interest-Creation of an Independent Power Exchange for the U.S. Midwest," February 5, 1999.

[37] *See* Automated Power Exchange, Inc., 82 FERC ¶ 61,287, *reh'g denied*, 84 FERC ¶ 61,020 (1998), *appeals docketed*, No. 98-1415 (D.C. Cir. Sept. 14, 1998) and No. 98-1419 (D.C. Cir. Sept. 14, 1998).

states and two Canadian provinces, failed to achieve consensus for establishing a long-planned ISO. In the Southwest, proponents of the Desert Star ISO have not been able to reach agreement on a formal proposal after more than two years of discussion.

Various reasons have been advanced to explain why it is difficult to form a voluntary, multi-state ISO. These include cost shifting in transmission capital costs; disagreements about sharing of ISO transmission revenues among transmission owners; difficulties in obtaining the participation of publicly-owned transmission facilities; concerns about the loss of transmission rights and prices embedded in existing transmission agreements; the likelihood of not being able to maintain or gain a competitive advantage in power markets through the use of transmission facilities; and the preference of certain transmission owners to sell or transfer their transmission assets to a for-profit transmission company in lieu of handing over control to a non-profit ISO.

Apart from these efforts to create ISOs, we have received proposals for other types of transmission entities. For example, in October 1998 a group of Arizona entities filed a request with the Commission to create an "independent scheduling administrator" (ISA) in Arizona.[38] Unlike an ISO, this entity would not administer its own transmission tariff nor would it have any direct operational responsibilities. Instead, it appears that its functions would be limited to monitoring the scheduling decisions and OASIS site operation of the Arizona utilities that operate transmission facilities.[39] In case of disputes, the ISA would provide a type of expedited dispute resolution process. The applicants state that the ISA would be a transitional organization that would ultimately evolve or be merged into a stronger, multi-state ISO.[40] In other developments, one public utility has recently made a filing with us to sell its transmission assets to a newly formed affiliate.[41] Another public utility recently filed a request for declaratory order asking us to find that its proposal to transfer its transmission assets (in the form of ownership or a lease) to a "transco" in return for a passive ownership interest in the transco, would satisfy the Commission's eleven ISO principles.[42]

As part of general restructuring initiatives, several states now require independent grid management organizations. For example, an Illinois law requires that its utilities become members of a FERC-approved regional ISO by March 31, 1999, and Wisconsin law gives its utilities the option of joining an ISO or selling their transmission assets to an independent transmission company by June 30, 2000. In both states, the backstop is a single-state organization if regional organizations are not developed. Recently, Virginia and Arkansas have also enacted legislation requiring their electric utilities to join or establish regional transmission entities.

3. The Commission's ISO and RTO Inquiries; Conferences with Stakeholders and State Regulators

In light of the various restructuring activities occurring throughout the U.S., the Commission has, within the past year, held 11 public conferences in 9 different cities across the country to hear the views of industry, consumers, and state regulators with respect to the need for RTOs and their appropriate roles and responsibilities.

The Commission initiated an inquiry in March 1998 pertaining to its policies on ISOs. A notice establishing procedures for a conference gave the following rationale:

> In Order Nos. 888 and 889 and their progeny, the Commission established the fundamental principles of non-discriminatory open access transmission services. Nevertheless, many issues remain to be addressed if the Nation is to fully realize the benefits of open access and more competitive electric markets.
>
> * * * * *
>
> Given the dramatic changes taking place in both wholesale and retail electric markets and the many proposals under consideration with respect to the creation of ISOs or other transmission entities, such as transmission-only utilities, it is time for the Commission to take stock of its policies in order to determine whether they appropriately support our dual goals of eliminating undue discrimination and promoting competition in electric power markets.[43]

Accordingly, the Commission held a series of eight conferences in 1998 to gain insight into participants' views on the formation and role of ISOs in the electric utility industry. The first conference was held in April 1998 at the Commission's offices in Washington, D.C. Between May 28 and June 8, 1998, the Commission held seven regional conferences in Phoenix, Kansas City, New Orleans, Indianapolis, Portland, Richmond and Orlando. As a result of these conferences, the Commission heard approximately 145 oral presentations and received a large number of written comments on the appropriate size, scope, organization and functions of regional transmission institutions. A number of different viewpoints were expressed. They will be discussed elsewhere in this NOPR and are summarized in Appendix A hereto.

On October 1, 1998, the Secretary of Energy delegated his authority under section 202(a) of the FPA to the Commission. In doing so the Secretary stated that section 202(a) "provides DOE with sufficient authority to establish boundaries for Independent System Operators (ISOs) or other appropriate transmission entities."[44] The Secretary also stated,

> FERC is also increasingly faced with reliability-related issues. Providing FERC with the authority to establish boundaries for ISOs or other appropriate transmission entities could aid in the orderly formation of properly-sized transmission institutions and in addressing reliability-related issues, thereby increasing the reliability of the transmission system.

On November 24, 1998, we gave notice in this docket of our intent to initiate a consultation process with State commissions pursuant to section 202(a).[45] The purpose of the consultations was to afford State commissions a reasonable opportunity to present their views with respect to appropriate boundaries for regional transmission institutions and other issues relating to RTOs. Conferences with State commissioners were held in St. Louis, Missouri on February 11, 1999; in Las Vegas, Nevada on February 12, 1999; and in Washington, D.C. on February 17, 1999. In all, we heard oral presentations by representatives of 41 state commissions during these consultations, with others monitoring or providing written comments.[46] During these sessions, we received much valuable advice. We have set forth in Appendix B a summary of the comments received, and discuss in

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[38] Arizona Independent Scheduling Administrator Association, Docket No. ER99-388-000 (filed October 29, 1998).

[39] A proposal for a similar entity has been in the Pacific Northwest. This entity, described as an independent grid scheduler, would make actual scheduling decisions rather than simply monitoring the decisions made by current transmission owners. *See* Regional ISO Conference (Portland), transcript at 39-40.

[40] *See* Applicant's filing, Docket No. ER99-388-000, at 3.

[41] FirstEnergy, Inc., Docket No. EC99-53-000 (filed March 19, 1999).

[42] Entergy Services, Inc., Docket No. EL99-57-000 (filed April 5, 1999).

[43] Inquiry Concerning the Commission's Policy on Independent System Operators, Notice of Conference, Docket No. PL98-5-000, at 1-2 (March 13, 1998).

[44] 63 FR 53889 (1998).

[45] Notice of Intent to Consult Under Section 202(a), 63 FR 66158 1998*), FERC Stats & Regs. ¶ 35,534 (1998).

[46] *See* Appendix B for a list of commenters.

Section III.B below our response to some of the major concerns expressed.

C. Statutory Framework

The Commission is granted the authority and responsibility by FPA sections 205 and 206, 16 U.S.C. 824d, 824e, to ensure that the rates, charges, classifications, and service of public utilities (and any rule, regulation, practice, or contract affecting any of these) are just and reasonable and not unduly discriminatory, and to remedy undue discrimination in the provision of such services. In fulfilling its responsibilities under FPA sections 205 and 206, the Commission is required to address, and has the authority to remedy, undue discrimination and anticompetitive effects. The Commission has a statutory mandate under these sections to ensure that transmission in interstate commerce and rates, contracts, and practices affecting transmission services, do not reflect an undue preference or advantage (or undue prejudice or disadvantage) and are just, reasonable, and not unduly discriminatory or preferential.[47] Additionally, as discussed in Order No. 888,[48] there is a substantial body of case law that holds that the Commission's regulatory authority under the FPA "clearly carries with it the responsibility to consider, in appropriate circumstances, the anticompetitive effects of regulated aspects of interstate utility operations pursuant to [FPA] §§ 202 and 203, and under like directives contained in §§ 205, 206, and 207." [49]

The Commission also has the authority and responsibility under section 203 of the FPA to review mergers and other transactions involving public utilities, including dispositions of jurisdictional facilities by public utilities. This includes public utilities' transfers of control of jurisdictional transmission facilities to entities such as RTOs. Under section 203, the Commission must approve a proposed disposition of jurisdictional facilities if it is consistent with the public interest. The Commission may grant an application under section 203 upon such terms and conditions as it finds necessary to secure the maintenance of adequate service and the coordination in the public interest of jurisdictional facilities.

Further, section 202(a) of the FPA, whose authority has recently been delegated to the Commission by the Secretary of Energy,[50] authorizes and directs the Commission "to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy * * *." The purpose of this division into regional districts is for "assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources * * *." Section 202(a) states that it is "the duty of the Commission to promote and encourage such interconnection and coordination within each such district and between such districts."

III. Discussion

A. Barriers to Assuring an Abundant Supply of Electric Energy Throughout the United States with the Greatest Possible Economy

In light of our experiences with ISOs and other utility restructuring activity in the aftermath of Order Nos. 888 and 889, and after almost three years of experience with implementation of Order Nos. 888 and 889, we believe that there remain important transmission-related impediments to a competitive wholesale electric market. We have grouped these remaining impediments into two broad categories. The first category of impediments consists of engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid—inefficiencies that, in and of themselves, are hindering fully competitive power markets and imposing unnecessary costs on electric consumers. The second category of impediments consists of continuing opportunities for transmission owners to unduly discriminate in the operation of their transmission systems so as to favor their own or their affiliates' power marketing activities. Both sets of impediments unnecessarily restrict the scope of bulk power markets and inhibit the large-scale competition that we sought in issuing Order Nos. 888 and 889.

The situation of the electric industry is somewhat analogous to the natural gas industry after the initial step of open access transportation was taken. In 1985, the Commission issued Order No. 436,[51] which instituted open-access, nondiscriminatory transportation of natural gas with the goal of increasing competition and permitting gas users to purchase gas directly from gas merchants. However, the Commission subsequently found that open access alone was not sufficient to remove all barriers to competition. [52] Because of the different structures of the electric and gas industries, the specific remaining impediments to competition may not be the same, but there are similarities in that open access, without sufficient mechanisms for ensuring that such access is equal and efficient for all participants, may not be enough to promote a fully competitive market. [53]

Our current understanding of industry conditions, as set forth below, will be enhanced by future consultations with and analysis from all industry stakeholders, including state commissions. The Commission seeks comments in order to achieve a deeper

[47] Once such a finding is made, the Commission is required to remedy it. *See, e.g.*, Southern California Edison Company, 40 FERC ¶ 61,371 at 62,151–52 (1987), *order on reh'g* 50 FERC ¶ 61,275 at 61,873 (1990), *modified sub nom.*, Cities of Anaheim v. FERC, 941 F.2d 1234 (D.C. Cir. 1991); Delmarva Power and Light Company, 24 FERC ¶ 61,199 at 61,466, *order on reh'g* 24 FERC ¶ 61,380 (1983).

[48] *Order No. 888*, FERC Stats. & Regs. at 31,669.

[49] Gulf States Utilities Co. v. FPC, 411 U.S. 747, 758–59, *reh'g denied*, 412 U.S. 944 (1973) (Gulf States). *See also* City of Huntingburg v. FPC, 498 F.2d 778, 783–84 (D.C. Cir. 1974) (Commission has a duty to consider the potential anticompetitive effects of a proposed Interconnection Agreement.)

[50] 63 FR 53889 (1998).

[51] Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Order No. 436, 50 FR 42408 (Oct. 18, 1985), FERC Stats. & Regs. [Regulations Preambles 1982–1985] ¶ 30,665 1985), *vacated and remanded*, Associated Gas Distributors v. FERC, 824 F.2d 981 (D.C. Cir. 1987), *cert. denied*, 485 U.S. 1006 (1988), *readopted on an interim basis*, Order No. 500, 52 FR 30334 (Aug. 14, 1987), FERC Stats. & Regs. [Regulations Preambles, 1986–1990] ¶30,761 (1987), *remanded*, American Gas Association v. FERC, 888 F.2d 136 (D.C. Cir. 1989), *readopted*, Order No. 500–H, 54 FR 52334 (Dec. 21, 1989), FERC Stats. & Regs. [Regulations Preambles 1986–1990] ¶ 30,867 (1989), *reh'g granted in part and denied in part*, Order No. 500–I, 55 FR 6605 (Feb. 26, 1990), FERC Stats. & Regs. [Regulations Preambles 1986–1990] ¶ 30,880 (1990), *aff'd in part and remanded in part*, American Gas Association v. FERC, 912 F.2d 1496 (D.C. Cir. 1990), *cert. denied*, 111 S. Ct. 957 (1991).

[52] In the case of natural gas, we found that the principal remaining barrier was the continued existence of bundled city-gate firm sales service that had a transportation component of higher quality than available through open access. Hence, we issued Order No. 636 to unbundle services and equalize the quality of service offered. *See* Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation and Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 57 FR 13267 (April 16, 1992), III FERC Stats. & Regs. ¶ 30,939 (April 8, 1992), *reh'g granted and denied in part*, Order No. 636–A, 57 FR 36128 (August 12, 1992), III FERC Stats. & Regs. ¶ 30,950 (August 3, 1992), *order on reh'g* Order No. 636–B, 57 FR 57911 (December 8, 1992), 61 FERC ¶ 61,272 (1992), Notice of Denial of Rehearing (January 8, 1993), 62 FERC ¶ 61,007 (1993), *aff'd in part and vacated and remanded in part*, United Dist. Companies v. FERC, 88 F.3d 1105 (D.C. Cir. July 16, 1996), *order on remand*, Order No. 636–C, 78 FERC ¶ 61,186 (1997).

[53] For a discussion of the similarities and differences in the structure and regulation of the natural gas and electric industries, *see generally Santa and Sikora, Open Access And Transition Costs: Will The Electric Industry Transition Track The Natural Gas Restructuring?, 15 Energy L.J. 273 (1994).*

appreciation of any impediments to competition in the Nation's electricity markets and how they should be addressed.

1. Engineering and Economic Inefficiencies in the Operation, Planning and Expansion of Regional Transmission Grids

The transmission facilities of any one utility in a region are part of a larger, integrated transmission system. From an electrical engineering perspective, each of the three interconnections in the United States (the Eastern, the Western and ERCOT) operates as a single "machine." [54] The Eastern Interconnection also extends into Canada, and the Western Interconnection includes parts of Canada and Mexico.

Problems have arisen over the last three years, in part, because we have multiple operators of each of these machines. Each separate operator usually makes independent decisions about the use, limitations and expansion of its piece of the interconnected grid based on incomplete information. This approach—separate operation of each utility's own transmission facilities—would make engineering sense only if each system operated independently of the others. But the physical reality is that, within the three interconnected grids, any action taken by one transmission provider can have major and instantaneous effects on the transmission facilities of all other transmission providers.[55]

This is not a new phenomenon. Since the very first transmission interconnection between two neighboring utilities, interconnected utilities have had to cope with the fact that electricity will flow over others' lines. In the past, these effects were often small or infrequent and the utility could generally pass any costs through to captive customers. Today, with the increase in bulk power trade and the large shifts in power flows, the effects may be large, frequent and not recoverable by the utility bearing the cost.

Another important change is that the structure of the industry that exists today is very different from the industry that existed three years ago when we issued Order No. 888. The industry is no longer composed uniformly of vertically-integrated, self-sufficient public utilities that do not compete with each other. Instead, it is an increasingly de-integrated and decentralized industry with many new and existing participants that actively compete against each other.[56]

As a consequence of these changes in trade patterns and industry structure, certain operational problems have become more significant and more difficult to resolve. These include: maintaining reliable grid operations; determining available transmission capability (ATC); [57] managing transmission congestion; and planning and investing in new transmission facilities. In addition, traditional approaches to the pricing and provision of transmission service may be hindering the further development of competitive and efficient bulk power markets. These impediments include: pancaking of transmission access charges; non-market approaches to managing congestion; the absence of clear transmission rights; the absence of secondary markets in transmission service; and the possible disincentives created by the level and structure of transmission rates. The Commission believes that properly structured RTOs can address both sets of problems and further the development of competitive bulk power markets.

a. Reliable Grid Operations

The United States has one of the most reliable power systems in the world. For over thirty years, NERC and the regional reliability councils have developed and implemented voluntary standards to maintain the security of the transmission systems. There is no net public policy benefit to promoting competition if reliability suffers as a consequence.[58] The promotion of competition must therefore go hand-in-hand with the creation of new institutions to ensure that reliability is maintained or improved in any new industry structure.[59] We fully agree with the findings of the DOE Reliability Task Force:

> * * * there is a critical need to be sure that reliability is not taken for granted as the industry restructures, and thus does not "fall through the cracks." [60]

The DOE Reliability Task Force also pointed out that with the entry of many new participants, dramatic increases in unbundled power sales and shifts in electrical flows, the nation's bulk power system is being stressed in ways that have never been experienced before. A similar conclusion was reached by NERC in its 1998 summer assessment of bulk power reliability:

> Throughout the Regions, parallel path flows from increased electricity transfers are stressing the transmission systems. These flows are at magnitudes and in directions not anticipated at the time the systems were designed.* * *The transmission system will be required to operate under unprecedented, and sometimes unstudied, conditions.[61]

These stresses have always existed but not in these magnitudes. Moreover, they could be more readily accommodated through voluntary ad hoc agreements when there were fewer industry participants who generally did not compete against each other in any significant way.[62] But as we have noted, this traditional industry structure is rapidly disappearing. Our concern is that the reliability fault lines may become more prominent and dangerous.

It is well accepted that the operation of interconnected transmission networks requires careful coordination and the exchange of information between many individual systems. Any operational change on one system in the network instantly affects other systems. For example, the shipment of power from one location to another will divide among all transmission paths from source to destination based on the laws of physics.[63] This is referred to as

[54] North American Electric Reliability Council, Electric Reliability Panel, "Reliable Power: Renewing the North American Electric Reliability Oversight System," December 1997, at 9.

[55] U.S. Congress, Office of Technology Assessment, "Electric Power Wheeling and Dealing, Technological Considerations for Increasing Competition," May, 1989.

[56] For example, there are now about 550 Commission-approved power marketers. Decentralization has also increased because of divestiture of generating plants by traditionally vertically integrated utilities. Such sales are frequently required by state governments as one element of the structural reforms that accompany the introduction of retail competition. During the last three years, utilities have sold or have contracts to sell more than 50,000 MW of existing generating capacity. About 30,000 MW of additional capacity is currently being offered for sale.

[57] *See* definition of ATC *infra*.

[58] Unless otherwise noted, we use the term "reliability" to refer to the reliable or secure operation of the bulk power grid. This is one component of the broader NERC definition, which also includes "adequacy" (i.e., sufficient generation and transmission capacity) as a second component of overall reliability. *See* North American Electric Reliability Council, "Glossary of Terms," August 1996, at 21.

[59] *See* George C. Loehr, "Ten Myths About Electric Deregulation: Electrons May Seem Imaginary, But Reliability Is Real," Public Utilities Fortnightly, April 15, 1998, at 28–31.

[60] DOE Task Force Report, at xv.

[61] NERC, "1998 Summer Assessment: Reliability of Bulk Electricity Supply in North America," May 1998, at 2–3.

[62] In assessing the continued viability of the current system, NERC's blue-ribbon Electric Reliability Panel concluded that: "The competitive dynamics among a much larger universe of players is not at all conducive to a system of voluntary peer compliance." Electric Reliability Panel Report, December 1997, at 28.

[63] The amount of power flowing on any path in an electrical network is inversely proportional to that path's impedance. Impedance will depend on the actual length of the line and its voltage. *See* U.S. Congress, Office of Technology Assessment, Electric

parallel path or loop flow. Such flows will also affect a neighboring system's ability to determine ATC accurately. In addition, if a transmission facility is already loaded close to its operating limit, the additional flow resulting from a transaction contracted for on a neighboring system may overload the facility and threaten reliability. In order to operate the system in a reliable manner, a single, independent grid operator must know all sources and destinations for each transaction. The Commission believes that an RTO, as the only transmission provider and security coordinator in its region, would have the information needed to identify the effects of parallel flows and accommodate them in its operations.

At present, the industry's ability to maintain reliable grid operation is hindered by the existence of many separate organizations that directly or indirectly affect the operation and expansion of the grid. There are more than 100 owners of the Nation's grid who operate about 140 separate control areas.[64] In addition, there are 10 regional reliability councils, 23 security coordinators, 5 regional transmission groups (RTGs) and 5 independent system operators. With so many entities, the lines of authority and communication are not always as clear as they should be.[65] An additional complication is that many of these entities also own generation or have a decision making process that continues to be dominated by traditional vertically integrated utilities.[66] Therefore, their independence and commercial neutrality as grid operators is subject to question.

It appears that information that is critical for maintaining reliability is not being shared as readily now as was generally the case in the past. NERC recently observed that there is a growing "reluctance on the part of the market participants to share operational real-time and operational planning data with TPs [transmission providers]." [67] This is not surprising because, as we have noted before, information that is needed for reliability purposes may also have a commercial value.[68] If market participants believe that the entity that receives operational information for reliability reasons may use it for commercial advantage, they will understandably be reluctant to supply the information. After spending more than 18 months reviewing the current reliability system, the DOE Reliability Task Force concluded that this inherited system, with its patchwork of organizations, inadequate information sharing and overlapping and sometimes unclear responsibilities, is "clearly unsustainable" and that until new policies and institutions are in place, "substantial parts of North America will be exposed to unacceptable risk." [69]

This is not just a theoretical concern. During last year's regional ISO conferences, several industry participants described three "reliability near misses" in the Midwest. The three incidents on July 22, 1993, August 7, 1996 and July 11, 1997 came very close to producing major outages throughout the Midwest.[70] While there has been some improvement in coordination among different systems, we believe that there are limits to the amount of coordination that can be achieved between separate organizations, especially if they are competing for the right to use the same limited transmission capacity and sometimes competing for the same customers. While competition requires decentralization, we think that reliable and efficient grid operation requires more coordination. The Commission believes that a beneficial platform for both competition and reliability is a single independent grid operator that sees the "big picture" by having access to real-time information on conditions and schedules for the entire regional grid.[71] Such an entity does not exist in several regions of the country. As a consequence, there is, at present, a disconnect between electrical flows and information flows that could have major reliability consequences.

b. Determining Available Transmission Capability (ATC)

Any transportation service provider should know how much commodity it can carry. For electric transmission service providers, the calculations of total transmission capability (TTC) and ATC are needed to make this determination. TTC and ATC are key elements of the OASIS information system.[72] Order No. 889 requires each transmission provider to calculate and post TTC and ATC numbers to give its transmission customers a reasonable estimate of how much power can be carried between any two locations on the grid and how much capacity is available to support additional trade at any given time.

We have received many complaints about the accuracy and usefulness of posted ATC numbers. There are several reasons why it is difficult to determine available transmission capability accurately.

First, ATC numbers are still calculated on an individual company basis in many areas of the country. Separate calculations of ATC by individual companies are fundamentally inconsistent with the physical reality of an interconnected transmission system. An individual transmission provider may post ATC numbers in good faith, and attempt to provide transmission service based on these numbers, only to learn later that the transfer capability that it thought was available no longer exists because of decisions made by other transmission providers that it did not know about at the time it made its calculations. Accurate ATC numbers would require reliable and timely information about load, generation, facility outages and transactions on neighboring systems. Individual transmission operators will generally not have this information. They also may apply differing assumptions and criteria to ATC calculations, which may produce wide variations in posted ATC values for the same transmission path.[73] All these considerations make it virtually impossible for an individual transmission provider that operates one

Power Wheeling and Dealing: Technological Considerations for Increasing Competition, OTA-E-409, May 1989, at 110-11.

[64] A control area is an electrical system bounded by interconnection (tie-line) metering and telemetry. Within a control area, resources are balanced against load, and generation is regulated to maintain interchange schedules with other control areas and to achieve the target frequency (60 hz) for the entire Interconnection. *See* NERC Operating Policies Manual (available on the NERC website at www.nerc.com).

[65] *See, e.g.*, Western Systems Coordinating Council, EL99-23-000, comments of Enron Power Marketing, Inc. at 4-5.

[66] *See, e.g.*, New England Power Pool, 86 FERC ¶ 61,262 at 61,965 (1999).

[67] NERC, Reliability Assessment 1998-2007 at 39 (1998).

[68] *Midwest ISO*, 84 FERC at 62, 158-159.

[69] DOE Task Force Report at vii and xi.

[70] Regional ISO Conference (Indianapolis), transcript at 24-29.

[71] The importance of a single operator for reliability was stressed in comments of AMEREN and Commonwealth Edison. *See* Regional ISO Conference (Indianapolis), transcript at 19-29.

[72] ATC is a measure of transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. TTC is the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner based on certain specified conditions. North American Reliability Council, Glossary of Terms (1996).

[73] This, in turn, creates other problems. According to NERC, the "inconsistent calculation [of ATC] can increase the use of TLR and other operational complexities, which has the potential to cause reliability problems." NERC, Reliability Assessment, 1998-2007, September, 1998, at 40. (*See* definition of TLR in section II.)

part of a large interconnected grid to calculate ATC accurately.[74]

Second, requests for transmission service are usually based on "contract path" scheduling. This is the practice of finding a contiguous chain of utilities from the power supplier to the power consumer and contracting with those utilities to transmit the power. The implicit assumption is that all the power flows through the utilities along this "contract path." In fact, the power divides up and flows along all paths from the supplier to the buyer. All utilities in the region are affected. Contract path scheduling provides little or no information about actual flows on the grid.[75] In its October 1997 report to the Commission, the Commercial Practices Working Group commented that: "Reserving and scheduling transmission on a contract path basis does not even closely resemble the physical impact on the system." [76] We note that NERC is encouraging initiatives that would move the industry toward recognizing actual flows in scheduling.[77]

c. Managing Congestion

Congestion occurs when requests for transmission service exceed the capability of the grid. When transmission constraints limit the amount of power that can be transmitted, the loads on the system may not be able to be served by the least-cost mix of available generators. The constraints may reflect voltage, temperature and dynamic limits. Relieving congestion leads to a more costly pattern of generation dispatch. The cost of congestion is the additional energy cost associated with the new pattern of dispatch.

We recognize that even optimally designed systems will normally experience at least occasional congestion that at times can be significant and costly. In general, congestion can be managed in two ways: the construction of new transmission facilities that increase grid capacity; or the redispatch of existing or new generators to reduce flows or create counterflows on the constrained facility. The complete elimination of congestion would typically require the construction of new transmission facilities. While this may be a physically effective solution, it may not always be cost effective. Because of this, we believe that an efficiently operated transmission system should have in place mechanisms for pricing congestion and then managing congestion through changes in the pattern of dispatch. Without mechanisms for determining the cost of congestion, it will be virtually impossible to make rational, cost effective decisions to expand the grid.

The Commission believes that efficient congestion management is best performed at the regional level. At present, outside of the operational ISOs, transaction curtailment through transmission loading relief (TLR) procedures is the dominant approach for dealing with congestion in the Eastern Interconnection. NERC has reported that its TLR procedures were invoked 329 times between July 1997 and October 1998 on the Eastern Interconnection.[78] Current TLR procedures are cumbersome, inefficient and disruptive to bulk power markets because they rely exclusively on physical measures of flows with no attempt to assess the relative costs of different congestion management options. Moreover, TLR actions are typically taken by one utility without assessing the costs imposed on other grid users. This inevitably raises the suspicion that the TLR request could be motivated by competitive rather than reliability concerns. For these reasons, the Commission has encouraged NERC to develop regional market approaches to managing congestion.[79]

The Commission recognizes, however, that NERC may not be able to comply fully with this policy in the absence of regional organizations that have the authority and ability to promote regional congestion markets. There are three considerations that support this conclusion.

First, a regional organization would have accurate and reliable information about existing and possible future conditions on the grid. Such information is generally not available to individual transmission providers. RTOs would have this information because they would function as both regional security coordinators and regional transmission providers.

Second, congestion management is best performed at a regional level. This is shown in the largely unsuccessful efforts of Commonwealth Edison to create congestion markets that would allow transmission customers to "buy-through" (*i.e.*, firm up) transmission rights on congested flow gates. After six months of its one year experiment, we note that Commonwealth concluded that it is "difficult for one transmission owner to identify and implement redispatch" when the physical limitations and cost effective options for relief exist on other transmission systems that are beyond their reach.[80]

Third, RTOs will be able to establish and define rights to the use of the grid. At present, with multiple and independent operators of the grid, individual users and owners have unclear and conflicting rights to the grid. This makes it difficult to establish congestion markets. A congestion market, like any other market, cannot develop in the absence of clear rights.[81] Such rights, whether held by transmission users or owners, are a necessary prerequisite for establishing congestion markets. Without establishing such rights, the industry will continue to grapple with the problem of incomplete markets. Thus, it is difficult to achieve efficient and competitive regional bulk power markets if congestion on the transmission grid is not accurately priced.

d. Planning and Expanding Transmission Facilities

Transmission planning and expansion are more difficult today than three years ago. While uncertainty has always been a fact of life for any transmission planning exercise, the level of uncertainty has increased with the increasing number and distance of unbundled transactions and the wider variation in generation dispatch patterns. Uncertainty has also increased because:

> Generation developers are reluctant to disclose their plans for future capacity additions. Similarly, utilities intending to purchase from others are reluctant to speculate on whom or where their suppliers might be, making modeling of such transactions for transmission analysis virtually impossible.[82]

One troubling consequence of this uncertainty has been a noticeable decline in planned transmission investments. NERC recently reported that the level of planned transmission

[74] In addition, it has been frequently alleged that individual transmission may intentionally post inaccurate ATC numbers to favor their own power marketing efforts. These allegations are discussed in section III.A.2.

[75] *See* Allegheny Power Service Corporation *et al.*, 78 FERC ¶ 61,314 at 62,339.

[76] October 31, 1997 report, at 39.

[77] *See NERC*, 85 FERC at 62,363.

[78] North American Electricity Reliability Council, Interim Market Interface Committee, Minutes of Jan. 12 and 13, 1999 meeting, Exhibit D.

[79] *See NERC*, 85 FERC at 62,364.

[80] Commonwealth Edison, Interim Report on Non-Firm Redispatch, Docket No. ER98-2279, December 17, 1998, at 4, 10.

[81] Robert Cooter and Thomas Ulen, Law and Economics, Scott, Foresman and Company, 1988, at 91 ("From a legal viewpoint, property is a bundle of rights").

[82] NERC, "Reliability Assessment, 1998-2007," September 1998, at 39.

additions is significantly lower than five years ago despite an overall increase in load growth and unbundled transmission service.[83] While this could simply reflect better utilization of the existing grid, the Commission is concerned that it may also reflect an incompatibility of existing planning institutions with the new market realities.

We are also concerned that the existing approach to transmission pricing may not sufficiently encourage the investments in transmission facilities that are needed to improve the reliability and efficiency of the grid. Inadequate investment could be a major impediment to the development of regional bulk power markets and a possible source of future reliability problems. There are at least three concerns about the way transmission prices are set.

First, although there are varying degrees of investment coordination around the country, utilities ultimately make transmission investment decisions individually rather than through joint decisions that internalize commercial and reliability effects of the investment. It may be unclear which utility should have the responsibility for expanding capacity to relieve a transmission constraint. For example, power flows scheduled by one utility with ample transmission capacity on its own lines may overload a neighbor's lines. The first utility may be unwilling to expand transmission capacity because it needs no extra transmission capacity itself, and the second utility may be unwilling to expand transmission capacity because it collects no revenues from the power flows scheduled by others. In a multi-utility region, decisions about where to site new facilities and who should pay for capacity expansions can be even more complex unless a regional body provides a forum for discussions and a method for resolving disputes.

Second, the motivation for constructing new facilities is changing as the industry changes. Formerly, a utility built transmission primarily to deliver power from its generating plants to its customers. Inadequate transmission would have hurt power sales, the principal source of utility revenue. Today, facility expansion may be needed to transmit power sold by others. As generation and transmission ownership become increasingly separate and as many states implement or even merely consider retail access, the transmission owner's traditional incentive for making new transmission investment to support its power sales erodes. Incentives for transmission investment need to be related more to the power needs of the region than the generation stock of the transmission owners.

Third, the transmission owner that does invest in transmission to overcome a constraint may be concerned about recovering its investment. Under traditional ratemaking practices, it must recover its investment over a long period of time, typically thirty years. But subsequent generation construction on the power-poor side of the constraint may obviate the need for the line and threaten recovery of its capital cost. In addition, where there is higher risk, a higher return commensurate with the higher risk may be appropriate. To support this, customers and regulators would want assurance that the decision to invest in transmission is made in the best interests of the region, considering not only all the transmission options but also the generation and demand management alternatives to transmission construction. Therefore, as discussed below, we will consider concrete proposals from regional transmission organizations for transmission pricing reforms and the explicit use of pricing incentives to encourage RTOs to make efficient investments in new transmission facilities.

e. Pancaked Transmission Rates

With the exception of power pools, open access under Order No. 888 focuses on individual, existing transmission providers. Order No. 888 does not require transmission pricing reforms that are needed to support efficient and competitive bulk power markets. The "missing" reforms include, among others, the elimination of pancaked transmission access charges, the use of reservation-based (as opposed to load-based) transmission tariffs and the availability of secondary markets in transmission rights.[84] In this section, we will focus on the problems created by the widespread pancaking of transmission access charges.[85]

In most of the United States, a transmission customer pays separate, additive access charges every time its contract path crosses the boundary of a transmission owner. By raising the cost of transmission, pancaking reduces the size of geographic power markets. This, in turn, can result in concentrated electricity markets. Balkanization of electricity markets hurts electricity consumers, in general, by forcing them to pay higher prices than they would in a larger, more competitive, bulk power market.[86]

The Commission has heard from many states about the negative effects of pancaked rates in their efforts to introduce retail competition. At this time, about 21 states have introduced or are planning to introduce competition for retail loads under their jurisdiction.[87] Because the Commission has jurisdiction over transmission service and rates for unbundled retail customers, we have an obligation to address these concerns.[88] A retail choice initiative, no matter how well designed at the state level, may fail if the pool of potential competitors is effectively limited to a few nearby supply sources because of pancaked transmission charges.

This concern of pancaked rates was highlighted to us in the recent consultations with our state commission colleagues. Several state commissioners emphasized that the success of their retail competition initiatives is related to the adoption of non-pancaked transmission tariffs and other ISO policies.[89] We believe that the likelihood of success for existing and planned retail choice initiatives is significantly enhanced if the Commission can ensure fair and efficient access to a regional market without pancaked transmission access charges, and that we need to take steps beyond Order No. 888 to accomplish this.

f. Conclusion

We believe that the preferred solution to the engineering and economic problems discussed in this section is a regional solution. Notwithstanding it success, Order No. 888 has not been able to produce a fully efficient and competitive outcome because it does not address ATC calculations, congestion

[83] *Id.* at 7.

[84] *See, e.g.*, Capacity Reservation Open Access Transmission Tariffs, Notice of Proposed Rulemaking, FERC Stats. and Regs. ¶ 32,519 (1996) and Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act: Policy Statement, 69 FERC ¶ 61,086 (1994).

[85] We did, however, require non-pancaked rates for power pools that offer non-pancaked rates to their own members in Order No. 888. *Order No. 888*, FERC Stats. and Regs. at 31,727–28.

[86] While it is difficult to estimate the exact impact on consumers, we note that there have been studies of the deregulated British power markets that have found excessive concentration in generation has produced prices 20 to 40 percent above competitive levels at certain times. Richard Green and David Newbery, *Competition in the British Electricity Spot Market*, 100 J. Pol. Econ., 929, 1992.

[87] "Status of Electric Utility Deregulation as of May 1, 1999," Energy Information Administration.

[88] *Order No. 888*, FERC Stats. and Regs. at 31,651–52.

[89] *See, e.g.*, Comments of Gerald Thorpe (Maryland) and President Herbert Tate (New Jersey), RTO Conference (Washington, DC), transcript at 37–39; 49–51.

management, reliability, pancaking of transmission access charges, and grid planning and expansion. These are regional problems. Therefore, we are proposing a rule to encourage the development of independent regional transmission operators that can promote both electric system reliability and competitive generation markets.

2. Actual and Perceived Discriminatory Conduct by Transmission Owners to Favor Their Own or Affiliated Merchant Operations

In addition to operational inefficiencies impeding full competition, there also exist questions about residual discrimination in the provision of transmission services by public utilities. As discussed below, many in the industry have expressed a fundamental mistrust of transmission owners. In addition, there are allegations, and in some circumstances findings, of actual discrimination by transmission owners. We discuss below indications of discriminatory conduct by vertically integrated utilities and seek further comment on utility practices subsequent to Order No. 888.

Utilities that control monopoly transmission facilities and also have power marketing interests[90] have poor incentives to provide equal quality transmission service to their power marketing competitors. It is, in fact, in the economic self-interest of transmission-owning utilities to favor their own power marketing interests and frustrate their competitors. As the Commission stated in Order No. 888:

> It is in the economic self-interest of transmission monopolists, particularly those with high-cost generation assets, to deny transmission or to offer transmission on a basis that is inferior to that which they provide themselves. The inherent characteristics of monopolists make it inevitable that they will act in their own self-interest to the detriment of others by refusing transmission and/or providing inferior transmission to competitors in the bulk power markets to favor their own generation, and it is our duty to eradicate unduly discriminatory practices.[91]

The exercise of transmission market power allows transmission providers with power marketing interests to benefit in the short-run by making more power sales at higher prices, and benefit in the long-run by deterring entry by other market participants. As a result, prices to the Nation's electricity consumers will be higher than need be.

It was to eliminate this inherent tendency of a vertically-integrated utility to favor its own power sales that Order Nos. 888 and 889 required utilities to functionally unbundle their transmission and power merchant services. Generally, functional unbundling requires a public utility to: separate its transmission system functions and staff from wholesale generation marketing functions and staff; abide by a standard of conduct to define impermissible contact between generation and transmission personnel; take transmission services under the same open access tariff of general applicability as do others; state separate rates for wholesale generation, transmission, and ancillary services; and rely on the same Open Access Same-Time Information System (OASIS) that its transmission customers rely on to obtain information about its transmission system when buying or selling power.[92] The Commission imposed these requirements to establish a foundation for open grid access and competitive electricity markets.

Functional unbundling did not change the incentives of vertically-integrated utilities to use their transmission assets to favor their own generation, but instead attempted to reduce the ability of utilities to act on those incentives. In Order No. 888, the Commission received and considered numerous comments that functional unbundling was unlikely to work, and that more drastic restructuring, such as corporate unbundling, was needed.[93] However, the Commission decided at the time to adopt what it considered to be the less intrusive and less costly remedy.

Clearly, Order No. 888 has resulted in wholesale power markets becoming more competitive, more transmission services being made available to more potential users than ever before, and generally lower transaction costs.

However, market participants increasingly have alleged that numerous transmission service problems related to discriminatory conduct remain, and that these problems are impeding competitive wholesale power markets.[94] Our information about alleged continued discriminatory practices comes from several sources. These include formal complaints filed with the Commission, informal complaints made to the Commission's enforcement hotline, oral and written comments made in conjunction with public conferences held by the Commission, and pleadings filed with the Commission in various dockets.

Compared to the situation before Order No. 888, transmission-owning utilities must now resort to more subtle means to frustrate their marketing competitors and favor their own marketing interests. Continued discrimination may be conscious and deliberate, but it may also result from the failure to make sufficient efforts to change the way integrated utilities have done business for many years. In either case, the tendency of transmission owners to confer advantages, however subtle, upon their own marketing interests is discriminatory as against other marketers.

In the sections that follow, we will outline the information derived from filings and other sources about remaining impediments to competition caused by continued discriminatory conduct by transmission owners. We note, and we are well aware, that many allegations that have been made in various forums are unproved, and perceived discrimination may in fact turn out to have justifiable explanations. It is often hard to determine, on an after-the-fact basis, whether an action was motivated by an intent to favor affiliates or simply resulted from the need to serve native load customers or the impartial application of operating or technical requirements. Given our considerable difficulty in determining whether there has been compliance with our regulations, the question arises whether functional unbundling is an appropriate long-term regulatory solution.

We consider allegations of discrimination, even if not reduced to formal findings, to be a serious concern for two reasons. First, we may be seeing only the "tip of the iceberg." We are aware that instances of actual discriminatory conduct may be undetectable in a non-transparent market. In addition, there are significant disincentives to filing and pursuing formal complaints that would result in definitive findings. Transmission customers often tell the Commission's enforcement staff that they are reluctant to make even informal complaints because of concerns that the Commission will not take strong action, and fear, perhaps most importantly, of retribution by their transmission supplier.[95] We also have been told that

[90] The term power marketing interests is used as shorthand herein to include the utility's own wholesale merchant function as well as any affiliates with wholesale merchant functions.

[91] *Order No.* 888, FERC Stats. and Regs. at 31,682.

[92] *Id.* at 31,654–55.

[93] *Id.* at 31,653–54.

[94] *See, e.g.*, of Roger Fontes on behalf of the Northern California Power Agency, Regional ISO Conference (Phoenix), Transcript at 136 ("In general, orders 888 and 889 have not fully remedied undue discrimination in providing transmission service in this country.")

[95] *See* Comments of Dan Jones on behalf of the Public Utilities Commission of Texas, Regional ISO

the complaint process is costly and time-consuming,[96] and that the Commission's remedies for transmission violations do not impose sufficient financial harms on the transmission provider to act as a significant deterrent.[97]

Perhaps the most problematic aspect of relying on after-the-fact enforcement in the fast-paced business of power marketing, however, is that there may be no adequate remedy for lost short-term sale opportunities. For example, the Electric Power Supply Association has told us:

> Furthermore, even if the exercise of such discrimination could be adequately documented and packaged in the form of a complaint under Section 206 of the Federal Power Act under a more streamlined complaint process contemplated by the Commission, it would still be extremely costly and inefficient to deal with such complaints on a case-by-case basis. More than likely, the potential power transactions for which transmission principally was sought would disappear by the time a Commission ruling was obtained.[98]

Accordingly, actual problems with functional unbundling may be more pervasive than formally adjudicated complaints would suggest, and the informal allegations we hear provide valuable insight.

Second, we consider the allegations of discrimination to be serious because, if nothing else, they represent a *perception* by market participants that the market is not working fairly because such participants know that integrated utilities have the incentive and opportunity to discriminate. Mistrust in the market can itself be a serious impediment to competition. If market participants perceive that other participants have an unfair advantage through the affiliation with the transmission provider, it can inhibit their willingness to participate in the market, including, for example, building new generating units, thus thwarting the development of robust competition. Such mistrust can also harm reliability. As stated by NERC, there is a reluctance on the part of market participants to share operational real-time and planning data with transmission providers because of the suspicion that they could be providing an advantage to their affiliated marketing groups.[99]

The functional unbundling policy underlying Order No. 888 was an attempt to regulate the behavior of transmission owners. There are growing indications, however, that the conflicting incentives that vertically integrated utilities have regarding transmission access may be too difficult to police. Many have asserted that it is not realistic even to expect functional unbundling to eliminate attempts by transmission owners to gain economic advantage. Companies have an obligation to maximize value for shareholders, and it should be no surprise that they will be aggressive in doing so. For example, in comments to the Commission in the Order No. 888 proceeding, the Federal Trade Commission advised the Commission that a functional unbundling approach "* * * would leave in place the incentive and opportunity for some utilities to exercise market power in the regulated system. Preventing them from doing so by enforcing regulations to control their behavior may prove difficult." A representative of Lafayette Utilities told us at the New Orleans ISO Conference:

> Notwithstanding functional separation and the requirement not to discriminate, transmission personnel are well aware of the interests of their company's generation function, and can find a way to give preferential treatment. * * *[100]

A representative of a Wisconsin public utility told us:

> Administration of the tariff entails a myriad of decisions that require discretion, as well as "technical" judgments (like [available transmission capability] and [capacity benefit margin]) that have significant competitive ramifications. It is inevitable that these decisions and judgments will be made with competitive concerns in mind. Functional separation does not solve this problem.[101]

Similarly, at our regional ISO conference in Indianapolis, we were told:

> In a capital intensive industry where a high percentage of the investment is in generation assets, it is inconceivable that a utility, which in some cases has very high generation cost, would somehow manage its transmission system so as not to give its generation a competitive advantage. I think this is self-evident.[102]

While it should not be assumed that such problems exist in every circumstance, clearly many market participants do not believe the market can yet be trusted with respect to their commercial interests, at least in some areas. We now turn to some of the areas that have produced the most complaints about continuing discrimination.

a. Calculation and Posting of Available Transmission Capability in a Manner Favorable to the Transmission Provider

Perhaps the most significant complaint with respect to alleged discriminatory conduct under functional unbundling concerns the important function of calculating and posting the amount of transmission capability that is available on a transmission provider's system. The transmission provider is required to calculate and post on its OASIS the TTC and ATC for each posted transmission path.[103] ATC is the capacity that is stated to be available for transmission service requests. As we discussed above in Section III.A.1, it is not possible to calculate accurately the transmission capability of one system without knowing the flows scheduled by all other interconnected transmission providers in the region. Given this technical problem, it may be impossible to distinguish an inaccurate ATC presented in good faith from an inaccurate ATC presented for the purpose of favoring the transmission provider's marketing interests.

Transmission providers with power marketing interests have incentives to understate ATC on those paths valuable to its marketing competitors, or to divert transmission capacity so that it is available for use by its own marketing interests. If there is insufficient ATC, competitors may be forced to forego power sale transactions or use a less desirable alternative path if one is available.

The Commission has found violations of ATC postings in three cases. In *Washington Water Power Company*,[104] the transmission owning utility showed that it had no firm ATC, which would have discouraged any potential marketers who needed firm transmission service to make a sale. However, the utility then offered its power marketing affiliate, Avista

Conference (Kansas City), Transcript at 1985 ("And we've also heard that these entities are hesitant to bring those complaints forward because they have to deal with both sides of that utility").

[96] We note that we have recently issued a Final Rule regarding complaint procedures designed to make them more efficient. *See* Complaint Procedures, Final Rule, Docket No. RM98-13-000, 86 FERC ¶ 61,324 (issued March 31, 1999).

[97] Comments of National Energy Marketers Association, Docket No. RM98-5-000 (filed January 22, 1999).

[98] Motion to Intervene and Comments of Electric Power Supply Association in Support of Petition for Rulemaking, Docket No. RM98-5-000 (filed Sept. 21, 1998), at 3.

[99] NERC Reliability Assessment 1998-2007, at 39.

[100] Comments of Frank Ledoux on behalf of Lafayette Utilities System, Regional ISO Conference (New Orleans), Transcript at 180.

[101] Statement of Roy Thilly on behalf of Wisconsin Public Power, Inc. at 2, Docket No. PL98-5-000 (filed April 15, 1998).

[102] Comments of Kenneth Hegemann on behalf of American Municipal Power, Ohio, Regional ISO Conference (Indianapolis), Transcript at 174.

[103] *See* 18 CFR 37.6(b) (1998).

[104] 83 FERC ¶ 61,097 (1998), *further order*, 83 FERC ¶ 61,282 (1998).

Energy, an "interruptible firm" transmission service that was not available to competitors. As the Commission explained in finding a violation of Order No. 888:

Avista received a preference from Washington Water Power that was not available to any of its competitors. Simply stated, Avista's customer was deprived of the benefit of choosing among all potential power suppliers.

The case of *Wisconsin Public Power Inc. SYSTEM* v. *Wisconsin Public Service Corporation, et al.* (*Wisconsin Public*) [105] demonstrates both the difficulties and suspicions of discrimination resulting from when a transmission customer requests transmission service from an integrated utility. WPPI was seeking additional network transmission service from both Wisconsin Public Service Corporation (WPSC) and Wisconsin Power & Light Company (WP&L). In both cases, the requests were denied because of claims that the transmission owners were using all available capacity. In the case of WPSC, the Commission initially found that the utility had not properly reserved capacity for its merchant function and directed that it recompute its ATC without that reservation. After WPSC submitted additional documentation, the Commission accepted some of WPSC's merchant priority, but still found that it had violated its obligations under its tariff, and that its actions raised serious concerns about the functional separation of its staff. With respect to WP&L, the Commission found that it provided unduly preferential treatment to its merchant function, had been changing its ATC without posting those changes on OASIS, and had been computing ATC where none exists.[106]

The *Wisconsin Public* cases demonstrate, if nothing else, the difficulty of achieving, and enforcing, functional separation of a utility's transmission and merchant functions. These types of cases require substantial Commission investigative and adjudicative resources, not to mention the resources of the parties involved. The Commission recognized in *Wisconsin Public* how RTOs could help eliminate these problems. The Commission stated:

As we recently explained in *Louisville Gas & Electric Company, et al.*, 82 FERC ¶ 61,308 at 62,222 & n. 39 (1998), a properly structured ISO, or other transmission entity can eliminate the potential for the strategic use of a transmission owner's priority to use internal system capacity for native load. The ISO or other transmission entity can also eliminate the incentive to engage in strategic curtailments of generation that a transmission operator's generation service competitors own and can remove any incentive to game OASIS operations. This will promote generation entry and competition, since a properly structured ISO or other transmission entity would have no economic stake in favoring certain market participants over others and potential entrants would likely see the transmission market as fair. An ISO, therefore, could help to solve the problems established in the instant complaints.[107]

The case of *Morgan Stanley Capital Group* v. *Illinois Power Company*[108] also demonstrated problems associated with ATC and a transmission provider's use of its system for its own purposes. Morgan Stanley complained that Illinois Power failed to accurately post ATC, failed to award transmission capacity in a non-discriminatory manner, and allocated transmission in favor of its own bulk power marketing arm. Illinois Power admitted the ATC posting error, and the Commission found other violations of its tariff in responding to Morgan Stanley's request for service. Although the Commission initially also found that Illinois Power did not designate its own network resources in the same manner as network customers are required to designate them, Illinois Power disputed this, and after showing that its network resource was legitimate, the Commission dismissed its rehearing as moot. Nevertheless, this case demonstrates that a combination of ATC errors and unclear procedures feeds the mistrust in the marketplace with respect to a transmission owner's ability to use its system to favor itself.

We also have currently pending before us several formal complaints alleging that a transmission provider is improperly keeping its transmission capability for its merchant function. In one case, a power marketer asserts that a transmission provider has refused service over an interconnection on the basis that the transmission provider needs all the ATC for native load. The marketer has alleged that the transmission provider's claims of reliability concerns are a mask to block competitors from importing power into the transmission provider's system when the transmission provider has higher cost generation available.[109] In another recent formal complaint filing, it is alleged that a transmission provider denied transmission service and then improperly provided it to its merchant group.[110]

Aside from these cases involving formal complaints, there have been a number of other complaints with respect to ATC calculation. For example, our enforcement staff receives hotline complaints concerning ATC posting problems. The enforcement staff has confirmed a number of such ATC errors. In most cases, these errors were corrected within several months of having them pointed out, and the utilities often offered explanations based on hardware or software problems. We make no judgment whether such identified errors were an intentional attempt to thwart competition; however, they had the potential to have that effect.

In July 1997, the Commission held a technical conference concerning how well the OASIS system was working. Several commenters suggested that erroneous ATC calculation and posting was hurting competition. A representative from Electric Clearinghouse told us that there is a pervasive problem of incorrect or stale information on the OASIS sites, and that "competition is blocked when this occurs." That same representative stated that very little firm ATC is offered due to the utility's caution or strategy, and that some providers will not offer firm ATC because they do not want to curtail their own transactions.[111] At the same conference, a representative from the American Public Power Association told us:

ATC is often understated and inconsistently posted on adjacent OASIS nodes. Inter-regional coordination is lacking. This fact limits the usefulness of the system for commercial purposes.[112]

In March 1998, a group referring to themselves as power industry stakeholders[113] filed a petition for rulemaking on electric power industry structure.[114] Although we are not addressing here the specific relief they are requesting in that Petition, the

[105] 83 FERC ¶ 61,198 (1998), *order on reh'g*, 84 FERC ¶ 61,120 (1998).

[106] 83 FERC at 61,860.

[107] *Id.* at 61,859.

[108] 83 FERC ¶ 61,204, *order granting clarification and dismissing reh'g*, 83 FERC ¶ 61,299 (1998).

[109] Aquila Power Corporation v. Entergy Services, Inc., Docket No. EL98-36-000, Amended and Restated Complaint at 6 (filed June 23, 1998).

[110] Arizona Public Service Company v. Idaho Power Company, Docket No. EL99-44-000 (filed March 3, 1999).

[111] Open Access Same Time Information Technical Conference, Docket No. RM95-9-003 (July 18, 1997), transcript at 23.

[112] *Id.* at 28.

[113] The group consists of a number of power marketers and users, including, for example, Coalition for a Competitive Electric Market, ELCON, Electric Clearinghouse, Inc., and Enron Power Marketing, Inc.

[114] Petition for a Rulemaking on Electric Power Industry Structure and Commercial Practices and Motion to Clarify or Reconsider Certain Open-Access Commercial Practices, Docket No. RM98-5-000.

Petition does contain a number of fairly specific allegations indicating problems in the market. For example, the Petition asserts:

> Concepts such as ATC and the OASIS have become vehicles for obstructing and curtailing, rather than accommodating, transactions. Incumbents are able to deny new entrants access to critical, accurate information across control areas. This can take the form of out-of-date or incorrect postings of ATC or, in some instances, intentional withholding of actual ATC. Regardless of the cause, more transmission capability is physically available than is being released for sale.[115]

The Petition alleges the existence of "ATC exclusions, inaccuracies and misuses that deny new entrants the ability to evaluate market opportunities, and therefore, prevent reasonable access to the grid." [116] The Petition cited specific instances of inconsistent ATC calculations for the same interconnection by the systems on either side; an OASIS showing ATC that was not in fact made available for scheduling; and an OASIS showing no ATC but the utility then using that path for a sale.[117]

EPSA, the trade association representing certain power suppliers, filed comments in support of the Petition and echoed many of the same experiences:

> EPSA agrees that this discriminatory conduct persists principally because of the continuing incentives and opportunity for transmission owning public utilities covertly to discriminate against other transmission customers, by, for example, minimizing reported available transmission capability (ATC), delaying or inaccurately posting ATC on the OASIS, or otherwise manipulating market operations.[118]

EPSA further stated that, "The manipulation of ATC—whether with the intent to deceive or as the result of poor OASIS management—is a serious entrance barrier for competitive power suppliers." [119]

At our regional ISO conference in New Orleans, we were told by a representative from the Public Service Commission of Yazoo City, Mississippi, of a specific instance of what it considered to be discriminatory treatment:

> Yazoo City, as a participant, has experienced first hand an individual [transmission] owner's continued ability to use its ownership and control [of] transmission to disadvantage competitors, notwithstanding Order 888's mandate of non-discriminatory transmission access.

The representative then went on to describe an instance where a marketer could not complete a 10 MW power sale because of transmission restrictions, but then the transmission provider offered to supply the capacity itself.[120] The representative concluded that Orders Nos. 888 and 889 have not fully eliminated undue discrimination and this will not be achieved "as long as transmission owners are allowed to fence in transmission-dependent utilities and others located on their transmission system to enhance the value of their generation assets at increased cost to competitors."

One specific area where there have been allegations that transmission owners are using ATC to favor their own merchant operations concerns the calculation and use of Capacity Benefit Margin (CBM). Although there is no single accepted definition, CBM is generally used to mean an amount of transmission transfer capability reserved by load serving entities to ensure access to generation from interconnected systems to meet their generation reliability requirements.[121] Some utilities subtract CBM from their total transmission capability to arrive at ATC. There is no uniform method for calculating CBM. The ability to withhold CBM to ensure reliability not only confers a reliability advantage for the transmission provider, but may give the transmission provider the opportunity to selectively withhold ATC over paths and interconnections useful to its generation competitors.

The use of CBM is an issue that is currently being considered in several cases pending before the Commission.[122] For example, with respect to the formation of the PJM ISO, the Commission noted that it was not demonstrated that the PJM Pool's historical practice of withholding firm transmission interface capacity as a substitute for installed generating reserves is consistent with our open access policies. The Commission observed that the load serving entities that own generating capacity within the PJM control area appeared to benefit from this practice as suppliers in addition to benefitting as load serving entities.[123] The Commission set the issue for further briefing and it remains pending. In another pending proceeding concerning WPSC's CBM calculation, two of the parties assert that CBM "removes firm transmission capacity from open access offerings, thereby raising an unnecessary and unjustifiable barrier to competition," and "fosters discrimination by giving merchant functions gatekeeping control over CBM-related transmission access and by giving individual interface transmission owners broad discretion over where and how much CBM is withdrawn from ATC." [124] In the same proceeding, Electric Clearinghouse, Inc. asserts that "the CBM set-aside embodies undue discrimination in access to the monopoly owned transmission wires because it ensures certain users a priority over the reserved transmission interface capacity to the exclusion of other firm transmission users." [125]

As we stated above, we fully recognize that these are assertions made in pending cases in which we have not yet made findings. They are referenced here as illustrative of the suspicions in the industry of continuing opportunities for discriminatory treatment that may disadvantage certain competitors where generation owners continue to operate transmission.

b. Standards of Conduct Violations

To ensure the functional separation of a transmission provider's transmission and merchant functions, the Commission adopted standards of conduct that prohibit the transmission provider's marketing interest employees from having any more access to transmission system information than is available on OASIS, and requires the transmission provider's transmission employees to provide impartial service to all transmission customers.[126] If a transmission provider's marketing interests have favorable access to transmission system information or receive more favorable treatment of their transmission requests, this obviously creates a disadvantage for marketing competitors.

In spite of the standards of conduct, there continues to be a perception by

[115] Petition at 7–8.

[116] *Id.* at 15.

[117] *Id.* at Appendix D.

[118] EPSA Comments, Docket No. RM98–5–000, at 2 (filed September 21, 1998).

[119] *Id.* at 8.

[120] Comments of Robert D. Priest on behalf of the Public Service Commission of Yazoo City, Regional ISO Conference (New Orleans), Transcript at 201–03. After hearing this assertion, Entergy Services, Inc. filed a letter in which it stated that it was unable to identify any Entergy-imposed restrictions that would have prevented the power purchase. *See* Letter in Docket No. PL98–5–000 (filed July 1, 1998).

[121] NERC, Available Transfer Capability Definitions and Determinations (June 1996), at 14.

[122] The Commission recently noticed a technical conference, to be held May 20 and 21, 1999, on the issue of CBM. *See* Capacity Benefit Margin in Computing Available Transmission Capacity, Notice of Technical Conference, Docket No. EL99–46–000.

[123] *PJM*, 81 FERC at 62,277.

[124] Protest of Madison Gas & Electric Company and Wisconsin Public Power Inc., Docket No. EL98–2–003 at 3 (filed August 21, 1998).

[125] Protest of Electric Clearinghouse, Inc., Docket No. EL98–2–003, at 3 (filed Ausust 21, 1998).

[126] *See* 18 CFR Part 37 (1998).

many market participants that the transmission provider's marketing and transmission interests are not fully functionally separated. In cases in which the Commission has issued formal orders, we have found serious concerns with functional separation and improper information sharing with respect to at least four public utilities.[127] In addition, our enforcement staff receives numerous telephone calls about standards of conduct issues; some of these are simply questions about what is permissible conduct, but others are complaints of a violation. In a number of cases, our staff has verified non-compliance with the standards of conduct.[128]

The petitioners for rulemaking in Docket No. RM98-5-000 allege that there are common instances of "unauthorized exchanges of competitively valuable information on reservations and schedules between transmission system operators and their own or affiliated merchant operation employees." [129] They also cite OASIS data showing an instance where a transmission provider quickly confirmed requests for firm transmission service by an affiliate, while service requests from independent marketers took much longer to approve.

We believe that some of the identified standards of conduct violations are transitional issues resulting from a new way of doing business, and we acknowledge that many utilities are making good-faith efforts to properly implement standards of conduct. However, we also believe that there is great potential for standards of conduct violations that will never even be reported or detected. The use of standards of conduct is not the optimal procedure for ensuring a fair marketplace, and may be unnecessary in a properly structured and operated market.

We are increasingly concerned about the extensive regulatory oversight and administrative burdens that have resulted from policing compliance with standards of conduct. We have discussed above some of the cases in which the Commission had to address potential violations of the standards of conduct. In addition, transmission providers were required to file their standards of conduct for Commission review. In response, the Commission initially issued 8 orders concerning 126 public utilities' standards of conduct.[130] Generally, these orders required the utilities to revise their standards of conduct and post, on the OASIS, organizational charts and job descriptions for transmission/reliability and wholesale merchant function employees. The Commission subsequently issued 13 more orders requiring the public utilities to further revise their standards of conduct and/or organizational charts and job descriptions.[131] The Commission has also issued three orders on rehearing of the standards of conduct orders.[132]

As of April 1, 1999, 51 utilities' standards of conduct and organizational charts and job descriptions have been accepted and 75 utilities' standards of conduct and/or organizational charts and job descriptions have not been accepted and are pending review. This is an indication of the significant regulatory effort required by both public utilities and the Commission to make the standards of conduct approach workable—a regulatory effort that could be greatly reduced through more distinct organizational separation.

c. Line Loading Relief and Congestion Management

A number of complaints have been made alleging that transmission providers are acting in a discriminatory manner in implementing line loading relief, which is required when a transmission line is in danger of being overloaded. Such complaints allege that the transmission providers are not providing redispatch service, are favoring their own transactions, and are failing to follow curtailment priorities established in Order No. 888.[133] All of these actions by transmission providers may provide subtle competitive advantages in wholesale markets. For example, for those purchasers for whom service reliability is particularly important, purchasing power from a transmission provider may be viewed as offering enhanced reliability.

Like the issue of calculating ATC, the fact that curtailment of service in times of congestion is in the control of the transmission provider, who also has power transactions on the affected transmission lines, leads to suspicions of discriminatory behavior that are difficult to verify. For example, a representative of Blue Ridge Power Agency told us at one of our ISO conferences:

> There simply is no shaking the notion that integrated generation and transmission-owning utilities have strategic and competitive interests to consider when addressing transmission constraints. Functional unbundling and enforcement of [standard of] conduct standards require herculean policing efforts, and they are not practical. [134]

Likewise, we were told at another ISO conference that operators with reliability responsibility possess actual controlling authority over transactions, "thereby giving them a tremendous advantage over competitors." [135]

d. OASIS Sites That Are Difficult To Use

Aside from the problems alleged with respect to posting inaccurate ATC calculations on OASIS sites, there have been complaints that some transmission providers have implemented their OASIS sites as a tool to impede competition rather than as it was intended—as a tool to foster competition. It has been alleged that transmission providers have no incentive to make the sites easier to use, because it is primarily the transmission providers' marketing competitors who would benefit from better OASIS sites.[136] The petitioners in Docket No. RM98-5-000 asserted:

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[127] *See Wisconsin Public*, 83 FERC at 61,855, 61,860 (WPSC's actions raised "serious concerns" as to functional separation; WP&L's actions demonstrated that it provided unduly preferential treatment to its merchant function); *Washington Water Power*, 83 FERC at 61,463 (utility found to have violated standards in connection with its marketing affiliate); Utah Associated Municipal Power Systems v. PacifiCorp, 87 FERC ¶ 61,044 (1999) (finding that PacifiCorp had failed to maintain functional separation between merchant and transmission functions).

[128] *See, e.g.*, Communications of Market Information Between Affiliates, Docket No. IN99-2-000, 87 FERC ¶ 61,012 (1999) (Commission issued declaratory order based on hotline complaint clarifying that it is an undue preference in violation of section 205 for a public utility to tell an affiliate to look for a marketing offer prior to posting the offer publicly).

[129] Petition at 15.

[130] The citations for these orders are: 81 FERC ¶ 61,332 (1997), 81 FERC ¶ 61,338 (1997), 81 FERC ¶ 61,339 (1997), 82 FERC ¶ 61,028 (1998), 82 FERC ¶ 61,073 (1998), 82 FERC ¶ 61,132 (1998), 82 FERC ¶ 61,193 (1998) and 82 FERC ¶ 61,246 (1998).

[131] The citations for these orders are: 84 FERC ¶ 61,131 (1998), 84 FERC ¶ 61,255 (1998), 84 FERC ¶ 61,320 (1998), 84 FERC ¶ 61,327 (1998), 85 FERC ¶ 61,068 (1998), 85 FERC ¶ 61,145 (1998), 85 FERC ¶ 61,227 (1998), 85 FERC ¶ 61,390 (1998), 86 FERC ¶ 61,044 (1999), 86 FERC ¶ 61,079 (1999), 86 FERC ¶ 61,146 (1999), 86 FERC ¶ 61,185 (1999) and 86 FERC ¶ 61,246

[132] The citations for these orders are: 82 FERC ¶ 61,131 (1998), 83 FERC ¶ 61,357 (1998), and 85 FERC ¶ 61,382 (1998).

[133] We set for evidentiary hearing a formal complaint by Wisconsin Electric Power Company making these types of allegations. Wisconsin Electric Power Company v. Northern States Power Company (Minnesota) and Northern States Power Company (Wisconsin), 86 FERC ¶ 61,121 (1999). The parties subsequently filed a settlement agreement.

[134] Regional ISO Conference (Richmond), Transcript at 20.

[135] Comments of Marvin Carraway on behalf of Clarksdale Public Utilities Commission, Regional ISO Conference (Kansas City), Transcript at 107.

[136] *See, e.g.*, Comments of representative from Enron Power Marketing speaking at Commission's

Indeed, to gain a competitive advantage over those who are dependent on the timeliness and accuracy of OASIS, vertically integrated transmission owners have an incentive to make OASIS as slow and uninformative as possible.[137]

Similarly, EPSA has told us that "the present transmission regime gives existing transmission-distribution utilities an inherent advantage to reserve capacity for their own native load use, and provides them with no incentive to maintain a properly functioning OASIS." [138]

As we stated above with respect to ATC calculation, we are not in a position to make a judgment that transmission providers are deliberately making their OASIS sites difficult to use in order to disadvantage marketing competitors. In fact, we are aware that some OASIS sites are well run and engender few complaints from users, and that there may be legitimate technical and transitional difficulties responsible for some of the problems complained of. However, this is another example of the situation where market participants perceive discriminatory intent, whether or not one exists, because of the apparent opportunity and incentive to discriminate.

e. Other Issues Related to Functional Unbundling and Dealing With Remaining Undue Discrimination

While the Commission here has not attempted to provide an exhaustive compilation of the remaining opportunities for discriminatory practices by transmission operators who are also in the power business,[139] it believes that the potential for such problems increases in a competitive environment *unless* the market can be made structurally efficient and transparent with respect to information, and equitable in its treatment of competing participants. We invite public comments on the extent to which there remains undue discrimination in transmission services, and if it remains, in what forms. Those comments should address both the areas of alleged discrimination we have discussed above, as well as any other areas that commenters may have experienced. In addition, we are asking for comments about what remedies we should impose in an effort to eliminate any remaining discriminatory conduct. For example, should we require mandatory participation in an RTO, or are there other possible remedies? Could a performance-based rate system be designed to realign economic interests to remove the motive for discrimination?

One thing that seems apparent is that a system that attempts to control behavior that is motivated by economic self-interest through the use of standards of conduct will require constant and extensive policing. This kind of regulation goes beyond traditional price regulation and forces us to regulate very detailed aspects of internal company policy and communication. For functional unbundling to be successful, we have to be concerned, in some sense, about "who spoke to whom" in the company cafeteria. Functional unbundling does not necessarily promote light-handed regulation. It also undoubtedly imposes a cost on those entities that have to comply with the standards of conduct who face additional training and rules that create rigidities in their internal management activities.

It appears, based upon our experience thus far, that no matter how detailed the standards of conduct and how intensive our enforcement, competitors will continue to be suspicious that the wall between transmission operations and power sales is being breached in subtle and hard to detect ways. The perception that many entities that operate the transmission system cannot be trusted is not a good foundation on which to build a competitive power market. It creates needless uncertainty and risk for new investments in generation.

In section III.B below, we will address how the use of independent RTOs can help eliminate the opportunity for unduly discriminatory practices by transmission providers, restore the trust among competitors that all are playing by the same rules, and reduce the need for overly intrusive regulatory oversight.

B. Benefits That Regional Transmission Organizations Can Offer

In the preceding sections, we have set forth what we consider to be at least some of the remaining transmission related impediments to full competition in the electricity markets. These impediments include engineering and economic inefficiencies in the operation and structure of the existing transmission grid that inhibit the development of broad-based markets for electric power, and remaining opportunities for discriminatory practices by transmission owners with power marketing interests.

We now believe that the establishment of properly structured RTOs throughout the U.S. can effectively remove the remaining impediments to competition in the power markets. As discussed elsewhere in this NOPR, a properly structured RTO will be an entity that is independent from all generation and power marketing interests, and has the exclusive responsibility for grid operations, short-term reliability, and transmission service within a region. Such an entity would not only confer benefits related to removing impediments to competition, but would also enhance reliability and allow for less intrusive government regulation of transmission providers.

We note that the Commission's recognition of the benefits of regional transmission organizations is not new. The Commission has encouraged the industry to create such institutions for more than six years. In 1993, the Commission issued a policy statement encouraging the formation of RTGs, which were defined as voluntary organizations of transmission owners, users, and other entities interested in coordinating transmission planning (and expansion), operation and use on a regional and inter-regional basis. [140] The Commission summarized the benefits of such entities as enabling the market for electric power to operate in a more competitive, and thus more efficient manner; providing coordinated regional planning of the transmission system to assure that system capabilities are adequate to meet system demands; decreasing the delays that are inherent in the regulatory process, resulting in a more market-responsive industry; and resolving technical transmission issues (*e.g.*, loop flow).[141]

One year later, the Commission issued a transmission pricing policy statement which encouraged RTGs to address transmission pricing and offered to provide more latitude to RTGs than to individual utilities for innovative pricing proposals, recognizing that issues such as loop flow required a regional approach.[142] Then, two years after that in Order No. 888, the Commission encouraged the industry to consider ISOs, and gave specific guidance on characteristics and functions in the form of 11 principles.

July 1997 OASIS Technical Conference, transcript at 43–44.

[137] Petition at 37.

[138] EPSA Comments, Docket No. RM98–5–000. at 8 (filed September 21, 1998).

[139] There have been other violations alleged. For example, many relate to pricing and discounting.

[140] Policy Statement Regarding Regional Transmission Groups, FERC Stats. & Regs. ¶ 30,976 at 30,870 and n.4 (1993) (*RTG Policy Statement*).

[141] *RTG Policy Statement*, FERC Stats. & Regs. at 30,871.

[142] Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act, 59 FR 55031 (November 3, 1994), FERC Stats. & Regs., Regulations Preambles ¶ 31,005, at 31,140, 31,145 (*Transmission Pricing Policy Statement*.)

The Commission has not been alone in recognizing the benefits of RTOs. In fact, there is surprising unanimity about the benefits of regional transmission solutions to grid management. For example, the Edison Electric Institute adopted a resolution that "recognizes the potential benefits of voluntary grid regionalization in addressing pancaked transmission rates, congestion management and reliability, transmission planning, and market power * * *" and supported "flexible, voluntary, market-based approaches" toward grid regionalization.[143] The American Public Power Association has stated that "mandating RTOs will prevent further inequities in the provision of wholesale transmission service, provide guidance to the states, advance regional solutions to reliability issues to head off future crisis situations such as the 1998 Midwest Price Spikes, and partially mitigate serious market power concerns that have arisen due to the high number of recent mergers in the electric utility industry." [144] The National Energy Marketers Association urges the Commission to "take bold steps necessary to create larger regional transmission organizations (RTOs) and to force maximum participation into (sic) these organizations." [145] Other industry groups representing very different interests have reached similar conclusions.[146]

States are also recognizing the need for regional approaches to grid operation. At least five states have passed laws or issued regulations requiring transmission owning utilities in their states to participate in regional transmission entities.[147] Other state regulators have highly praised the new regional transmission entities that are functioning in their regions.[148]

While these industry groups and state regulators may not agree on the form of such regional organizations and how aggressive the Commission should be in encouraging their development, they do generally agree that such entities would provide substantial benefits.

We note, additionally, that this same conclusion has also been reached in other countries. In almost every country that has chosen to introduce competition in its power sector, a single regional or national grid management organization has or will be created as the necessary platform for achieving fair and efficient bulk power competition.[149]

In the following discussion, we address the significant benefits of establishing RTOs.

1. An RTO Would Improve Efficiencies in the Management of the Transmission Grid

As discussed in section III.A above, numerous inefficiencies in the current operation and structure of the transmission grid may be impeding full competition. Establishing RTOs could help remove most, if not all, of those inefficiencies in a number of ways.

First, an RTO would improve efficiency through regional transmission pricing. The Commission has long recognized that transmission pricing reform is most effectively accomplished on a regional basis.[150] An RTO would have the geographic scope needed to eliminate pancaked transmission rates within its region. This would broaden the generation market and could result in more potential suppliers and less concentrated generation markets, thereby fostering more competitive markets and lower prices to consumers.

Second, regional scope would improve congestion management on the grid. An RTO would improve the way congestion is managed over a large area, thus expanding the number of potential transactions over existing facilities while reducing the number of curtailments.

The scheduling of power by multiple utilities over a regional grid can lead to unexpected overloads on constrained facilities. This can be a serious barrier to competitive power trading because some power sale transactions may have to be curtailed. With a regional scope, an RTO would be better able to manage congestion. An RTO would be in a better position to prevent congestion or control it through application of appropriate regionwide congestion pricing to ration use of the grid if necessary. An RTO would also more readily identify schedules that could lead to congestion, and relieve congestion through regional redispatch authority. A pricing approach to capacity allocation would improve efficiency by ensuring that the most highly valued transactions remain on the grid and possibly result in less curtailment than under the present approach.

Third, an RTO would improve efficiency by providing more accurate estimates of ATC than those currently provided by individual systems. Conditions on all parts of the regional grid affect ATC on individual utility systems. Factors such as load estimates, generation and transmission outages, generation dispatch orders and transactions on individual systems can affect the determination of ATC. An individual utility may not have complete or timely information regarding such factors and may apply assumptions and criteria in its ATC estimates that are different from those of neighboring transmission operators, leading to wide variations in ATC values for the same transmission path. The information needed may be considered confidential, and market participants would be more willing to share it with an independent body.

An RTO would produce better ATC estimates because it would have access to complete regional usage information, would have current information because the RTO will be the security coordinator as well as the OASIS site administrator, and would calculate ATC values on a consistent region-wide basis using a regional flow model. An RTO would also resolve most, and perhaps all, of the complaints of inaccurate ATC

[143] Edison Electric Institute, Resolution Regarding Grid Regionalization, adopted by the Board of Directors, January 7, 1999.

[144] Motion of American Public Power Association For Leave To Lodge, Docket No. RM99-2-000, filed March 17, 1999, at 2.

[145] NEA, "National Guidelines For Restructuring The Electric Generation Transmission and Distribution Industries," January 1999, at 6.

[146] The Electric Power Supply Association recommends that "ISOs Must be Regional in Scope." (EPSA Position Statement on Independent System Operators, January 1997, at 1.) The Electricity Consumers Resource Council (ELCON) states that "a competitive electricity marketplace requires the formation of large, regional independent system operators." (ELCON, "Independent System Operators," Profiles On Electricity Issues, No. 18, March 1997, at 2.

[147] Laws to encourage participation in regional ISOs or transcos have been passed in Wisconsin, Illinois, Virginia, and Arkansas. Regulations to encourage this outcome have been issued by the Nevada commission.

[148] *See, e.g.*, Comments of Commissioner Marlene Johnson, RTO Conference (District of Columbia), transcript at 23–24; Commissioner Gerald Thorpe (Maryland), transcript at 39–40; President Herbert Tate (New Jersey), transcript at 47–50; and Commissioner Nora Mead Brownell (Pennsylvania), transcript at 54.

[149] Government of Mexico, Secretaria de Energia, *Policy proposal for structural reform of the Mexican electricity sector*, 1999; World Bank, *Reforms and Private Participation in the Power Sector of Selected Latin American and Caribbean and Industrialized Countries*, 1994; National Regulatory Research Institute, *Electric Power industry Restructuring in Australia: Lessons From Down Under*, Occasional Paper #20, Ohio State University, January 1997; World Bank (Industry and Energy Department), *Central and Eastern Europe: Power Sector Reform in Selected Countries* 1997; Ontario (Canada) Market Design Committee, *The Fourth and Final Report*, January, 1999; Alberta (Canada) Department of Energy, *Moving To Competition, A Guide to Alberta's New Electricity Structure*, 1994; Jan Moen, *A Common Electricity Market in Norway and Sweden: Prerequisites, Development and Results So Far*, Norwegian Water Resources and Energy Administration, May, 1996; National Grid Company, *Grid System Management*, Coventry, England; and J. Culy, E. Read and B. Wright, "The Evolution of New Zealand's Electricity Supply Structure," in *International Comparisons of Electricity Regulation*, Gilbert and Kahn, editors, Cambridge University Press, 1996.

[150] *Transmission Pricing Policy Statement*, FERC Stats. & Regs. at 31,145.

postings. Problems are likely to remain only to the extent that scheduling reservations across several RTOs continue to be made on a contract path basis.

Fourth, an RTO also would more effectively manage parallel path flows. With an RTO in place, the geographic scope for scheduling and pricing transmission would be widened and parallel path flows would be internalized within the RTO. This should result in more accurate ATC calculations, improve reliability, and, with appropriate transmission pricing, eliminate or reduce disputes among transmission owners regarding uncompensated uses of facilities.

Fifth, an RTO would promote more efficient planning for transmission or generation investments needed to increase transmission capacity. One advantage of an RTO that is helpful in planning is that it will be able to see the "big picture." Planning and expansion of grid facilities will no longer be done on a piecemeal basis. An RTO would help identify the best place on the grid to locate new generation.[151] An RTO also will have more options available to it because of its size and configuration. It has the potential to select and implement the most efficient investment or operating option within the region for relieving a bottleneck. This is in marked contrast to the current situation in many regions where individual transmission owners are generally limited to investment options in their particular service areas even though better (*i.e.*, less costly) options may be available elsewhere in the region.

Sixth, an RTO would increase coordination between separate state regulatory agencies by providing a single point of focus for transmission expansion review, possibly even encouraging multi-state agreements to review and approve new transmission facilities.[152] As RTOs develop viable regional planning processes, there may be a growing willingness on the part of individual states to accommodate regional regulatory review on either a formal or informal basis.[153]

Seventh, transactions costs would also be reduced with an RTO in place. For example, the consolidation of transmission control operations would cut general and administrative costs over the long term. In addition, an RTO would administer a single regional transmission tariff, thereby permitting "one stop shopping" for regional transmission service and resulting in simpler and more efficient procedures for transmission users to transmit power over greater distances.

Eighth, through regional standardization of transmission services and the terms and conditions under which they are transacted, an RTO would facilitate establishing transmission rights and the "tradeability" of transmission rights. The early experience suggests that independent regional transmission organizations are in the best position to establish well-defined rights to the use of the grid.[154] Such rights are essential to establishing congestion markets. Clear rights are also needed for the ability to trade transmission rights between customers that place different values on capacity. Such trade helps ensure an efficient allocation of current capacity and helps ensure that new capacity is built only when and where necessary.[155]

Ninth, an RTO would facilitate the success of state retail access programs by providing greater confidence in the markets and a larger regional market with access to more potential suppliers.

2. An RTO Would Improve Grid Reliability

With the improved transmission access that has resulted from industry compliance with Order No. 888, the volume of wholesale electricity transactions has significantly increased along with the number of market participants. This has led to industry concerns that traditional reliability rules may not guarantee that the bulk power system remains secure. Many transmission owners in a region make independent decisions about use of a common regional transmission grid. A reliability problem on one utility's transmission system may threaten the reliability of its neighbor's system. A regional body that operates the regional grid and enforces reliability rules for the entire region could prove helpful to current efforts and should be considered. An RTO would enhance reliability by (1) operating the system for a large region, (2) ensuring coordination during system emergencies and restorations, (3) conducting comprehensive and objective reliability studies, (4) coordinating generation and transmission outage schedules, and (5) sharing of ancillary services responsibilities.

3. An RTO Would Remove Opportunities for Discriminatory Transmission Practices

In an RTO, the control of transmission operation is cleanly separated from power market participants. An RTO would have no financial interests in any power market participant, and no power market participant would be able to control an RTO. This separation will eliminate the economic incentive and ability for the transmission provider to act in a way that favors or disfavors any market participant in the provision of transmission service.[156] Accordingly, ATC calculations can be made in an unquestionably objective manner, OASIS sites can be equally relied upon by all transmission users, and line loading relief should be free from preferences for certain market participants.

In addition, the separation of transmission operation from power marketing activities also would reduce opportunities for intentional or inadvertent communication of commercially valuable information from the transmission provider to any market participant, and should eliminate any advantage that market participants may now have with respect to arranging transmission service with an affiliated transmission provider.

Finally, removing the opportunity for discriminatory transmission practices will help ensure the openness and integrity of the commercial process. We have been told repeatedly of the importance of transparency and fairness in the relationship between transmission users and transmission providers. This was a prominent topic at our ISO conferences last year. Fairness, impartiality and market confidence are also important to reliability. If the operator orders certain actions to be taken for system reliability purposes that might harm the interests of some users, those users must know that the action being ordered has been made

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[151] One of the benefits of the ERCOT (Texas) ISO has been, due to the ISO's comprehensive view of the grid, the ability to identify the most effective spots on the grid to locate new generation facilities. *See* Chairman Patrick Wood (Texas), transcript at 205–06.

[152] The Commission recognizes that there may be legal impediments to such a shift. For example, most state siting laws typically require that the proposed facility must be assessed in terms of its benefits for the state rather than the region. *See* Ileana Elsa Garcia, "State Electric Facility Siting Practices," background paper prepared for the Harvard Electric Policy Group, April 10, 1997.

[153] To encourage this movement, we propose requiring that the RTO's planning and expansion process must "accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities." *See* section III.E.

[154] *See* Central Hudson Gas & Electric Corporation, *et al.*, 86 FERC ¶ 61, 062 at 61, 228–33 (1999); *PJM*, 81 FERC at 62,240.

[155] Capacity Reservation Open-Access Transmission Tariffs, Notice of Proposed Rulemaking, 61 FR 21847 (May 10, 1996), FERC Stats. & Regs. ¶ 32, 519 (*CRT NOPR*).

[156] Appropriate price regulation of RTOs would still be needed.

fairly and with only technical factors in mind.

One important benefit of an RTO is that it could help eliminate the suspicions about, or remaining actual discriminatory practices by, grid operators. The DOE Reliability Task Force concluded that regional reliability entities such as RTOs must be "truly independent of commercial interests so that their reliability actions are—and are seen to be—unbiased and untainted * * *" [emphasis added] [157] The same conclusion was reached by the blue-ribbon Electric Reliability Panel convened by NERC to recommend reforms in the current U.S. reliability system. The panel concluded that: "(t)o dispel suspicions that the system operator favors one participant over another * * *, the operator must be independent from market participants." [158]

4. An RTO Would Result in Improved Market Performance

By improving efficiencies in the management of the grid, improving grid reliability, and removing any remaining opportunities for discriminatory transmission practices, the widespread development of RTOs would also improve the performance of electricity markets in several ways and consequently lower prices to the Nation's electricity consumers.

The RTO benefits discussed so far in this section would result in improving the competitiveness of wholesale electricity markets. To the extent that RTOs foster fully competitive wholesale markets, the incentives to operate generating plants efficiently are bolstered. Suppliers will continuously seek to avoid being made uncompetitive by rivals. We have now had close to two decades of experience with generating plants being operated in at least partially competitive markets. Non-traditional generators have had the opportunity to realize increased profits through reduced costs and improved operating performance. For years, the growing presence of independent power generators has led to highly efficient new capacity coming on line. The evidence is clear that market incentives can lead to highly efficient plant operations.

The incentives for more efficient plant operation can also affect existing generation facilities. Especially noteworthy is the recent experience that indicates improvements in the generation sector in regions with RTOs. Regions which have ISOs in place are undergoing dramatic shifts in the ownership of generating facilities. Large-scale divestiture and high levels of new entry in California and the Northeast are changing the ownership structure of these regions' generators. Availability of customers, and the presence of competing suppliers, are creating the incentives for better-performing plants. All plants are coming under pressure to improve their availabilities and operating efficiencies. Individual firms have made strategic decisions to seek to become more competitive, or to prepare themselves for future competition. [159]

By improving competition, RTOs will also reduce the potential for market power abuse. As discussed earlier, eliminating pancaked transmission prices will expand the scope of markets and bring more players into the markets. [160] By eliminating the mistrust in the current grid management, entry by new generation into the market will become more likely as new entrants will perceive the market as more fair and attractive for investment. And with more players, the market becomes deeper and more fluid, allowing for more sophisticated forms of transacting and smoother matching of buyers and sellers.

The full value of the benefits of RTOs to improve market performance cannot be known with precision before their development, and we do not yet have a long enough track record with existing institutions with which to measure. The Commission will estimate the potential cost savings from RTOs as part of its National Environmental Protection Act analysis. At this time, we foresee several billion dollars annually in efficiency gains to the economy. [161]

The Commission seeks comment on the effect of RTOs on electricity market performance, including any data or other information that could shed light on quantifying the extent of those benefits.

5. An RTO Would Facilitate Lighter-Handed Governmental Regulation

There are several ways that the existence of a properly structured RTO would reduce the need for Commission oversight and scrutiny, which would benefit both the Commission and the industry.

A number of regulatory benefits depend critically on the RTO being truly independent of power marketing interests. For example, to the extent an RTO is independent of power marketing interests, there would be no need for this Commission to monitor and attempt to enforce compliance with the standards of conduct designed to unbundle a utility's transmission and generation functions.

An independent RTO with an impartial dispute resolution mechanism would resolve disputes without resort to the Commission complaint process. The Commission has demonstrated its willingness to defer to such mechanisms. [162] It is generally more efficient for these organizations to resolve many disputes internally rather than bringing every dispute to the Commission. We seek comment on what types of disputes or other matters would be appropriate for the Commission to defer to the decisions of the RTO? In granting deference to decisions that result from an acceptable ADR process,

[157] *See* Secretary of Energy Advisory Board, U.S. Department of Energy, "Maintaining Reliability in a Competitive U.S. Electricity Industry," September 29, 1998 at xv.

[158] Electric Reliability Panel of the North American Reliability Council, "Reliable Power: Renewing the North American Electric Reliability Oversight System," December 1997, at 17.

[159] Examples include: Virginia Power, which has made more than $1 billion in capital improvements and other investments (without raising rates) between 1992 and 1998, including $921 million in generating plant and approximately $125 million in transmission line upgrades. *See* Virginia Power, Virginia Power Statement on SCC Report, May 24, 1998. This document is available on Virginia Power's website at http://www.vapower.com/news/archive/releases980324.html; Entergy, which has achieved high performance at its nuclear units in terms of capacity factors, outage times and refueling periods, *See* Entergy Operation Services, Inc., Entergy Nuclear Units Have Outstanding Year as Entergy Forges Ahead with National Nuclear Company, January 26, 1999, press release. This document is available on Entergy's website at http://www.entergy.com/news/1999/nr012699.htm.; New York Power Authority, which has lowered operating and maintenance budgets, refinanced debt, and invested $181 million in capital improvements. *See* New York Power Authority, NYPA Exceeds Performance Goals in 1998, February 12, 1999, press release. This document is available on NYPA's website at http://www.nypa.gov/press/0212a.htm.; Green Mountain Power, which reduced operations and maintenance expenditures by 50% between 1998 and 1995. *See* Green Mountain Power Corporation, Sales and Expenditures, 1995 Annual Report. This document is available on Green Mountain Power Corporation's website at http://www.gmpvt.com/annrpt95/salesex2.htm; and the Tennessee Valley Athority, which realized cost savings of 22% on fossil-fueled and hydroelectric plant outage projects which were subject to a continuous improvement process. *See* Hans E. Picard and C. Robert Seay, Jr., Competitive Advantage Through Continous Outage Improvement, Electric Power Research Institute Fossil Plant Maintenance Conference, July 29, 1996. This document is avialable at website http://www.iac.net/ pconsult/epri.html..

[160] Evidence from the UK and strategic behavior studies, however, indicates that such market power can lead to ongoing cost impacts as well as outright efficiency losses. *See* Richard Green and David Newbery, Competition in the British Electricity Spot Market, 100 J. POL. ECON., 929, 1992.

[161] The benefits are likely to come substantially from lower generation operation and maintenance costs that result from new plants, improved performance of existing plants, and improved congestion management.

[162] *See PJM*, 81 FERC at 62,269.

would there be a need to distinguish between RTOs that are ISOs and RTOs that are transcos?

The Commission could also consider adopting streamlined filing and approval procedures. The Commission could consider different filing requirements for established RTOS. For example, should we lower the threshold for the types of changes to operations or practices that would not require a filing with the Commission? Should such a policy be applied equally for non-profit and for-profit RTOs?

Another regulatory benefit is that an RTO could result in more streamlined transmission rate proceedings. The Commission has indicated its willingness to grant more latitude to transmission pricing proposals from appropriately constituted regional groups, and RTOs would be such groups.[163]

To the extent that RTOs increase market size and decrease market concentration, the competitive consequences of proposed mergers would become less problematic and thereby help further streamline the Commission's utility merger decision making process.

6. Conclusion

The Commission believes that the widespread formation of RTOs can provide substantial benefits. The Commission invites comment on the benefits of RTOs and the magnitude of these benefits.

C. Concerns Expressed by the State Commissions

Our Notice of Intent to Consult with State Commissions in this proceeding initiated our commitment to take into account the advice and concerns of the states in formulating an RTO policy. Through written and oral comments made during the consultations in February 1999, and in response to a series of follow-up questions, state commissioners raised a number of concerns regarding RTO policy. The Commission appreciates the state commissioners' serious consideration and their comments have helped shape our proposal. We take the opportunity to summarize the principal concerns and how our proposal addresses those concerns.

1. Federal Mandate

Most states oppose a FERC mandate to form RTOs.[164] The proposed rule would not generically require public utilities to transfer control of their transmission facilities to an RTO; however, we do seek comment on the issue. We are proposing to provide the impetus needed to help form RTOs by engaging the industry and the states in a national dialogue regarding RTO characteristics, setting minimum characteristics and functions for RTOs, providing flexibility for innovative transmission rate proposals, including a willingness to consider incentive pricing proposals, and establishing regional processes with Commission staff participation after a Final Rule is issued for fostering RTO formation. Thus, the proposed rule stops short of generically ordering utilities into RTOs but instead, as WUTC expresses it, we are at this time adopting: "* * * a policy of encouraging voluntary RTO participation and filings * * *"[165] The Commission is, however, concerned that the current transmission grid management framework may be preventing electricity markets from reaching their full competitive potential. We will evaluate the comments received in response to our proposals to determine if additional action is needed.

2. Regional Flexibility

At all three consultations with the state commissions and in written comments, we were urged by almost every state commission not to impose a "one size fits all" approach to RTO design.[166] The vast majority of the respondents to the Commission's follow-up questions were unwilling to designate a particular type of RTO organization as superior in all cases. The Commission agrees and does not propose to establish a mandatory national template for RTOs. Such a policy would be ill advised at this time. Neither this Commission, nor, we suspect, anyone else in the industry knows now what is the best combination of ownership and control to achieve an optimal RTO. Given the lack of experience to date, the Commission believes that the best policy is to encourage regional experimentation. Thus, as discussed below, the proposed rule would establish only minimum characteristics and functions needed for Commission approval as an appropriate RTO. We also propose to initiate collaborative regional processes in which each region would be encouraged to design an RTO that best meets its needs. This collaborative process is discussed below.

Our proposed policy of regional flexibility should also help some states' concerns with the cost of an RTO. As discussed above, we believe RTO development will result in substantial benefits for the Nation. However, some states are concerned that the costs of an RTO will exceed its benefits. The cost of meeting the minimum RTO characteristics need not be large, but it is not always easy to measure the long-term RTO benefits that would offset these costs. By permitting regional flexibility, subject to our minimum characteristics and functions, the proposed rule allows each region to design an RTO that has costs commensurate with the regional benefits expected.

3. Retail Markets

States that have not adopted a retail access policy are concerned that an RTO in their state might interfere with their prerogatives regarding adopting, or not adopting, retail access. The comments and responses of some state commissions reiterate the concern that RTO formation will lead to retail access where it does not yet exist.[167] The proposed rule does not require retail access. The Commission agrees with FPSC that, "FERC should not pursue any policy that would interfere with or contravene a state's authority to adopt or refrain from adopting direct retail access."[168] Having an RTO in a state does nothing to interfere with the state's authority to decide retail access policy. Some states whose utilities are in RTOs can have retail access while others can choose not to have retail access. This is demonstrated today by the presence of ISOs in the Middle Atlantic and New England regions, but not all of the states in those regions have yet adopted retail competition. Some states with retail access believe that an RTO is needed to support their customer choice plan because the RTO allows customers, aggregators and marketers to reach supplies over a larger area. Those states that do not have retail access can nevertheless benefit from an RTO as their utilities enjoy the benefits of the RTO to lower native load generation rates by buying and selling power over a larger market area.

Some states are also concerned that having a Commission-regulated RTO provide transmission service for retail

[163] *See Transmission Pricing Policy Statement,* FERC Stats. & Regs. at 31,145, 31,148.

[164] *See, e.g,* Comments in Docket No. RM99-2-000 of North Carolina Utilities Commission (NCUC) at 1; Washington Utilities and Transportation Commission at (WUTC) at 4; Georgia Public Service Commission (GPSC) at 10; Mississippi Public Service Commission (MPSC) at 3; and South Carolina Public Service Commission (SCPSC) at 1.

[165] WUTC at 4-5.

[166] *See, e.g.,* comments of Florida Public Service Commission (FPSC) at 3.

[167] *See, e.g.* response of Kentucky Public Service Commission (KPSC) at 1.

[168] FPSC comments at 4.

customers would lead to some loss of control over retail market services, such as the ability to assure reliability. A primary purpose of an RTO is to ensure transmission reliability. Whether there is any decrease in state control over any aspects of retail market services would depend on the design of the particular RTO. Under any RTO design, the states would retain full control over the generation adequacy of franchised power suppliers, transmission siting and local distribution reliability. Further, the proposed rule would encourage state involvement both in RTO design and ongoing oversight, providing states a vehicle to protect all aspects of transmission reliability on behalf of retail customers.

4. Effect on States with Low Cost Generation

States with relatively low cost power are concerned that an RTO would result in local utilities selling their low cost power to other states. However, the vast majority of the respondents to a follow-up question on this issue stated that this is not a likely problem.[169] Similarly, we do not believe RTOs will cause such a result. The presence or absence of retail access is the principal factor affecting potential out-of-state sales of low-cost power, and this is in the hands of state policy makers. Arguably, retail access could lead to low cost power being sold out of state if incumbent utilities no longer have an obligation to serve retail customers. However, this could happen with or without an RTO. Where there is no retail access, state authorities can continue to ensure that a utility with a monopoly franchise sells its lowest cost power to local native load, even if the utility's transmission is operated by an RTO. Indeed, an RTO could actually lower retail rates by expanding the market region for the utility to sell the higher cost power not sold to native load and sharing in the benefits of regionwide resource planning and congestion management.[170] And finally, utilities that now have low cost generation will help assure access to future low cost generation plants by participating in an RTO. New low-cost generation plants are more likely to be attracted to regions with a well-functioning regional market governed by an RTO.[171] In other words, a state that is low-cost today may not be low-cost tomorrow without an RTO in its area.

We seek comment from state commissions regarding how an RTO in their state would affect power costs.

5. Need for Independent Transmission Operation

Many states believe that transmission operators should be structurally independent of other market participants. Responses to follow-up questions indicated that independence of the transmission operator is a basic assumption for an effective RTO.[172] As the Pennsylvania Public Utility Commission (PaPUC) states, "It is therefore the case that RTOs must have sufficient independence from direct control by any single entity or interest group to perform these functions well and honestly." [173] As discussed below, our proposed rule would require strict independence of transmission operation from market participants for approval of an RTO application.

6. Transmission Cost Shifting

There is a concern by some states with utilities with relatively low cost transmission facilities that, by joining an RTO, their utilities' transmission costs will be averaged with the higher cost facilities of utilities in other states in determining RTO transmission rates.[174] As a result, these states are concerned that joining an RTO will increase local transmission rates. This is known as transmission cost shifting. It has been an issue in every ISO the Commission has approved to date. That is why, in each of those ISO cases, we have allowed a transition period in which access fees are based on some form of "license plate" pricing: access fees are paid by load serving entities based on the fixed transmission costs of the local utility. As discussed below, we propose to continue and perhaps expand such flexibility in allowing the license plate approach or other approaches to recover current sunk transmission costs during a transition period.

7. Boundary Drawing

Many states expressed opposition to the Commission drawing regional or RTO boundaries in a rulemaking.[175] The proposed rule does not set boundaries. Instead, we propose factors for assessing whether a proposed RTO's geographic configuration will ensure that the required RTO functions, such as assuring reliability, internalizing loop flow, managing congestion, and eliminating pancaked rates, are satisfied. In other words, we are proposing that the boundaries and other factors affecting scope and regional configuration will depend on the functions that an RTO performs. We note, however, that some RTO functions are likely to be carried out more effectively in a large region.

8. Regional Approach to Reliability

Many states believe that regional operation of transmission is needed to assure the continued reliability of the transmission system.[176] The proposed rule would require regional operation of transmission by an RTO with primary responsibility for short-term reliability as a condition for approval of an RTO application. This is discussed below.

9. Pricing Reform

Many states want regional approaches to transmission pricing reform. In particular, they would like to decrease the incidence of pancaked transmission rates. Our proposal is aimed at developing RTOs that would provide the forum and have the geographic scope for a regional approach to transmission pricing reform. The proposed rule would also permit flexibility for experimenting with innovative forms of congestion management, which would mean fewer TLR curtailments and more assurance that native load is served.

10. Participation of Public Power

In some regions of the Nation, substantial portions of the transmission grid are owned by pubic agencies. The states in these regions have expressed a concern that our RTO initiative must address how to assure that such public agencies join the RTO. Some of the responses to follow-up questions reiterated the need to include public power agencies in any RTO formation.[177]

The proposed rule would not require RTO formation and so does not address

[169] *See, e.g.*, responses of Virginia State Corporation Commission (VSCC) at 1; WUTC comments at 2; Wisconsin Public Service Commission (WPSC) comments at 1; and Florida Public Service Commission (FPSC) comments at 1. *But see, e.g.*, response of Alabama Public Service Commission (APSC) at 1, and response of District of Columbia Public Service Commission (DCPSC) at 1.

[170] *See* response of Indian Utility Regulatory Commission (IURC) at 1.

[171] According to data in a recent survey, about 64% of announced merchant power plants will be located in California, Texas, New York, New England, and the middle Atlantic area, while such states account for only about 30% of total electricity load in the U.S. *See* Announced Merchant Plants, survey prepared by the Electric Power Supply Association, April 13, 1999.

[172] *See e.g.*, responses of KPSC at 2 and Missouri Public Service Commission (MoPSC) at 1.

[173] Supplemental comments at 7.

[174] *See, e.g.*, comments of WUTC at 6.

[175] *See, e.g.*, comments of NCUC at 1 and WUTC at 3.

[176] *See, e.g.*, comments of NCUC at 3.

[177] *See, e.g.*, responses of Iowa Utilities Board (IUB) at 1 and New Mexico Public Regulation Commission (NMPRC) at 1.

how to require public agency transmission owners to join RTOs. As suggested by KPSC,[178] we will allow flexibility in RTO formation in order to meet, where possible, the requirements of public agencies. Nevertheless, the Commission's objective is to encourage the placement of all transmission facilities under the control of an RTO. In section III–G of this notice, we have requested comments on ways the Commission can facilitate public power participation in RTOs. We are also proposing regional processes to help facilitate RTO formation under section 202(a) of the Federal Power Act. Because section 202(a) applies to public power as well as public utilities, the regional processes will include publicly owned transmission entities.

11. State Role in RTO Governance

States want a role in the governance of any RTOs for their states, and the Commission proposes to be as flexible as possible in accommodating their needs. The state commission responses to follow-up questions show that some states want to be closely involved in RTO operation[179] while others believe it better to remain independent of the RTO in order to engage in better oversight.[180] Practically all respondents see siting authority remaining with the states.

As discussed below, the proposed rule encourages RTO design to accommodate appropriate state oversight, especially with regard to planning and siting new multi-state transmission facilities. We request comments on the appropriate state role in RTO governance. For example, should state government officials participate as voting members of an RTO?

12. Existing Regional Transmission Entities

During our consultations, many of the state commissioners from the northeastern region and a representative from California, where transmission facilities are already, or soon will be, under the control of Commission-approved ISOs, asked that the Commission not require major changes to these ISOs during their implementation periods.[181] The commissioners observed that their states' ISOs were still undergoing an implementation and learning period and, in some instances, are important to retail choice program implementation.

The Commission respects the investment of time and other resources made in the existing ISOs. We understand the importance of avoiding change during the critical implementation periods. Due to these considerations, and our proposed policy of regional flexibility, the proposed rule does not require major changes to the existing transmission entities that the Commission has found in conformance with the ISO principles of Order No. 888 at this time, absent compelling circumstances. However, any entity must meet our minimum RTO characteristics and functions to receive any of the benefits to be accorded RTOs. Our objective is to have all of the Nation's transmission grid under the control of RTOs that have the minimum characteristics and functions adopted in the Final Rule. That is why we propose to require the public utility members of existing transmission entities that have been found in conformance with the Commission's ISO principles to make a filing, individually or jointly, with the Commission no later than October 15, 2000, that explains the extent to which the entity in which it or they participate meets the minimum RTO characteristics and functions. The Commission is also concerned about impediments to transactions between existing ISOs (as well as any future RTOs). We therefore encourage existing ISOs to consider ways to reduce any impediments to transactions among them.

The Commission invites further comments from the state commissions on all aspects of the proposed rule.

D. Minimum Characteristics and Functions for a Regional Transmission Organization

In this section, we propose minimum characteristics and functions for a transmission entity to qualify as an RTO. These characteristics and functions are designed to ensure that any RTO will be independent and able to provide reliable, non-discriminatory and efficiently priced transmission service to support competitive regional bulk power markets. There are four minimum characteristics for an RTO:

(1) Independence from market participants;

(2) Appropriate scope and regional configuration;

(3) Possession of operational authority for all transmission facilities under the RTO's control; and

(4) Exclusive authority to maintain short-term reliability.

In addition, there are seven minimum functions that an RTO must perform. An RTO must:

(1) Administer its own tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities;

(2) Create market mechanisms to manage transmission congestion;

(3) Develop and implement procedures to address parallel path flow issues;

(4) Serve as a supplier of last resort for all ancillary services required in Order No. 888 and subsequent orders;

(5) Operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC;

(6) Monitor markets to identify design flaws and market power; and

(7) Plan and coordinate necessary transmission additions and upgrades.

The Commission seeks comment on the following questions: (1) whether the Commission's enumeration of minimum criteria omits a necessary minimum characteristic or function, or includes an unnecessary characteristic or function; (2) whether there is a need to distinguish between minimum characteristics and minimum functions (*i.e.*, adopt separate categories for the minimum requirements); and (3) if so, whether any of the minimum characteristics should be re-characterized as minimum functions, and vice versa. Comments on these questions should take into account the Commission's objective in this rulemaking of encouraging the formation of RTOs that promote competitive markets and non-discriminatory access to, and reliable operation of, the electric grid.

Under this proposal, all RTOs must satisfy the four minimum characteristics on their first day of operation as approved RTOs. The Commission also proposes that all RTOs be prepared to perform at least four of the seven minimum functions on their first day of operation as approved RTOs. Recognizing that more time may be needed to perform certain functions, we are proposing that for the other three of the functions—establishing procedures for addressing parallel path flows with neighboring systems, managing congestion, and planning transmission expansion—additional time ranging from one to three years after initial operation will be allowed.

The Commission seeks comments on whether we should grant RTO status to entities that are not able to perform immediately these three functions. The Commission also seeks comments on

[178] Response at 1.

[179] *See, e.g.*, responses of WUTC at 4 and Arizona Corporation Commission (ACC) at 2.

[180] *See, e.g.*, response of Wisconsin Public Service Commission (WPSC) at 3.

[181] *See, e.g.*, Comments at the Washington, DC conference of New England Conference of Public Utilities Commissioners, Inc. (NECPUC) at 4 and remarks of California Senator Peace, RTO Conference (Las Vegas), transcript at 3–4.

whether we should grant RTO status to entities that may not be able to perform on the first day of operation certain other (i.e., any of the remaining four) of the minimum functions. Should we differentiate, for purposes of initial implementation, between any of the seven minimum functions? If so, has the Commission appropriately identified those minimum functions that are most likely to require additional time to perform?

We propose to give transmission entities flexibility in deciding how to meet these seven minimum functions. For five of the functions (tariff administration, congestion management, ancillary services, market monitoring and planning and expansion), we propose to establish standards for how the function is performed, but an RTO will have the option of demonstrating that an alternative proposal is consistent with or superior to the standards in the proposed rule.[182] The Commission seeks comment on whether this flexibility—i.e., the option of demonstrating that an alternative proposal is consistent with or superior to the proposed rulemaking standards—should apply to any or all of the minimum characteristics.[183]

We also propose that the RTOs would have flexibility in designing their organizational structures. We are receptive to all types of RTO proposals as long as they satisfy the specified minimum characteristics and functions. For example, we will consider proposals for non-profit or for-profit organizations. An RTO can be an operator of the grid that it controls, an operator and owner of the grid that it controls, or a combination of the two.[184] The minimum characteristics and functions provide a wide range of implementation flexibility and discretion. They represent a floor, not a ceiling. To encourage further evolution, the Commission is proposing an "open architecture" requirement. Under this requirement, the RTO must permit further improvements that will enhance the efficient operation of regional bulk power markets.

[182] We use the term "standard" to refer to the required sub-elements under each characteristic and function.

[183] Alternative proposals may include requests for appropriate transition periods. We will consider such proposals on a case-by-case basis, based on an assessment of their effect on regional power markets.

[184] One example of an arrangement that combines these two approaches would be a transmission entity that owns and operates some transmission facilities and operates other facilities under long-term leases or other agreements with existing or new transmission owners.

Minimum Characteristics

1. Characteristic 1: Independence. The RTO Must be Independent of Market Participants. (Proposed § 35.34(i)(1))

Market participants must be assured that the RTO will provide transmission access to all market participants on a fair and non-discriminatory basis. The Commission believes that it is a prerequisite for achieving fair, open and competitive power markets. An RTO needs to be independent in both reality and perception.[185] As we have said before in the context of ISOs, we think that "the principle of independence is the bedrock upon which the ISO must be built * * *"[186] It is the Commission's view that independence can be achieved if the RTO satisfies three conditions. First, the RTO, its non-stakeholder governing board members and its employees must have no financial interests in market participants.[187] Second, the RTO's decision making must not be controlled by any market participants. Third, the RTO must have independent authority to file changes to its transmission tariff. We now discuss these conditions.

a. The RTO, its employees and any non-stakeholder directors must not have financial interests in any electricity market participants. (Proposed § 35.34(i)(1)(i))

We propose that the RTO, the non-stakeholder members of its governing board and all employees be prohibited from having financial interests in any market participants. The prohibition clearly applies to current financial interests. It does not preclude past financial ties with market participants. Nor does it require a total or permanent prohibition on all future financial ties with market participants in the region. Such a prohibition would make it difficult for the RTO to hire experienced and knowledgeable employees. Therefore, we will employ a rule of reason standard in deciding what financial ties with market participants would be acceptable after an individual leaves the RTO. As has been the case in our review of conflict of interest standards for ISOs, the Commission would establish these standards on a case-by-case basis.[188]

The Commission requests commenters to address some or all of the following issues related to the proposed requirements. Do we need to define the financial independence requirement in more specific terms or is it sufficient to enunciate the general principle and then apply it on a case-by-case basis? Should the definition of stakeholders or market participants be expanded to include entities that operate distribution-only facilities (*i.e.*, entities that perform the "wires" function at lower voltages) and transmission entities in neighboring regions? Should this definition be broadened to include sellers and buyers of ancillary services? Are there any circumstances in which the definition should be expanded to include entities that do not participate in power markets in the region but that provide transmission services to the RTO or buy transmission service from the RTO? Do we need to add more specificity to the requirement that RTOs have conflict of interest standards? Are there lessons to be learned from the experience of ISOs with conflict of interest standards that can now be applied more generally to RTOs?

b. An RTO must have a decisionmaking process that is independent of control by any market participant or class of participants. (Proposed § 35.34(i)(1)(ii))

This requirement would be satisfied, for example, by an RTO with (a) a non-stakeholder governing board and (b) a prohibition on market participants having more than a *de minimis* (one percent) ownership interest in the RTO.[189] The Commission seeks

[185] This is also the conclusion of almost every one of the state commission representatives who attended our recent consultatons with the state regulatory community. *See, e.g.*, Comments of Commissioners Marlene Johnson and Herbert Tate, Regional ISO Conference (Washington, D.C.), transcript at 66–67, 95; Comments of Judy Sheldrew, RTO Conference (Las Vegas), transcript at 58.

[186] Atlantic City Electric Company, *et al.*, 77 FERC ¶ 61,148 at 61,574 (1996). The same conclusion was reached by the DOE Reliability Task Force and the NERC Reliability Panel. The DOE Task Force concluded that regional reliability entities must be "truly independent of commercial interests so that their reliability actions are—and are seen to be—unbiased and untainted * * *" Task Force Report at xv. The Electric Reliability Panel concluded that "(t)o dispel suspicions that the system operator favors one particular over another * * * the operator must be independent from market participants." North American Electric Reliability Council, Electric Reliability Panel, Reliability Power: Renewing the North American Electric Reliability Oversight System, December 22, 1997, at 17.

[187] We use the terms "stakeholder" and "market participant" interchangeably. They mean any entity that buys or sells electric energy in the RTO's region or in any neghboring region that might be affected by the RTO's actions, or any affiliate of such entity.

[188] *See, e.g. Midwest ISO*, 84 FERC at 62,152–53, *order on reh'g* 85 FERC at 62,036; *NEPOOL*, 79 FERC at 62,586–87.

[189] It is our understanding that a similar standard was established by the British government when it created the National Grid Company (NGC), the largest, for profit transmission company in the world. The company's basic corporate documents

comments on whether this kind of RTO should be deemed to satisfy automatically this element of the independence requirement. We also request comments on whether there should be a single standard for independent decision making for all RTOs regardless of whether they are for-profit or non-profit entities. The Commission recognizes that there may be other ways to satisfy the independent decision making requirement. Therefore, we propose to consider other governance and ownership proposals, which will be judged on a case-by-case basis against the general requirement of independent decisionmaking.

With regard to the RTO governing board, we propose to define a non-stakeholder governing board as a governing board of individuals without any financial ties to market participants or their affiliates. Individuals on such a board are independent, rather than representative, of market participants. Board members usually have experience in a variety of fields related to the RTO's operations. These could include, among others, transmission operations and planning, law, electricity regulation, business management, market analysis, and risk management. The non-stakeholder board would be the ultimate decision making authority, though it could choose to delegate decisions to its staff or committees of stakeholders.[190] The board would be advised by the RTO staff and perhaps by a committee of stakeholders. In recent proceedings, we have accepted this two tier approach because it represents a middle ground in that it attempts to balance independence with expertise.

In the case of a non-stakeholder board, how can we ensure that the concerns of market participants are communicated effectively to the board? We request comments on what, if any, additional requirements should apply to a governing board that is not a stakeholder board or to a governing board with both stakeholders and non-stakeholders. For either stakeholder or non-stakeholder boards, should we impose an upper limit on the size of the board? How should the Commission consider proposals for state regulatory or other governmental officials to select board members for either stakeholders or non-stakeholder boards? How should the Commission view proposals for state government officials to serve as voting members of RTO boards?

With regard to market participants having no more than a *de minimis* interest in the ownership of the RTO, we propose to consider a *de minimis* interest as having no more than a one percent interest in the ownership of an RTO. We seek comment on whether one percent is an appropriate *de minimis* ownership interest and, if not, what would constitute appropriate *de minimis* ownership for purposes of establishing independence. We also request comment on whether there are conditions under which market participants should be allowed to have more than a *de minimis* ownership interest in an RTO. Should the Commission have a different standard for passive interests? How should the Commission treat preferred equity shares?

There are several reasons why we are proposing that the independent decision making standard can be satisfied by an RTO with (a) a non-stakeholder governing board and (b) a prohibition on market participants having more than a *de minimis* (one percent) ownership interest in the RTO. First, affiliated transmission companies (*i.e.*, transmission companies in which one or more market participants have more than a *de minimis* ownership interest) may not be trusted by market participants even with elaborate protections (*e.g.*, voting trusts, independent trustees and corporate boards not chosen by the owners). We believe that market participants are likely to suspect that the safeguards will be gamed. This, in turn, could affect investment behavior. In particular, market participants may be reluctant to make needed investments in generation or marketing of electricity if they believe that the RTO is likely to give favored treatment to its affiliates.

Second, affiliated transmission entities that are not independent of market participants would continue the regulatory need for detailed and hard to enforce codes of conduct. If we permit RTOs to be affiliated with one or more market participants, we believe that the Commission may have to devote considerable regulatory resources to "chasing after conduct" (*i.e.*, allegations of favoritism). If our experience with functional unbundling as well as with affiliated natural gas pipelines provides any lessons, we will probably find it necessary to issue detailed rules that deal with internal corporate matters relating to organizational responsibilities, corporate communications, etc.[191] For this reason, the existence of affiliated transmission entities also could make it difficult to pursue light-handed regulation.

Commenters are asked to address whether these are reasonable assessments of the effects of allowing market participants to have more than a *de minimis* ownership interest in RTOs. Is there relevant experience from other regulated industries? If we were to allow market participants to have more than a *de minimis* ownership interest for a transition period, how long should the transition period be? Would any additional safeguards be required during such a transition period? In general, which type of institution would better serve the goal of independence: a transco with *de minimis* ownership and a non-stakeholder board or an ISO with a non-stakeholder board?

c. 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. (Proposed § 35.34(i)(1)(iii)

We believe that independence requires that the RTO provide service under its own open access transmission tariff and that it has the right to file changes to its tariff with the Commission on its own authority. In other words, the RTO should not be required to get the prior approval of transmission customers, transmission owners or any other entities to make Section 205 filings with the Commission. The rationale is that if the RTO is taking over the open access transmission service obligation from current transmission providers, the RTO

prohibit market participants from serving on NGC's board and from owning more than one percent of the shares in its voting equity. A similar prohibition appears to exist in the Wisconsin state law that mandates Wisconsin utilities to join either an ISO or an independent transmission company by a specific date. *See* 1997 Wisconsin Act 204, Section 30.

[190] An ISO governing board's delegation of decisions to a stakeholder committee would be contingent on this committee not being dominated by one segment of the industry. We recently found that the existing tiered governance arrangements of the New York and New England ISOs failed to meet this standard and we ordered both ISOs to reduce the voting power of dominant utilities in the lower tier of stakeholders charged with advising the non-stakeholder governing boards. *See Central Hudson*, 87 FERC at __, slip. op. at 12–13; New England Power Pool, 86 FERC ¶ 61,262 at 61,965.

[191] Natural gas pipelines that transport gas for others and are affiliated with gas marketers or brokers must conform to the standards of conduct outlined in Section 161.3 of the Commission's regulations. Further, such pipelines, pursuant to Section 250.16 of the Commission's regulations must maintain: (a) provisions in their effective tariffs that divulge operating employees and facilities shared by the pipeline and its affiliate(s) and the procedures used to address complaints; (b) a data log showing, by customer (affiliate and non-affiliate), how capacity on the pipeline was allocated; and (c) information concerning shippers receiving discounted rates. Within the natural gas pipeline industry, these requirements are sometimes viewed as overly intrusive regulation. *See* "FERC Clarifies Affiliate Etiquette For Gas Pipelines," The Energy Daily, November 17, 1998, at 1.

must be able to independently and unilaterally propose changes in its tariff.[192] While this is not likely to be a concern for transcos, our recent experience suggests that it is an important issue for ISOs that seek to become RTOs. We have approved ISOs that appear not to meet this standard. For example, the New England ISO provides transmission service under the tariff of the NEPOOL RTG rather than its own tariff.[193] In our order approving the Midwest ISO, we stated that: "We believe that any problems that may arise can be addressed by the Midwest ISO's authority to file changes unilaterally to the congestion management procedures." [194] However, our order also accepted a requirement that the ISO get the prior approval of existing transmission owners before filing certain types of changes in its tariff with us.[195] Separately, we have a pending request for clarification on this issue from the PJM ISO.[196] Can an RTO be truly independent if it does not have the authority to file changes in its tariff without the approval of other entities such as transmission owners? Should the ISO's unilateral filing authority be limited to transmission rate design and terms and conditions that directly affect access but not to changes that would affect transmission owners' ability to collect their overall revenue requirements? In practice, is this a viable distinction? If an RTO's filed rate schedule also includes market design rules, should the RTO have Section 205 filing authority to make changes in these rules?

2. Characteristic 2: Scope and Regional Configuration. The RTO must serve an appropriate region. The region must be of sufficient scope and configuration to permit the RTO to effectively perform its required functions and to support efficient and nondiscriminatory power markets. (Proposed § 35.34(i)(2))

We propose that all RTO proposals filed with us identify a region of appropriate scope and configuration. The scope and configuration of the regions in which RTOs are to operate, and the extent to which RTOs control the transmission facilities within a region, will significantly affect how well they will be able to achieve the desired regulatory, reliability, operational, and competitive benefits. Accordingly, we set forth below what we consider to be relevant factors that may affect the appropriate scope and configuration for a region that an RTO will serve.[197] If the formation of RTOs is undertaken without considering the goals that large regions can best achieve, it is unlikely that RTOs will be configured to provide maximum benefits. Transmission owners could seek to gain strategic advantage by the way an RTO is formed. For example, an RTO could be placed to act as a toll collector on a critical corridor.[198] Alternatively, an RTO could propose configurations that interfere with the formation of a larger, more appropriately configured RTO.

The Commission is aware that there is likely no one "right" configuration of regions. One particular boundary may satisfy one desirable RTO objective and conflict with another. The industry will continue to evolve, and the appropriate regional configurations will likely change over time with technological and market developments. The Commission is also mindful of the interests of individual states regarding RTO boundaries. Given all these considerations, the Commission believes that the public interest will best be served if we establish at the time of the Final Rule a set of factors that encourage appropriate regional configuration, without actually prescribing boundaries.

In the discussion that follows, the Commission sets forth, and solicits comments on, the factors that it believes are important for an appropriately configured region in which an RTO would operate.

a. Factors Affecting The Appropriate Scope And Regional Configuration Of An Acceptable Region

The Commission has grouped the factors that it believes are significant to developing appropriate regions into regional configuration factors and factors for evaluating boundaries.

i. Regional Configuration Factors

The Commission believes that the most important consideration in evaluating the geographic configuration of an RTO is that such configuration permit the RTO to perform its functions effectively. We believe that many of the characteristics and functions for an RTO proposed in this section suggest that the regional configuration of a proposed RTO should be large in scope.[199] For example:

- Making accurate and reliable ATC determinations: An RTO of sufficient regional scope can make more accurate determinations of ATC across a larger portion of the grid using consistent assumptions and criteria.
- Resolving loop flow issues: An RTO of sufficient regional scope would internalize loop flow and address loop flow problems over a larger region.
- Managing transmission congestion: A single transmission operator over a large area can more effectively prevent and manage transmission congestion.
- Offering transmission service at non-pancaked rates: Competitive benefits result from eliminating pancaked transmission rates within the broadest possible energy trading area.
- Operations: A single OASIS operator over an area of sufficient regional scope will better allocate scarcity as regional transmission demand is assessed; promote simplicity and "one-stop shopping" by reserving and scheduling transmission use over a larger area; and lower costs by reducing the number of OASIS sites.
- Planning and coordinating transmission expansion: Necessary transmission expansion would be more efficient when planned and coordinated over a larger region.

The Commission recognizes, however, that there may be other factors that limit how large a region may be, for example, the requirement that an RTO be the grid operator. There may be a limitation on how many facilities or transactions can be reliably overseen by a single operator, imposed either by hardware

[192] The Commission has previously stated that the "[a]uthority to act unilaterally . . . is a crucial element of a truly independent ISO." 79 FERC ¶ 61,374 at 62,585 (1997).

[193] This has been protested by the New England Conference of Public Utility Commissioners. *See* "Motion For Leave To Submit Answer. . . .," Docket Nos. OA97-237 and ER97-1079, April 8, 1997.

[194] *See Midwest ISO*, 84 FERC at 62,163.

[195] *Id.* at 62,151.

[196] "PJM Interconnection, LLC's Request For Clarification, Or In The Alternative, Rehearing," Docket No. OA97-261, December 27, 1997.

[197] We note that a number of parties have asked the Commission to take the initiative to make the RTO formation process more orderly. For example, 11 state commissions filed a petition with FERC in February 1998 (which was noticed in both the Midwest ISO proceeding and in the generic ISO inquiry) asking FERC to take action on the geographic configuration of ISOs, arguing that inappropriate borders for ISOs could result in reduced customer benefits, economic inefficiencies, unnecessary complication of coordinated operations, and detrimental impacts on planning. However, in our three RTO conferences, representatives of several other state commissions expressed concern about the Commission playing too strong a role in RTO formation, arguing, for example, that we should not define RTO geographic boundaries but should leave this to the parties in each area of the country to determine.

[198] *See* Statement of Ohio Commission Chairman Craig Glazer, RTO Conference (St. Louis), transcript at 85–87.

[199] This reiterates the conclusion we reached in the eleven ISO principles in Order No. 888, where we stated that "[t]he portion of the transmission grid operated by a single ISO should be as large as possible." *Order No. 888*, FERC Stats. & Regs. at 31,731.

design or costs, or imposed by human limitations to process the required amount of information.

The Commission is not proposing that the RTO must be a control area operator, although four of the five ISOs approved so far by the Commission are each a single control area.[200] If those forming an RTO decide that the RTO should be a control area operator, this too may limit the RTO's size. However, control area functions might be performed over a large area by a master-satellite (or other hierarchical) structure. The Commission solicits comments on the technical limitations or cost limitations on how large an RTO can be if it is to have control area responsibilities.

The difficulty and cost of transferring operational control over many transmission systems to one RTO may also affect regional configuration. The larger the number of transmission systems, the more complex the task may be and the longer it may take to accomplish. The Commission solicits comments on how the number of transmission systems to be combined would affect the cost and time required to form an RTO.

A third factor that may limit size is rate treatment. As regions get larger and involve more existing owners of transmission, reaching consensus on an appropriate transmission rate design for the region may prove challenging. Also, a uniform transmission rate treatment which averages the costs of existing transmission assets across the region could subject some RTO participants to higher transmission rates. Moreover, sharing the costs of future transmission improvements may raise issues regarding whether the transmission improvements provide benefits to the entire region and who should pay those costs. These issues are discussed further below with respect to cost shifting concerns.

Are there other factors that may limit the geographic scope of an RTO? The Commission solicits comments on this issue.

ii. Factors for Evaluating Boundaries

In addition to the factors affecting the size of a region, other factors may affect the location of regional boundaries. The Commission believes that RTO boundaries should be drawn so as to facilitate and optimize the competitive, reliability, efficiency, and other benefits that RTOs are intended to achieve, as well as to avoid unnecessary disruption to existing institutions. The Commission proposes below a list of factors it would consider in evaluating the configuration for a proposed RTO. Various factors may indicate different configurations, and assessing the appropriateness of a region's configuration will require a balancing of factors.

Given this qualification, the Commission proposes that the following factors should be considered in evaluating an RTO's boundaries:

Facilitate performing essential RTO functions and achieving RTO goals, as discussed elsewhere in this proposed rule: The regions should be configured so that an RTO operating therein can ensure non-discrimination and enhance efficiency in the provision of transmission and ancillary services, maintain and enhance reliability, encourage competitive energy markets, promote overall operating efficiency, and facilitate efficient expansion of the transmission grid. For example, we understand that there have been instances where transmission system reliability was jeopardized due to the lack of adequate real-time communication between separate transmission operators in times of system emergencies. To the extent possible, RTO boundaries should encompass areas for which real-time communication is critical, and unified operation is preferred.

Recognize trading patterns: Given that a goal of this initiative is to promote competition in electricity markets, regions should be configured so as to recognize trading patterns, and be capable of supporting trade over a large area, and not perpetuate unnecessary barriers between energy buyers and sellers. There may exist today some infrastructure or institutional barriers inhibiting trade between regions that could be mitigated economically. It would be desirable that RTO boundaries not perpetuate these barriers.

Not facilitate the exercise of market power. While the industry should work toward a goal of virtually seamless trade between RTOs, it may be that initially a significant amount of trade may be contained within RTOs. Thus, it is important to avoid creating an RTO region that is dominated by a only a few buyers or sellers of energy, or a region where an RTO of inappropriate scope and configuration can exercise transmission market power by acting as an unnecessary toll collector on a critical corridor.

Encompass existing control areas: Existing control areas have established systems for load balancing within their area. Most existing control areas are relatively small. For the sake of efficiency, it may be advisable not to divide them. However, the affected parties would not be precluded from proposing to divide control areas if they found it otherwise advantageous.

Encompass existing regional transmission entities: Because existing ISOs, and any other regional transmission entities we may hereafter approve, already integrate transmission systems, it may not be efficient to divide them into different regions. This is not to say, however, that RTO boundaries must coincide with existing regional transmission entities. An appropriate region may well be larger, and there may be circumstances that support combining or reconfiguring existing entities.

Encompass one contiguous geographic area: The competitive, efficiency, reliability, and other benefits of RTOs can be best achieved if there is one transmission operator in a region. To be most effective, that operator should have control over all transmission facilities within a large geographic area, including the transmission facilities of non-public utility entities. This consideration could preclude a noncontiguous region, or a region with "holes."

Encompass a highly interconnected portion of the grid: To promote reliability and efficiency, portions of the transmission grid that are highly integrated and interdependent should not be divided into separate RTOs. One RTO operating the integrated facilities can better manage the grid. This is not to say, however, that every weak interconnection belongs on a regional boundary. Where a weak interface is frequently constrained and acts as a barrier to trade, it may be appropriate to place that interface within an RTO region. It may be more difficult to expand a weak interface on the boundary between two regions; this may act as a barrier to trade between the two regions. The Commission welcomes comments on the relative merits of internalizing constraints within a region versus having constraints act as natural boundaries between regions.

Take into account existing regional boundaries (e.g. North American Electric Reliability Council (NERC) regions) to the extent consistent with the Commission's goals for RTOs: An RTO's configuration should, to the extent possible, not disrupt existing useful institutions. The Commission recognizes that utilities have been working together regionally in different contexts for some time. There is value in keeping together parties that have been working together.

Take into account international boundaries: The Commission recognizes

[200] The Midwest ISO is the only Commission-approved ISO that has not proposed a single control area.

that natural transmission boundaries do not necessarily coincide with international boundaries. Indeed, a large part of Canada's transmission system, and a small part of Mexico's, is interconnected on a synchronous basis with that of the U.S. Accordingly, an appropriate region need not stop at the international boundary. However, this Commission does not have, and does not seek, jurisdiction over the facilities in a foreign country. We will ask our international neighbors to participate in discussion of these issues. Perhaps what may be thought of as a "dotted line" boundary at the international border could be used to indicate that a natural transmission region does not necessarily stop at the border, while this Commission's jurisdiction does.

The Commission seeks comments on the appropriateness of these factors to determine an appropriate configuration for the regions in which RTOs would operate, and also asks if any additional factors may be appropriate.

b. Potential Geographic Configurations

Any number of RTO configurations could be appropriate regions. One approach to establishing RTO regions is to use existing configurations. These include the three electric interconnections within the continental United States, the ten NERC reliability councils, and the twenty-three NERC security coordinator areas. (*See* Appendix C to this NOPR for depictions of these configurations [201]). These configurations are offered only for the purposes of having three examples for assessing how well selected regions can satisfy the minimum RTO characteristics and functions and for focusing commenters on the trade-offs involved in determining an RTO configuration. The Commission has not concluded that the example sets of boundaries are acceptable configurations. The Commission seeks comments on how well the regions served by existing institutions would satisfy the factors enunciated above, and specifically how well they would be able to satisfy the minimum RTO characteristics and functions outlined in this section, and the advantages and disadvantages of these three examples. The Commission also welcomes presentation and evaluation of other methods to define appropriate regions.

c. Control of Facilities within a Region

In addition to the scope and configuration of the region, effective performance also requires that most or all of the transmission facilities in a region be included in the RTO. Any RTO proposal filed with us should plan to operate all transmission facilities within its proposed region. We recognize, however, that there may be cases where the proponents of an RTO may not be able to obtain agreement by all transmission owners within a region of appropriate scope and configuration to transfer operating control of their facilities to the RTO. This may occur, for example, because certain facilities may be owned by governmental entities that have restrictions on transfer of control that may require time to resolve. We do not believe that it would be desirable to deny RTO status or delay RTO start-up where the transmission owners representing a significant portion of the facilities within a region are ready to move forward, while a few others are not. On the other hand, we do not believe it would be desirable to approve an RTO proposal for a proposed region if the proponents represent only a small portion of the facilities in that region.

We therefore propose to accept as RTOs only those proposals for which a region of appropriate scope and configuration is identified and the proponents represent a sufficient portion of the transmission facilities within the identified region. Where the proponents do not represent all the facilities within a region, they should identify the reasons why all facilities are not represented, any efforts that will be made to eventually include all facilities, and any interim arrangements that could be made with the non-represented facility owners to maximize coordination within the region.

We solicit comments on how best to balance our goal of having RTOs in place that operate all transmission facilities within an appropriately sized and configured region against the reality that there may be difficulties in obtaining 100 percent participation in all regions in the near term. Should we deny RTO status for any proposal that does not include all transmission facilities within an appropriate region? If we do not deny RTO status for less than 100 percent participation, is there some guideline that we should use for determining when the proponents represent an appropriate "critical mass" for the region? Should we require that the RTO at least negotiate certain agreements with any non-participants within its region to ensure maximum coordination? If so, what should be the terms of such agreements?

Finally, we seek comment on the question of how much deference, if any, we should give to the proposed scope and regional configuration of a proposed RTO. How readily, if at all, after balancing all appropriate factors, should the Commission be willing to substitute its vision of an appropriate RTO configuration for that of its proponents? To what extent should the Commission take into account the degree of support in assessing a proposed RTO configuration? Should approval or disapproval by affected state commissions of the scope or configuration of a proposed RTO affect the level of deference the Commission should afford such a proposal?

3. Characteristic 3: Operational Authority. The RTO must have operational responsibility for all transmission facilities under its control.[202] (Proposed § 35.34(i)(3))

a. The Regional Transmission Organization May Choose to Directly Operate Facilities (Direct control), delegate certain tasks to other entities (Functional Control) or Use a Combination of the Two Approaches. (Proposed § 35.34(i)(3)(i))

Operational control raises two basic questions: What functions should be performed by an RTO? How should an RTO perform the functions that it has reserved for itself? With respect to the first question, there is a concern that some splits of functions between an RTO that is an ISO and existing control area operators could compromise reliability and allow the control area operators to continue to favor their own power marketing efforts.[203]

One solution would be for all RTOs to operate a single control area. We have decided not to propose this as a requirement or two reasons. First, the recent experience with the California ISO suggests that the cost of investing in new control centers and telecommunications systems and developing new operating systems can be very high.[204] Second, there is some uncertainty as to whether it is technically feasible to establish a single traditional control area over a large

[201] While the maps in Appendix C accurately depict the existing configurations extending into Canada, this is not intended to suggest that our jurisdiction under this proposed rule reaches there.

[202] Transmission facilities will be distinguished from local distribution facilities using the criteria that were established in Order No. 888. *Order No. 888*, FERC Stats. and Regs. ¶ 31,036 at 31,770–71.

[203] *Midwest ISO*, 84 FERC at 62,156–60, 62,181.

[204] A recent report commissioned by the California ISO found that the higher costs of the California ISO relative to other ISOs could be explained, in part, by the decisions "to build a privately dedicated communications network, to have a hot standby backup center half a state away, to not rely on existing infrastructure more than necessary, to attempt full functionality on day one, to accomplish the job in about one year. . ." *See* "A Comparative Analysis Of Operating Independent System Operators In The United States," prepared by James H. Caldwell Jr. (TGAL, Inc.) For the California ISO, October 15, 1998, at 13.

geographic area. In light of these considerations, we do not propose to require that an RTO must operate a single control area. However, the RTO must have ultimate responsibility for providing non-discriminatory transmission service for all market participants and for ensuring the short-term reliability of the grid.[205] We propose to give an RTO considerable flexibility in deciding on the particular division of operational responsibilities with existing control areas that will allow it to achieve this outcome.

We will also grant an RTO considerable flexibility in deciding how best to perform the functions that it has reserved for itself. The RTO may choose to operate the grid through direct physical operation by RTO employees, contractual agreements with other entities (*e.g.*, transmission owners and control area operators) or combinations of the two. For example, an RTO could lease some control equipment from the owners of existing control centers or convert some employees at these control centers into RTO employees. Or alternatively, the RTO could establish a system of hierarchical control in which it operates a master control center and existing control centers become satellites of the RTO control center for certain specified functions.[206] Under this arrangement, the personnel of the existing control centers might become employees of the RTO or remain as employees of the control center owner but supervised by RTO personnel. We will leave it to the discretion of the RTO to decide on the combination of direct and functional control that works best for its circumstances.[207] Our only requirement is that the system of operational control chosen by the RTO must ensure reliable operation of the grid and non-discriminatory access to the grid by all market participants. In addition, to ensure that the RTO does not become locked into an operational system that is unsatisfactory, the Commission will require an RTO to prepare a public report that assesses the efficacy of its operational arrangements no later than two years after it begins operations.

The Commission requests commenters to address the following questions. What has been the experience of existing tight power pools with master-satellite and hierarchical forms of control? Was there a need to modify these operational arrangements when the pool was replaced by an ISO? Outside of tight power pools, has the functional unbundling requirement in Order No. 888 led to any divisions of previously integrated internal operational systems? If so, have these new divisions of operational responsibilities created any reliability problems?

b. The RTO must be the security coordinator for the transmission facilities that it controls. (Proposed § 35.34(i)(3)(ii))

The Commission will also require that any qualifying RTO be the NERC approved security coordinator for its region. A security coordinator is a new type of grid entity that typically coordinates reliability between multiple control areas across a region. It has been promoted by NERC since 1995 to improve coordination and communication across control areas. At present, there are more than 20 security coordinators.[208]

Up to now, the job of a security coordinator has been to anticipate reliability problems and to take actions to correct these problems if they arise. Among the key functions of a security coordinator are to: (1) perform load-flow and stability studies of the transmission system to identify and address security problems; (2) exchange necessary security information with control area operators, ISOs and regional reliability councils; (3) monitor real-time operating characteristics (*e.g.*, availability of operating reserves, interchange schedules, system frequency, actual flows versus limits, generation capacity deficiencies) that could affect reliability; (4) take appropriate action including, if necessary, the shedding of load in the event of a reliability problem.[209]

In our Midwest ISO order, we required that the proposed ISO must be the security coordinator for its region. Our justification for this requirement was that:

> This role [the role of a security coordinator] is central to maintaining grid reliability and non-discriminatory access. Under proposed NERC policies, security coordinators would be required to anticipate problems that could jeopardize the reliability of the interconnected grid. In the course of performing these reliability functions, the Security Coordinator would receive considerable information which is commercially sensitive. Therefore, it is important that the proposed Midwest ISO Security Coordinator be performed by an entity that is independent of market participants.

The same logic applies to any RTO proposal. Therefore, we will require that a qualifying RTO must be the security coordinator for its region.[210]

4. *Characteristic 4: Short-term Reliability.* The RTO must have exclusive authority for maintaining the short-term reliability of the grid that it operates. (Proposed § 35.34(i)(4))

a. The RTO must have exclusive authority for receiving, confirming and implementing all interchange schedules. (Proposed § 35.34(i)(4)(i))

Historically, interchange schedules have referred to the scheduling actions between adjacent control areas. These schedules could be triggered by the sale or exchange of electricity or the wheeling of electricity between the two control areas. The first type of action, the sale or exchange of electricity between control areas, usually has not been accompanied by a separate transmission transaction. Instead, the transmission service was implicit in the overall transaction and, therefore, its cost was not quoted separately. With the growth of unbundled transmission service, triggered in part by our Order No. 888 requirements, bundled interchange transactions will become rarer. This means that in the future, interchange schedules will generally be accompanied by, and coincide with, transmission schedules.

We are proposing that an RTO "must receive and evaluate all requests for transmission service under its own FERC approved tariff."[211] If the RTO operates a control area, this implies that the RTO will also be receiving, confirming and implementing interchange schedules. Therefore, the three actions should go hand-in-hand for an RTO that operates a control area.

[205] In our order approving the Midwest ISO, we stated that our approval of the ISO was based on the applicants' commitment that the ISO would be able to "take *all* actions necessary to provide nondiscriminatory transmission service, promote and maintain reliability." *Midwest ISO*, 84 FERC at 62,159.

[206] *See, e.g.*, Marija Ilic and Shell Liu, Hierarchical Power System Control: Its Value in a Changing Industry, Springer-Verlag, 1996. It appears that certain types of hierarchical arrangements have operated successfully in the PJM and NEPOOL pools for many years.

[207] This topic is also addressed in our discussion of the RTO's role as a provider of ancillary services. See the discussion of Function 4.

[208] *See* NERC, Operating Policy 9—Security Coordinator Procedures. The current version of this document is available on the NERC website at http://www.nerc.com/~oc/opermanl.html. *See also*, NERC TLR Order, 85 FERC ¶ 61,353 at 62,360–62.

[209] *Midwest ISO*, 84 FERC at 62, 155–56.

[210] We note that this was also the conclusion of the blue-ribbon Electric Reliability Panel of NERC. In its final report, the panel concluded that "it is essential that the security coordinators perform their functions independent of any market influences." The panel recommended that security coordinators should be "structured as independent entities, or their role subsumed into independent system operator-type organizations." NERC, Electric Reliability Panel, "Reliable Power: Renewing the North American Electric Reliability Oversight System," December 1997, at 35.

[211] *See* the discussion of Function 1 (Tariff Administration and Design), *infra*.

However, this may not be the case for RTOs that do not operate control areas. As we stated in our Midwest ISO order, our basic concern is that non-RTO control area operators who are also competitors in power markets may be "able to know their competitors' schedules or transactions* * *"[212] If this is true, such knowledge would give the control area operators an unfair competitive advantage. The Commission directed the ISO to monitor for this potential problem and report to us immediately if the problem arises. We recognize, however, that it may be difficult to detect this discrimination. In addition to our current code of conduct standards, are there any actions that the Commission should require to reduce the likelihood of this problem that do not require the consolidation of all existing control areas within the region? Is it feasible for a non-RTO control area operator, operating within an RTO region, to perform its functions without having access to commercially sensitive information involving its competitors? For example, could an RTO provide control area operators with information about scheduled net interchanges between control areas without disclosing the individual transactions making up the new interchanges?[213]

b. The RTO must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities. (Proposed § 35.34(i)(4)(ii))

As we have stated before, the dividing line "between transmission control and generation control is not always clear because both sets of functions are ultimately required for reliable operation of the overall system."[214] The entity that controls the transmission system must have some degree of control over some generation.[215] In general, we do not think that this authority should extend to initial unit commitment and dispatch decisions of generators. However, the Commission believes that it is necessary and appropriate that the RTO have authority to order redispatch of any generating unit when necessary for the reliability of the grid.

c. When the RTO operates transmission facilities owned by other entities, the RTO must have authority to approve and disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards. (Proposed § 35.34(i)(4)(iii))

Control over transmission maintenance is a necessary RTO function because planned and unplanned outages of individual transmission facilities affect the overall transfer capability of the grid. If a facility is removed from service for any reason, the power flows on all regional facilities are affected. These shifting power flows may cause other facilities to become overloaded, and so adversely affect system reliability. The availability or unavailability of specific transmission facilities can also have major effects on electricity market prices.[216]

Under this proposed requirement, the RTO would determine whether the proposed maintenance of transmission facilities could be accommodated within established state, regional and national reliability standards. The RTO's regional perspective will allow it to coordinate individual maintenance schedules with each other as well as with expected seasonal system demand variations. Since the RTO will have access to extensive information, it will see the "big picture" and be able to make more accurate assessments of the reliability effect of proposed maintenance schedules than individual, sub-regional transmission owners.

If the RTO is a transmission company that owns and operates transmission facilities, these assessments would be an internal company matter. If the RTO is an ISO, it would need to review transmission requests made by various transmission owners (TOs) of its region.[217] In this latter case, we would expect the RTO to: receive requests for authorization of preferred maintenance outage schedules; review and test these schedules against reliability criteria; approve specific requests for scheduled outages; require changes to maintenance schedules when they fail to meet reliability standards; and update and publish maintenance schedules on a regular basis.

The Commission requests commenters to address a number of questions related to this proposed requirement. Does it cede too much or too little authority to the RTO? If the RTO requires a transmission owner to reschedule its planned maintenance, should the transmission owner be compensated for any costs created by the required rescheduling? Would it be feasible to create a market mechanism to induce transmission owners to plan their maintenance so as to minimize reliability effects? Should an RTO that is an ISO have any authority to require rescheduling of maintenance if it anticipates that the planned maintenance schedule will adversely affect power markets? If the RTO is a transco, can it manipulate its transmission maintenance schedules in a manner that harms competition?

The proposed requirement does not give the RTO any authority over proposed generation maintenance schedules. However, in our order approving the Midwest ISO, we observed that "the dividing line between transmission control and generation control is not always clear because both sets of functions are ultimately required for reliable operation of the overall system."[218] Should the RTO have some authority over generation maintenance schedules? If so, how much authority should it have?

We also anticipate that the RTO will need to establish performance standards for transmission facilities under its direct or contractual control. Such standards could take the form of targets for planned and unplanned outages. The rationale for this requirement is that two transmission owners should not receive equal compensation if one owner operates a reliable transmission facility while the other operates an unreliable facility. For RTOs that are transcos, we would anticipate that such quality standards would be implicit or explicit in any performance based regulatory proposal. [219]/ Is it possible for a non-profit ISO to establish similar incentive schemes for the transmission owners whose facilities it operates?

Facility ratings. It is widely recognized that reliable operation of the transmission system in the short-term requires both continuous monitoring of equipment availability and loading, and actions to maintain loading levels within the established operating ranges

[212] *See Midwest ISO*, 84 FERC at 62,154–55.

[213] *See Id.* at 62,160.

[214] Id. at 62,151.

[215] This seems to be generally recognized in the industry. For example, the participants in the Midwest ISO proposed that the ISO "will possess authority over generation to the extent that generation affects transmission." *See* ER98–1438–000, Applicants' Response at 3.

[216] *See* "Staff Report to the FERC on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998," September 22, 1998, at 4–3.

[217] Since some of these transmission owners may also own generation, they may have an incentive to schedule transmission maintenance at times that would increase the prices received from their power sales. A transmission company, not affiliated with any generators, would not have these same incentives.

[218] *Midwest ISO*, 84 FERC at 62,180.

[219] We note that the National Grid Company in England and Wales reports annually on quality of service in certain dimensions (systems availability, interconnector availability, system security and quality of supply) to the Director General of Electricity Supply. *See* National Grid Company "Report of the Director General of Electricity Supply, Financial Year 1997–98." A copy of this report will be placed in the public record.

and equipment ratings. If a transmission line or other facility becomes overloaded or experiences a forced outage, the short-term reliability of the power system may be threatened. Therefore, we anticipate that the RTO will need to monitor equipment availability and loading so that it can determine which control actions or redispatch options are necessary. The options open to the RTO for ensuring short-term reliability, such as direct control of transmission facilities, initiating transmission loading relief procedures or pursuing redispatch options and bids, are discussed in other sections.

To determine whether existing or scheduled power flows will threaten short-term system reliability, flow levels must be compared to ratings established in power flow reliability studies. The entity that establishes these ratings and operating ranges will have a major influence on the reliable operation of the power system. Its determinations will not only affect system reliability but also ATC. The Commission believes that RTOs are best situated to establish ratings and operating ranges for two reasons. First, they will have the most complete information about expected and real-time operating conditions. Second, RTOs will be trusted since they will be independent in two ways: they will not have any economic interests in electricity market outcomes and they will not be owned or controlled by any market participants.

The Commission recognizes that an RTO that is an ISO may initially need to rely upon existing values for equipment ratings and operating ranges so as not to disrupt reliable system operation. The RTO will then have the ongoing task of validating and updating these existing values, focusing initially on those identified as critical to the development of a competitive electricity market.

The Commission understands that transmission owners may be concerned that changes in existing equipment ratings may lead to problems of equipment safety and possible damage. These concerns could trigger disputes over the values established by the RTO. We propose that if there is a dispute over values established for equipment ratings, the RTO values will prevail until the outcome of the dispute resolution process. It is the intent of the Commission to promote RTOs that have the expertise and personnel capable of determining both equipment ratings and operating ranges necessary to maintain system reliability. In addition, since RTOs will be independent of all stakeholders in the electricity market, they will not have an incentive to distort the operation of electricity markets by manipulating equipment ratings and reliability assumptions. And most significantly, since the RTO is ultimately responsible for system reliability, it will be careful not to harm system equipment. Therefore, to avoid an impasse over equipment ratings that are determined by one market participant and contested by a second, we believe that the RTO's values should prevail when there is disagreement, until resolution is reached through an ADR process approved by the Commission.[220]

The Commission asks commenters to address the following issues. Given that an RTO has responsibility for system reliability, what should be the extent of its liability for its actions? Would this differ depending on whether the RTO owns the facilities?

d. If the RTO operates under reliability standards established by another entity (*e.g.*, a regional reliability council), the RTO must report to the Commission if these standards hinder it from providing reliable, non-discriminatory and efficiently priced transmission service. (Proposed § 35.30(i)(4)(iv))

RTOs may be new organizations. However, they will be sharing some of their responsibilities with existing organizations. For example, the New England ISO shares its responsibilities with the NEPOOL RTG.[221] The New York ISO shares its reliability responsibilities with the New York State Reliability Council. We anticipate that, in the near future, RTOs will be implementing reliability standards that are established by a separate regional reliability council.[222] We believe this is necessary to maintain the reliable operation of the grid, but it also raises concerns because almost every reliability standard will have a commercial consequence, and regional or sub-regional reliability groups may not be as independent of market participants as RTOs.[223] As a consequence, an RTO could be required to implement a reliability standard that may favor the commercial interests of certain types of market participants when an equally effective, but more commercially neutral, variant of the standard might be feasible. Therefore, it is important that the RTO notify us immediately if implementation of externally established reliability standards will prevent it from meeting its obligation to provide reliable, non-discriminatory transmission service.

Minimum Functions

1. Function 1: Tariff Administration and Design. The RTO must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities. (Proposed § 35.30(j)(1))

The pro forma open access transmission tariff that accompanied Order No. 888's functional unbundling is based on a traditional approach to transmission service: it relies on embedded cost ratemaking, contract path scheduling and physical rights to service. We recognized that it did not break new ground on transmission pricing because it was based "on the practices and procedures" that were traditionally used by public utilities that owned transmission facilities. Instead, the focus of the pro forma tariff is on the non-price terms and conditions of transmission service needed to get non-discriminatory transmission service. Our intent was to "initiate open access" for individual transmission providers. We stated that our issuance of the pro forma tariff was "* * * not intended to signal a preference for contract path/embedded cost pricing for the future."[224] In the Capacity Reservation Tariff (CRT) NOPR that was issued at the same time, we emphasized that: "* * * the Commission is not committed to traditional tariff design."[225] Since the issuance of Order No. 888, the Commission has encouraged transmission providers to come forward with other open access transmission tariffs that they believe have pricing

[220] This is the same policy that we adopted in approving the Midwest ISO. *See Midwest ISO*, 84 FERC at 62,165–66.

[221] Commissioner Malachowski, representing the New England Conference of Public Utility Commissions (NECPUC), stated that the current sharing of power between the New England ISO and NEPOOL is unsatisfactory. He said that the New England commissions believe that more decision making authority must be transferred to the ISO. As a specific example, the mentioned the need for the ISO to have more direct authority over market design. RTO Conference (Washington, D.C.), transcript at 123.

[222] In Order 888, we required that any ISO should "comply with their applicable standards set by NERC and the regional reliability council." (ISO Principle No. 4)

[223] *See Central Hudson*, 83 FERC at 62,411 for a discussion of our concerns about the relationship between the New York ISO and the New York State Reliability Council. In this instance, we were willing to accept the fact that the NYSRC will establish rules that the ISO would implement because any new rule or revisions to existing rules would be "subject to immediate suspension by the NYSRC if requested to do so by the New York ISO." *Id.*

[224] *Order No. 888*, FERC Stats. & Regs. at 31,666–67.

[225] *CRT NOPR*, FERC Statutes and Regulations at 33,228 (1996).

provisions that are equal or superior to the mandated tariff that was part of the Order No. 888 initiative.

To date, the most significant innovations in transmission access and pricing have been brought to us by ISOs. This is not surprising. Given the interconnectedness of the grid, it is necessary to introduce regional pricing innovations through some kind of regional organization. This cannot be done by individual transmission providers acting alone. We anticipated that regional organizations would be the likely innovators in our Transmission Pricing Policy Statement. Among the innovations that have been proposed since the issuance of Order No. 888 are: locational pricing; fixed transmission rights (FTRs) and transmission congestion contracts (TCCs) that give defined financial rights to grid users (*i.e.*, financial rather than physical rights to the grid); and explicit market-based pricing of congestion and ancillary services.[226] In almost every instance, we have approved these proposals because they offer the promise of promoting overall operating efficiency and encouraging fair, open and competitive energy markets.

Therefore, we take this opportunity to reaffirm the importance of such reform by establishing it as an explicit obligation for qualifying RTOs. The wording of this requirement is general and this is intentional. The Commission believes that RTOs are in the best position at this time to develop innovative transmission access and pricing regimes that will promote competition and meet the needs of their region. The Commission invites commenters to address whether more specific guidance is required.

In carrying out Function 1, the RTO must satisfy each standard discussed below, or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard.

a. The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The Regional Transmission Organization must have the authority to review and approve requests for new interconnections.[227] (Proposed § 35.30(j)(1)(i))

The rationale for this standard is straightforward. The RTO cannot ensure nondiscriminatory transmission service to all market participants unless it is the sole provider of transmission service over facilities that it owns or controls. If it is to be an effective "provider", it must be the only entity that receives, evaluates and approves or denies requests for transmission service. However, it cannot make informed decisions unless it has accurate and unbiased information about pending transmission requests and current system conditions. This, in turn, implies that in addition to being the transmission service provider, the RTO must be the operator of the OASIS site as well as the regional security coordinator (see the discussion of function 5 and characteristic 3).

An organization like an independent scheduling administrator that simply monitors the scheduling decisions of current transmission owners and offers dispute resolution services in case of a dispute would not qualify as an RTO. Similarly, a transmission organization that offers service under another entity's tariff would not meet this standard.

An RTO's obligation to provide nondiscriminatory transmission service is not limited just to existing users. It is important that the RTO ensures nondiscriminatory access to transmission service for new entrants such as new generators. This requires that the RTO, rather than existing transmission owners, have the authority to review and approve requests for interconnections. The Commission believes that the RTO cannot be an effective provider of transmission service if it lacks the authority to ensure that new customers are interconnected to the grid. This standard should be relatively easy to implement for an RTO that owns transmission facilities. However, it may be more difficult for an RTO that does not own transmission facilities because actual physical construction of the interconnection facilities will usually be made by an existing transmission owner who may also be a competitor of the new generator. Therefore, the Commission invites comments on how this standard can be made effective for RTOs that are ISOs. Are there lessons to be learned from the experience of qualifying facilities (QFs) under PURPA in getting interconnections to the grid that would be applicable to ISOs? Should this standard be expanded to give the RTO the authority to review and approve all new interconnections (*e.g.*, to connect new generators, to improve reliability, to increase trading opportunities with neighboring regions) or all transmission investments above some threshold dollar amount?

b. The RTO tariff must not result in transmission customers paying multiple access charges to recover capital costs over facilities that it controls (*i.e.*, no pancaking of transmission access charges). (Proposed § 35.34(j)(1)(ii))

The elimination of transmission rate pancaking for large regions is a central goal of the Commission's RTO policy. Therefore, the offering of non-pancaked transmission access charges is a requirement for a conforming RTO. In the existing world of many individual transmission service providers, transmission customers have generally been required to pay an access charge to each transmission provider along the contract path (and pay nothing to providers off the contract path). This is a form of distance-based transmission pricing, but the charge is a function of corporate boundaries crossed on the contract path rather than distance traveled on actual flow paths. Such pancaked transmission charges have led to multiple transmission charges across several transmission systems and make it difficult to create region-wide power markets. Competition is clearly enhanced when customers are able to access larger numbers of generators over a wide geographic region when they pay a single transmission access charge. In Order No. 888, we required tight power pools and holding companies to offer a system-wide tariff with non-pancaked rates.[228] To date, non-pancaked transmission access charges have been a feature of all five ISOs that we have approved. In this NOPR, we are proposing to extend that requirement to RTOs.

[226] *See, e.g., Pacific Gas & Electric,* 81 FERC ¶ 61,122 (1997), *Central Hudson,* 83 FERC ¶ 61,352 (1998), *NEPOOL,* 85 FERC ¶ 61,242 (1998); *PJM;* 81 FERC ¶ 61,257 (1997).

[227] The Commission, of course, retains ultimate authority to order transmission services and interconnections pursuant to the FPA.

[228] *Order No. 888,* FERC Stats. & Regs. at 31,727–29, 31,731.

Would the requirement for a tariff with non-pancaked rates make the voluntary formation of RTOs more difficult because it might result in the potential for sudden and unacceptable transmission rate charges? Is the severity of any such problem related to the scope and regional configuration of the proposed RTO? Does the use of so-called license plate design allow the RTO to meet this requirement without cost shifting? Would the provision for a reasonable transition period help?

Waiving of access charges. While the Commission wishes to encourage more efficient intra-regional trade, it also would like to encourage inter-regional trade. Boundaries are always a potential impediment to trade, whether between states, RTOs or countries. Therefore, we encourage RTOs to negotiate the mutual waiving of transmission access charges to increase the size of effective trading areas. In the Midwest ISO proceeding, we were told that this was difficult to implement.[229] Therefore, commenters are requested to recommend actions that the Commission could take to facilitate reciprocal waiving of access charges. Even if there is mutual waiving of access charges, are there other pricing impediments to inter-regional trade (*e.g.*, differences in scheduling and curtailment conventions between regions) that are likely to impede trade?

2. Function 2: Congestion Management. The RTO must ensure the development and operation of market mechanisms to manage transmission congestion. (Proposed § 35.34(j)(2)).

In carrying out Function 2, the RTO must satisfy each standard discussed below, or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard.

a. The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals regarding the consequences of their transmission usage decisions. The RTO must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant. (Proposed § 35.34(j)(2)(i))

As we stated in our recent order addressing NERC's transmission loading relief (TLR) procedures, the traditional approaches to congestion management may no longer be acceptable in a competitive, vertically de-integrated industry.[230] For example, the use of administrative curtailment procedures has important economic consequences for market participants, yet such procedures are usually invoked without regard to the relative value of transactions that are curtailed. This can lead to a considerable disruption of power markets and can be financially damaging for market participants. The Commission has concluded that efficient congestion management requires a greater reliance on market mechanisms.[231] Recent experience suggests that only a large regional organization like an RTO will be able to create a workable and effective congestion management market.[232]

As we noted in our order approving the PJM ISO, markets that are based on locational marginal pricing and financial rights for firm transmission service provide a sound framework for efficient congestion management.[233] However, just as we do not intend to mandate a single corporate form for RTOs, we will not require one specific market approach to congestion management. It is our intent to give RTOs considerable flexibility in experimenting with different market approaches to managing congestion. However, we believe that a workable market approach to congestion management should generally establish clear and tradeable rights for transmission usage, promote efficient regional dispatch, support the emergence of secondary markets for transmission rights, and provide market participants with the opportunity to hedge locational differences in energy prices.

A market approach to congestion management should lead to more efficient transmission prices. As we explained in our Transmission Pricing Policy Statement, an efficient pricing policy must meet certain objectives.[234] Of the four objectives set forth in the Policy Statement, two are particularly relevant for congestion management. First, the generators that are dispatched in the presence of transmission constraints should be those that can serve system loads at least cost, given the constraints. Second, given that the demand for transmission services during periods of congestion exceeds the system's ability to supply them, the limited transmission capacity should be used by market participants that value that use most highly.

In designing market mechanisms for congestion management, the Commission recognizes that it is important to consider the time frame in which decisions must be made and actions must be taken. It is the nature of electric systems that operating conditions, including those that lead to the presence or absence of congestion, are constantly changing. Thus, to manage congestion efficiently while ensuring safety and reliability, system operators must be able to take decisive action quickly.

One possible implication of this need for quick, decisive action is that markets that directly support congestion management may have to be subject to some coordination by the RTO. For example, a congestion market that is not coordinated by the RTO might require transmission customers to negotiate individually with generators to pre-arrange an alternative dispatch that would allow the transmission customer's transaction to proceed (or to be efficiently altered) if and when congestion arises. However, because congestion can occur suddenly and unexpectedly, time may not permit the operator to (1) identify impending transmission constraints, (2) inform customers whose transactions are affected, (3) allow customers to contact generators, and (4) receive instructions from customers as to what actions they wish the operator to take with respect to their pending transactions. We have expressed concerns that such a process may be unwieldy and even unworkable in the limited time in which operators must act.[235] Although the process could be simplified by completing some of these activities in advance, such simplifications may come at the cost of eliminating some potentially efficient options.

The Commission invites comments on our requirement that RTOs must be responsible for managing congestion with a market mechanism. Can

[229] *See* Response of Midwest ISO Participants, May 1, 1998, at 11–13.

[230] *See NERC*, 85 FERC at 62,364.

[231] *Id.*

[232] The recent experience of Commonwealth Edison suggests that redispatch markets operated by individual utilities will not be able to elicit an adequate response by generators. After six months of an experimental program, Commonwealth concluded that it is "difficult for one transmission owner to identify and implement redispatch" when the physical limitations and cost effective options for relief are on other transmission systems. According to Commonwealth, the only viable solution would be for the redispatch market to be operated by a regional transmission system operator. *See* Commonwealth Edison, Interim Report on Non-Firm Redispatch, Docket No. ER98-2279, December 17, 1998, at 4 and 10.

[233] *See, e.g., PJM*, FERC 62,252–53.

[234] *Transmission Pricing Policy Statement*, FERC Stats. & Regs. at 31,140–44.

[235] We expressed similar concerns in our order authorizing the formation of the Midwest ISO. *See Midwest ISO*, 84 FERC at 62,165–66. Nevertheless, we opted to allow the Midwest ISO to go forward with its proposal in order to gain actual operating experience.

decentralized markets for congestion management be made to work effectively and quickly? Can the RTO's role be limited to that of a facilitator that simply brings together market participants for the purpose of engaging in bilateral transactions to relieve congestion? If not, will these markets require centralized operation by the RTO or some other independent entity? How can an RTO ensure that enough generators will participate in the congestion management market to make possible a least-cost dispatch? Are there any special considerations in evaluating market power in a congestion market operated or facilitated by an RTO?

We propose that the congestion management function need not necessarily be in place on the first day of RTO operation, and propose to allow up to one year after start-up for this function to be implemented. We recognize that the new approaches to congestion management called for by newly competitive markets may take additional time to work out. We seek comment on whether such an additional implementation time period is warranted, and whether one year is an appropriate additional time period.

3. Function 3: Parallel Path Flow. The RTO must develop and implement procedures to address parallel path flow issues within its region and with other regions. The RTO must satisfy this requirement with respect to coordination with other regions no later than three years after it commences initial operation. (Proposed § 35.34(j)(3))

Many power sales and transmission service contracts are written under the assumption that the power delivered will flow on a particular contract path. This relatively straightforward and easy to administer "contract path" approach assumes that it is possible to determine and fix the path through the transmission network along which power will flow from source to sink. However, this assumption often does not accurately reflect what actually occurs because the scheduled power transfer will flow across the interconnected electrical path between source and destination according to laws of physics, which means that some power may flow over the lines of adjoining transmission systems. This power flow effect is commonly referred to as "parallel path flow" or "loop flow."

Parallel path flows have the potential to create, and have in the past created, disputes among transmission system owners. There are efficiency and economic equity issues involved when a scheduled transaction in fact causes power flows over the facilities of an entity that is not compensated, or when the costs of mitigating parallel flows are allocated to various transmission owners.[236] There are also reliability issues involved when parallel path flows overload a transmission line, and decisions must be made as to what actions to take, and who should bear responsibility for taking necessary steps to unload that line.[237] The interdependent nature of electricity flow implies that one party's ability to transmit energy will depend upon the actions of others, and, for scheduling and pricing purposes, the capacity of the entire network and not just individual systems is the most important factor.[238]

The Commission has previously expressed its view that the issues surrounding parallel path flow are best resolved by mutual arrangements between the utilities that have chosen to interconnect.[239] More recently, the Commission directed all public utilities in the Eastern Interconnection to file an interim redispatch plan if they are not currently participating in a regional congestion management program through a power pool.[240]

The Commission believes that the formation of RTOs, with their widened geographic scope of transmission scheduling and expanded coverage of uniform transmission pricing structures provides an opportunity to "internalize" most, if not all, of the effect of parallel path/loop flow in their scheduling and pricing processes within a region. In particular, we believe that RTO access to region-wide information on network conditions and power transactions, coupled with efficient congestion management and well specified physical and financial transmission usage rights, could help RTOs, as regional grid managers, in taking preemptive action against curtailment incidents that would otherwise be induced by parallel path/loop flow loading of critical transmission facilities. We anticipate that parallel path/loop flow related disputes will diminish to the extent that RTOs are relatively large and able to implement more realistic scheduling and pricing procedures that subsume the effect of parallel path/loop flow within their regions.

We propose that measures to address parallel path flow may not necessarily be in place on the first day of RTO operation, and propose to allow up to three years after start-up for this function to be implemented. We seek comment on whether such an additional implementation time period is warranted, and whether three years is an appropriate additional time period.

4. Function 4: Ancillary Services. An RTO must serve as the supplier of last resort of all ancillary services required by Order No. 888, FERC Stats. & Regs. ¶31,038 (Final Rule on Open Access and Stranded Costs), and subsequent orders. (Proposed § 35.34(j)(4))

In carrying out Function 4, the RTO must satisfy each standard discussed below, or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard.

a. All market participants must have the option of self-supplying or acquiring ancillary services from third parties subject to any general restrictions imposed by the Commissions's ancillary services regulations in Order No. 888, FERC Stats. & Regs. ¶ 31,038 (Final Rule on Open Access and Stranded Costs), and subsequent orders. (Proposed § 35.34(j)(4)(i))

An RTO is a transmission provider and therefore is subject to the general requirements established by the Commission for the provision of ancillary services under Order Nos. 888 and 889 and succeeding orders. Specifically, these require that the transmission provider must provide or cause to be provided six ancillary services on an unbundled basis.[241] Of the six ancillary services, a transmission customer is obligated to purchase two of the services from the transmission provider (the RTO)—scheduling, system control and dispatch service and reactive supply and voltage control from generation. For the remaining four services, a transmission customer has the option of self-providing these services, either by acquiring them from

[236] *See* Indiana Michigan Power Company and Ohio Power Company, 64 FERC ¶ 61,184 (1993) (*Indiana Michigan*) (complaint that 95% of a power sale flowed over transmission system that was not compensated); Southern California Edison Company, *et al.*, 73 FERC ¶ 61,219 (1995) (*Southern California*) (Commission approved plan for mitigating loop flows within the WSSC).

[237] *See NERC*, 85 FERC ¶ 61,353 (1998).

[238] The Order No. 888 *pro forma* open access tariff does not explicitly recognize the effect of parallel path/loop flow.

[239] *See Indiana Michigan*, 64 FERC at 62,554.

[240] *NERC*, 85 FERC at 62,363–64.

[241] The six ancillary services are: (1) Scheduling, System Control and Dispatching Service; (2) Reactive Supply and Voltage Control from Generation Sources Service; (3) Regulation and Frequency Response Service; (4) Energy Imbalance Service; (5) Operating Reserve-Spinning Reservice; and (6) Operating Reserve-Supplemental Reserve Service. *Order No. 888*, FERC Stats. & Regs. at 31,706–17; *Order No. 888–A*, FERC Stats. & Regs. at 30,227–34.

a third party or providing them from the customer's own resources.

Our rationale for imposing the ultimate supply obligation on the RTO is that not all transmission customers may be equally able to self-supply (some own generation, others do not) and that in many circumstances it may be more efficient (i.e., less costly) for the RTO to provide the service for all transmission users on an aggregated basis. Our rationale for allowing self-supply is that it provides a possible competitive check on the RTO to ensure that it acquires the services at lowest cost. In addition, the Commission believes, as a matter of policy, that legal monopolies should not be granted (i.e., serving as the sole provider of ancillary services) unless they are natural monopolies.

The ancillary services policies in Order Nos. 888 and 889 were developed for transmission providers that were generally vertically integrated utilities. There was an expectation that they would be able to provide many of the generation based ancillary services from their own generating resources. An RTO by definition will not own any generating resources. Does this difference necessitate a different set of ancillary service requirements for RTOs? Are there other ancillary services, in addition to scheduling, system control and dispatch, and reactive supply and voltage control from generation sources, for which the self-supply option should be eliminated? Under what circumstances can the RTO's obligation as the ancillary services supplier of last resort be eliminated?

b. The RTO must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All ancillary service providers must be subject to direct or indirect operational control by the RTO. The RTO must promote the development of competitive markets for ancillary services whenever feasible. (Proposed § 35.34(j)(4)(ii))

This policy would, in effect, grant RTOs the exclusive right, subject to national and regional reliability norms, to determine the quantities and, in some instances, the locations at which certain ancillary services must be provided. It would also require that the RTO be able to exercise complete operational control, either directly or indirectly, over any supplier of ancillary services.

Direct control (sometimes referred to as hands-on control or actual physical operation) would require, for example, that RTO employees "push the button" or that RTO computers send instructions directly to generating units or other facilities to take certain physical actions. Automatic generation control (AGC) might be one example of direct control. If the RTO has direct control, it would have authority, by contract or other means, to send direct electronic signals to those generators who have offered, in return for a payment, to increase or decrease the output of their units in response to the RTO's signals. Indirect control (sometimes referred to as functional control, directed control or contractual control) requires that the RTO send instructions to the owner of the facility who then, in turn, performs the actual physical actions to implement these instructions. Indirect control usually requires that there be a contractual agreement between the RTO and the owner of the facilities that has agreed to provide ancillary services.

The Commission requests commenters to address whether these are minimum requirements needed to ensure that the RTO can satisfy its obligation to maintain targeted levels of reliability. Would it be feasible for the RTO to maintain reliability with less authority?

In our Midwest ISO order, we stated that the ISO "* * * should use competitive procurement for all services needed to operate the system." [242] This general requirement would apply to ancillary services since they are clearly needed to operate a reliable bulk power system. One prerequisite for competitive procurement is a competitive market.[243] The Commission would anticipate that many of the generation-based ancillary services (*e.g.*, balancing and reserves) could be acquired in short-term markets that would operate in parallel to basic energy markets.[244] This has been the approach taken by most of the ISOs that we have approved and we see no reason why this would be different for transcos or other types of RTO entities. Other services such as black start capability and voltage support are probably best acquired in long-term markets where potential suppliers would compete for the right to enter into a long-term contract with the RTO. Apart from establishing the general requirement to use competitive markets, the Commission believes that it is best to leave many of the detailed market design questions to the individual RTOs with case-by-case review by us.[245] As we noted earlier, we intend to permit regional flexibility and encourage experimentation. Such experimentation would be discouraged if we issued regulations that are too detailed.

The Commission believes that, whenever it is economically feasible, it is important for the RTO to provide accurate price signals that reflect the costs of supplying ancillary services to particular customers. Accurate price signals are especially important because some of the RTO's customers may be competing against each other in other power sales markets. It is important that the RTO's actions not distort regional power market competition by charging potential competitors inaccurate prices for ancillary services that they purchase from the RTO.

c. The RTO must ensure that its transmission customers have access to a real-time balancing market. The RTO must either develop and operate such markets itself or ensure that this task is performed by another entity that is not affiliated with any market participant. (Proposed § 35.34(j)(4)(iii))

Real-time balancing refers to the moment-to-moment matching of loads and generation on a system-wide basis. It is a function that control area operators must perform to maintain frequency at 60 hz. Real-time balancing is usually achieved through the direct control of select generators (and, in some cases, loads) who increase or decrease their output (or consumption in the case of loads) in response to instructions from the system operator. Over the last two years, the Commission has seen an increasing use by system operators of market mechanisms that rely on bids from generators to achieve

[242] *See* Midwest ISO, 84 FERC ¶ 61,231 at 62,164 (1998).

[243] However, we recognize that the existence of a competitive supply market for ancillary services is no guarantee that the RTO will automatically buy efficiently. Therefore, since the RTO may be the de facto buyer of many of these services, the Commission is receptive to performance-based regulatory proposals that would give RTOs explicit incentives to be efficient buyers of ancillary services. *See* section III.F.

[244] *See* Eric Hirst and Brendan Kirby, Unbundling Generation and Transmission Services for Competitive Electricity Markets, a report prepared for the National Regulatory Research Institute (NRRI 98-05), January 1998.

[245] These would include design issues such as: Are ancillary service bids received before, after or at the same time as energy market bids? Do ancillary service markets clear simultaneously or sequentially? Must the RTO publicly announce the amount of each ancillary service that it needs prior to bidding? What do generators bid (capacity, energy or both)? If there are multiple bid components, are they evaluated together or separately? Should the RTO acquire ancillary services from outside its region? These are some of the design issues that have arisen in the operation of ancillary markets by the California ISO. We expect that there will be other design issues as other ancillary market proposals are presented to us.

overall, real-time balancing.[246] Since system-wide balancing is a critical element of reliable short-term grid operation, we will require that it be a responsibility of the RTO. The Commission would expect that an RTO will perform the overall system balancing function directly if it operates a control area or indirectly if it supervises the operation of sub-regional control areas.

A separate, but related, issue is balancing by individual grid users. The fact that the overall system must be in balance to maintain frequency does not necessarily require that there be a moment-to-moment balance between the individual loads and resources of bilateral traders and load-serving entities and the schedules and actual production of individual generators. Imbalances are inevitable since generators do not exactly meet their schedules and loads always vary from moment-to-moment.

As we noted in the Midwest ISO order, unequal access to balancing options for individual customers can lead to unequal access in the quality of transmission service available to different customers. This could be a significant problem for RTOs that serve some customers who operate control areas and other customers who do not. Under current NERC regulations, control area operators have access to inadvertent energy accounts so they can pay back imbalances in kind and thereby avoid any penalties.[247] In contrast, non-control area transmission customers do not have access to such accounts. Instead, under the pro forma tariff, load serving entities are subject to a deadband and then penalties if the magnitude of their imbalances fall outside the deadband. Our concern, as we stated in our Midwest ISO order, is that "nondiscriminatory access would suffer" under such a system.[248] Therefore, the Commission proposes to require that RTOs operate a real-time balancing market that would be available to all transmission customers, or ensure that this task is performed by another entity not affiliated with market participants.[249]

The Commission believes that it is important to give RTOs considerable discretion in how such a market would be operated. An RTO may choose to operate the market itself or assign the task to another entity (*e.g.*, a for-profit exchange) that would operate the market under the RTO's supervision. In addition, the Commission would expect that the design of such a market will necessarily vary between RTOs that operate control areas and those that do not. However, in those instances where RTO does not operate a control area, the RTO must be especially vigilant that transmission customers who continue to operate control areas cannot use that functional responsibility to the disadvantage of non-control area customers.[250]

The Commission invites comments on the use of market mechanisms to support overall system balancing and imbalances of individual transmission users. Is it feasible to rely on markets to support a function that is so time-sensitive? Can such markets be made to function efficiently if the RTO is not a control area operator? For the imbalances of individual transmission customers, should a distinction be made between loads and generators? Should customers have the option of paying for all imbalances in such a market or only imbalances within a specified band?

5. Function 5: OASIS and TTC and ATC. The RTO must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC. (Proposed § 35.34(j)(5))

The operation of an OASIS site has many dimensions. For example, it includes specific practices and terminology. In response to a consensus request from the industry, we recently issued a NOPR that proposes to standardize various practices and terms. The focus of that NOPR is on standardization of protocols for posting, naming and responding to posted information.[251] Apart from these practices, the central and probably most controversial aspect of OASIS operation is the calculation and posting of ATC numbers. The calculation of ATC depends, in turn, on the calculation of TTC.[252] These calculations are different from business practices in that the focus is on content rather than procedures and practices. There is widespread dissatisfaction with the reliability of posted ATC numbers. The Commission has received formal and informal complaints from transmission customers stating that they cannot rely on posted ATC numbers. Criticisms of posted ATC numbers have also been the subject of a widely publicized report issued by a major industry group.[253] It is been alleged that transmission providers who also compete in power markets against their competitors have both the incentive and ability to post unreliable ATC numbers.[254]

We recognize that an individual transmission provider may post ATC numbers on OASIS in good faith only to find that the projected capability does not exist because of scheduling decisions taken by other transmission providers elsewhere on the grid. In such circumstances, transmission providers are not acting unscrupulously. Instead, the problem is simply a mismatch between information flows and electrical flows. Regional transmission organizations that perform ATC calculations based on complete and timely information would tend to eliminate this problem. This seems to be supported by fact that the Commission has received very few complaints about ATC calculations made by ISOs.

The essential feature of our proposed requirement is that the RTO become the administrator of a single OASIS site for all transmission facilities over which it is the transmission provider. This is consistent with earlier orders.[255] Moreover, every ISO that we have approved so far has become the OASIS site administrator for the customers that it serves. However, we recognize that this generally stated requirement inevitably raises questions as to the level of RTO involvement in ATC calculations. An RTO could be involved in ATC calculations at three general levels. At Level 1, the RTO's role would be limited to receiving and posting ATC numbers received from transmission owners. At Level 2, the RTO would receive raw data from transmission

[246] *See Pacific Gas & Electric,* 81 FERC ¶ 61,122 (1997), *Central Hudson,* 83 FERC ¶ 61,352 (1998), *NEPOOL,* 85 FERC ¶ 61,242 (1998); *PJM,* 81 FERC ¶ 61,257 (1997).

[247] NERC Operating Manual, at P1–9.

[248] Midwest ISO, 84 FERC at 62,155.

[249] We have already approved such markets for four ISOs. *See e.g.,* PJM Interconnection, L.L.C., Order Accepting In Part and Rejecting In Part Proposed Revisions To Rate Schedules, September 16, 1998 and New England Power Pool, "Order Conditionally Accepting Market Rules and Conditionally Approving Market Based Rates, 85 FERC ¶ 61,379 (1998). These markets generally allow all transmission customers to settle their imbalances at real time energy market prices. We note that participants in the Midwest ISO have issued a request for proposals that could lead to the establishment of such a market in their region. *See* Solicitation of Interest, Creation of an Independent Power Exchange for the U.S. Midwest, Joint Committee for the Development of a Midwest Independent Power Exchange (Feb. 5, 1999).

[250] *See Midwest ISO,* 84 FERC at 62,159–160.

[251] Open Access Same-Time Information System, Notice of Proposed Rulemaking, FERC Statutes and Regulations ¶ 32,531 (1998).

[252] *See* section III.A.1 for definitions of these terms.

[253] Commercial Practices Working Group and the OASIS How Working Group, "Industry Report to the Federal Energy Regulatory Commission on the Future of OASIS, October 31, 1997.

[254] This is discussed more fully in Section III.A.

[255] In the Primergy merger order, we required that the proposed ISO should be "responsible for calculating ATC." *See* Primergy, 79 FERC ¶ 61,158, May 14, 1997.

owners and centrally calculate ATC values. At Level 3, the RTO would centrally calculate ATC values on data partially or totally developed by the RTO. The proposed requirement that the RTO be the OASIS site administrator is based on the expectation that the RTO will operate at Level 3.

The RTO must eventually operate at Level 3 to ensure that ATC values are based on accurate information that is based on consistent assumptions and to minimize the opportunities for conscious manipulation. In general, the RTO must perform all the calculations and studies necessary to develop the underlying data. When data are supplied by others, the RTO must create a system for regularly validating the data for accuracy and assumptions. If there is a dispute over ATC values, the RTO's values should be used pending the outcome of the dispute resolution process.[256] The RTO must also establish the operating standards (subject to regional and national reliability requirements) underlying the ATC calculations.

6. *Function 6: Market Monitoring.* The RTO must monitor markets for transmission services, ancillary services and bulk power to identify design flaws and market power and propose appropriate remedial actions. (Proposed § 35.34(j)(6))

In carrying out Function No. 6, the RTO must satisfy each standard discussed below, or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard.

a. The RTO must monitor markets for transmission service and the behavior of transmission owners, if any, to determine if their actions hinder the RTO in providing reliable, efficient and nondiscriminatory transmission service. (Proposed § 35.34(j)(6)(i))

b. The RTO must monitor markets for ancillary services and bulk power. This obligation is limited to markets that the RTO operates. (Proposed § 35.34(j)(6)(ii))

c. The RTO must periodically assess how behavior in markets operated by others (*e.g.*, bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects RTO operations and conversely how RTO operations affect the performance of power markets operated by others. (Proposed § 35.34(j)(6)(iii))

The RTO's role as market monitor. To date, the Commission has found monitoring to be essential in helping to ensure non-discrimination and efficiency in the provision of transmission and ancillary services; encourage fair, open, and competitive energy markets; and promote overall operating efficiency.[257] As we stated in the New England ISO order, "markets are likely to evolve in ways that may not be totally anticipated. To ensure that the markets operate competitively and efficiently, it is important that any problems involving market power or market design are quickly identified so that appropriate solutions can be crafted."[258] To date, we have been willing to use ISOs, or their independent monitoring organizations, as a "first line of defense" in detecting both market power abuses and market design flaws.

The proposed requirements are arguably based on the presumption that an RTO will be a non-profit, system operator that does not own any facilities. The requirements may not be appropriate for a for-profit transco that owns the facilities that it operates.[259] Therefore, a threshold question is: what should be the market monitoring role, if any, of an independent, for-profit transco? Is it reasonable to expect that such an RTO could be objective in its assessments? If the RTO is an ISO, do its monitoring activities need to be further insulated to ensure independence and objectivity? For example, should monitoring be performed by one or more individuals or organizations that are funded by the RTO but that have the right to issue reports without the RTO's approval?

The Commission believes that RTOs that are ISOs have a significant comparative advantage over other entities in monitoring markets.[260] First, RTOs have access to considerable information about market conduct and performance. For example, we would expect that an RTO, in the normal course of business, will develop or receive information on quantities of bulk power and transmission services bought and sold by different market participants, expected and real time transmission system conditions, planned maintenance of both generation and transmission facilities and anticipated and real time patterns of load and generation. Second, RTOs will be completely independent of all market participants. For these reasons, the Commission believes that we and our colleagues in state commissions can have great confidence in the RTO market assessments.[261] Our early experience with market assessments performed by the New England and California ISOs has been encouraging. The assessments have been comprehensive and objective even to the point of criticizing past actions by the ISOs themselves.[262]

Despite the advantages of better information and incentives, the Commission believes that it is neither fair nor feasible to impose a monitoring obligation on RTOs for markets that they do not operate. Our preliminary assessment is that it would be difficult for an RTO to monitor a market in which it does not have information on prices, bidding patterns and marginal costs. However, our experience with ISOs has shown that markets for power, ancillary services and transmission service are inextricably intertwined regardless of how they are organized or who operates them.[263] Therefore, we are proposing a middle ground for monitoring regional markets not operated by the RTO. The RTO's monitoring of markets operated by others will be limited to assessing how behavior in these markets affects RTO markets and operations and conversely how RTO markets and operations affect these other markets.

The Commission also recognizes that any markets, whether operated by the RTO or others, will inevitably be affected by basic structural characteristics such as the existing pattern of ownership and control of generation and transmission facilities. Such characteristics are often beyond the control of the RTO. Since our overarching goal in promoting RTOs is to promote fair, open and competitive electricity markets, we and our state commission colleagues need to understand how these structural features affect the potential for competition. Therefore, we propose to require RTOs to provide periodic assessments as to the effect of existing structural conditions on the competitiveness of their region's

[256] This is the same requirement that the Commission imposed on the Midwest ISO. *See Midwest ISO*, 84 FERC at 62,154.

[257] *Pacific Gas & Electric*, 81 FERC at 61,552; *PJM*, 81 FERC at 62,282; *NEPOOL*, 85 FERC at 62,479–480; *Midwest ISO*, 84 FERC at 62,180–181.

[258] New England ISO, 85 FERC ¶ 62,379 at 62,479–480 (1998).

[259] We note that at least one entity that is contemplating the creation of a for-profit transmission company has proposed that this company would perform a market monitoring function. *See* Statement of Mr. Frank Gallaher on behalf of Entergy Corporation, Regional ISO Conference (New Orleans), transcript at 18.

[260] *See Midwest ISO*, 84 FERC at 62,181.

[261] The early experience with market assessments in California and New England seems to support this conclusion. *See* AES Redondo Beach, *et al.*, 85 FERC ¶ 61,123 at 61,462 (1998).

[262] *See* Peter Cramton and Robert Wilson, A Review of ISO New England's Proposed Market Rules, Docket No. ER97–1079, September 9, 1998, and the California ISO Market Surveillance Committee's Preliminary Report On the Operation of the Ancillary Services Markets., Docket No. ER98–2843, August 19, 1998 Markets.

[263] *See* AES Redondo Beach, *et al.*, 85 FERC ¶ 61,123 at 61,453 and 61,459–460 (1998).

electricity markets. Of all the industry organizations that may exist in a region, we think that an RTO is best suited to make this assessment because of its first hand knowledge of day-to-day grid and generation operations and its independence.

The Commission requests comments on several threshold issues related to these proposed market monitoring requirements. Some argue that RTOs should not be charged with any monitoring responsibilities particularly with respect to market power abuses.[264] They argue that the antitrust laws and the Commission offer sufficient protection against competitive abuses. Others have argued that RTOS are somewhat akin to organized stock exchanges and that the Commission should follow the SEC precedent of requiring extensive and sophisticated market monitoring by all of the organized exchanges. Are there features of electricity and transmission markets that argue for imposing similar market monitoring responsibilities on RTOs?

If the Commission decides to require RTOs to provide some form of market monitoring, there are several other questions that arise. Should the Commission rely on RTOs as the "first line of defense" for detecting both design flaws and market power abuses? If this were our approach, what would be an appropriate role for the Commission in market monitoring? If the RTO is operating one or more markets (*e.g.*, ancillary services), is it reasonable to expect that it can perform an objective self-assessment? Is there a difference in the market monitoring that the Commission can expect from RTOs? For example, if the RTO proposes to take a market position in secondary transmission rights, is it plausible to expect that the RTO can perform an objective assessment of this market? Since the success of retail competition will often depend critically on the actions of RTOs, what should be the role of state commissions in market monitoring?

Scope of monitoring activities: design flaws. In observing the experience of ISOs over the last year, we have learned that new market designs almost inevitably include design flaws that become apparent only after the markets begin operation.[265] Often these problems arise because of unexpected interactions between different related markets and unanticipated incentives for buyers and sellers. Electricity market restructuring in other countries has also experienced the need to make many revisions to market designs and rules.[266] These experiences indicate that monitoring is essential to ensure that the markets and structures evolve to ensure just and reasonable rates to consumers. The Commission recognizes that market monitoring can be expensive. We would welcome estimates of the amount of money spent by ISOs to monitor markets and their assessments as to whether they will need to spend more or less money in the future.

Scope of monitoring activities: market power abuses. As we have noted before, it is often difficult to predict whether certain entities will have market power in the future. This is especially true in new markets which operate with new participants and new transmission flow patterns. In situations like this, the past is often not a very good predictor of the future. As a consequence, the Commission has found that in certain situations the better approach is to institute an effective monitoring plan rather than to debate numerous assumptions and projections that inevitably underlie competing market power analyses.[267] For abuses that arise from market power, should the RTO's role be limited to detecting and describing the abuses? In the case of localized market power (*e.g.*, generating units that must run for reliability reasons), should the RTO have the authority to take corrective actions? If the market power has structural causes, what role should the RTO have in developing structural solutions? Should RTOs that are ISOs be required to make regular assessments as to whether they have sufficient operational authority?

Sanctions and penalties. The Commission seeks comment on whether RTOs should be allowed to impose penalties and sanctions. Should the penalties be limited to violations of RTO rules and procedures? Should the RTO be allowed to impose penalties for the exercise of market power? How much discretion should the RTO have in setting penalties? For example, should the RTO's penalty authority be limited to collecting liquidated damages?

d. The RTO must provide reports on market power abuses and market design flaws to the Commission and affected regulatory authorities. The reports must contain specific recommendations about how observed market power abuses and market flaws can be corrected. (Proposed § 35.34(j)(6)(iv)).

In order for regulatory agencies, interested parties and the general public to benefit from monitoring activities, regular reporting of findings is critical. Other than this general requirement, we do not propose at this time to establish detailed standards on the format, length and content of monitoring reports. We think that these decisions are best left to the RTO.

Should this reporting requirement be limited to producing reports only when a specific problem is encountered? Or should RTOs be required to make periodic reports that assess the state of competition and transmission access even in the absence of specific problems? We note that the California and New England ISOs have committed to producing annual public reports. Arguably such reports give market participants and others a regular opportunity to say whether they agree or disagree with the RTO assessment. Also, it is conceivable that such reports would be helpful to any market monitoring activities that this Commission and state commissions may wish to pursue in the future.

7. *Function 7: Planning and Expansion.* The RTO must be responsible for planning necessary transmission additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with the appropriate state authorities. (Proposed § 35.34(j)(7))

In carrying out Function 7, the RTO must satisfy each standard discussed below, or demonstrate that an alternative proposal is consistent with or superior to satisfying the standard.

a. The RTO planning and expansion process must encourage market-driven operating and investment actions for preventing and relieving congestion. (Proposed § 35.34(j)(7)(i))

RTOs should be designed to promote efficient usage and efficient expansion of their regional grids. The former requires efficient price signals, such as congestion pricing; the latter requires control over planning and expansion. Our specific proposal is that the RTO should have ultimate responsibility for both transmission planning and expansion within its region.[268] This

264 *See, e.g.*, David B. Raskin, ISOs: The New Antitrust Regulators? The Electricity Journal (April 1998).

265 For example, the ancillary services markets in the summer of 1998 in California behaved at odds with what one would expect in an efficient market. The California ISO market surveillance committee produced an extensive evaluation of this problem which led to discussions of possible solutions.

266 *See, e.g.*, James Barker, Jr., Bernard Tenenbaum, and Fiona Wolfe, "Governance and Regulation of Power Pools and System Operators: An International Comparison," Energy Law Journal, Volume 18, 1997, at 308–309.

267 *Pacific Gas & Electric*, 77 FERC ¶ 61,265 (1996). *NEPOOL*, 85 FERC ¶ 61,379 (1998).

268 Investments in new transmission facilities might be needed for a variety of reasons such as interconnecting new generation or load, protecting

requirement is motivated by the fact that investments in new transmission facilities must be coordinated to ensure a least cost outcome that maintains or improves existing reliability levels. In the absence of a single entity with overall responsibility, there would be danger that transmission investments would work at cross-purposes and possibly even hurt reliability. We recognize that the RTO's implementation of this general requirement will require addressing many specific design issues.[269] Once again, we propose to give RTOs considerable flexibility in designing a planning and expansion process that works best for its region. We recognize that the specific features of this process must take account of and accommodate existing institutions and physical characteristics of the region.

Within these constraints, the Commission has a clear preference for market-driven operating and investment actions for preventing and relieving congestion.[270] However, we understand that the feasibility of obtaining market driven solutions requires satisfying other prerequisites. For example, transmission prices must accurately reflect existing patterns of congestion. Accurate congestion prices are the link between current usage and future expansion. Therefore, we place considerable emphasis on the need for RTOs to establish a system of congestion management that establishes clear rights for existing and new transmission facilities and price signals that reflect congestion. (*See* section III.F) Independent governance is also a necessary condition for efficient expansion. While accurate price signals can signal the need for expansion, such expansion may never be achieved if the RTO operates under a faulty governance system (*e.g.*, a governance system that allows market participants to block expansions that will hurt their commercial interests).

b. The RTO's planning and expansion process must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The RTO's planning and expansion process must be coordinated with programs of existing Regional Transmission Groups (RTGs) where necessary. (Proposed § 35.34(j)(7)(ii))

At present, certification and siting of new transmission facilities is almost always performed by a state agency, typically the public utilities commission, in the state in which the facility will be located.[271] While there have been discussions about the need for regional certification and siting since most new transmission lines are integral elements of a regional grid system, such proposals have met with little success.[272] With the growth of RTOs, this could conceivably change. The emergence of a single regional transmission organization on the industry side may encourage the development of regional organizations or agreements that deal with transmission siting and certification on the regulatory side. The Commission believes that this would be a positive development if it is a voluntary decision of the affected states and replaces existing state-by-state determinations that often lack a regional perspective. To facilitate any voluntary actions taken by our state colleagues, we will require that the RTO planning and coordination system must be able to accommodate the possible future emergence of a regional regulatory system.

The Commission recognizes that regional transmission planning in some areas is being performed to varying degrees by RTGs.[273] It would be inefficient for RTOs initially to replicate the efforts of RTGs. Therefore, we require that RTOs discuss their planning and expansion with existing RTGs. However, over time, we would expect that the RTG's planning process would become an RTO function and the need for such coordination would be reduced or eliminated.

c. If the Regional Transmission Organization is unable to satisfy this requirement when it commences operation, it must file a plan with the Commission with specified milestones that will ensure that it meets this requirement no later than three years after initial operation. (Proposed § 35.34(j)(7)(iii))

We recognize that establishing an efficient procedure for transmission planning and expansion may require coordination and agreements among multiple parties and regulatory jurisdictions, and that this may take some time to accomplish. Accordingly, we do not propose that an RTO be capable of performing this function on its first day of operation. We do expect, however, that RTO proposals contain at least a plan explaining how the RTO intends to work toward implementing this function. Such a plan should set forth milestones that will result in this function being performed within three years after initial operation. We seek comment on whether three years is an appropriate amount of time for implementation of this function.

E. Open Architecture

The Commission believes that RTOs hold great promise in accomplishing our goal of promoting competition in regional wholesale electricity markets. That is why we want to accelerate their development. We understand that there are many difficult organizational, technical, and policy issues that must be addressed in realizing proposals, and that markets are evolving quickly and possibly in ways that cannot be foreseen at the time of RTO organization. Further, the nature of the institutions supporting the markets may change over time as well.

For these reasons, the Commission will require that RTO design have the ability to evolve over time. The Commission is committed to a policy of "open architecture." Simply put, open architecture requires that there be no provision in any RTO proposal that precludes the RTO and its members from improving their organizations to meet market needs. The Commission will provide the regulatory flexibility to allow such evolution.

Under open architecture, an RTO should be able to evolve in several ways, as long as it continues to satisfy the minimum RTO characteristics and

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or enhancing system reliability, improving system operating efficiency and flexibility, reducing or eliminating congestion and minimizing the need for "must-run" contracts with one or more generators.

[269] Our experience with regional transmission groups suggests that the following issues, among others, will need to be addressed: Who establishes the planning criteria? Who sets the design criteria? Should they be uniform across the system or vary with location? Who can initiate studies for transmission investments? Who evaluates and publishes different options? Who recommends which projects should be built and how the costs and benefits of the project should be allocated?

[270] This is a topic that has been discussed widely within the industry. *See, e.g.*, the papers of Steven L. Walton, Indego Transmission Expansion Strategy, Steven Stoft, Five Things You Should Know About Grid Investment and Ray Coxe, New Paradigms for Siting Transmission in Competitive Electric Markets. These papers are available through the Harvard Electric Policy Group website http://ksgwww.harvard.edu/hepg.

[271] *See* Ileana Elsa Garcia, State Electric Facility Siting Practices, prepared for the Harvard Electric Policy Group (HEPG), April 10, 1997. Available through the HEPG website at http://ksgwww.harvard.edu/hepg.

[272] *See* NARUC, "Options for Jurisdiction over Transmission Facility Siting," a resource document for the NARUC Committee on Electricity, 1991 and Charles D. Gray, NARUC Assistant General Counsel, Memorandum, January 1995. Available through the HEPG/website at http://ksgwww.harvard.edu/hepg.

[273] The Commission has approved RTGs for the New England Power Pool, *et al.*, 83 FERC ¶ 61,045 (1998), Mid-Continent Area Power Pool, 76 FERC ¶ 61,261 (1996), Northwest Regional Transmission Association, 71 FERC ¶ 61,397 (1995), Western Regional Transmission Association, 71 FERC ¶ 651,158 (1995), and Southwest Regional Transmission Association, 69 FERC ¶ 61,100 (1994).

functions. For example, open architecture would allow basic changes in the organizational form of the RTO. An RTO that initially does not own any transmission facilities might acquire ownership of some or all of those facilities. The RTO's enabling agreements should at best anticipate and facilitate such a change, but at minimum should not prevent it or make it more difficult than necessary.

Market trading patterns, technological change, and changes in corporate strategies will make changes in RTO membership inevitable and desirable. Accommodating change will require flexibility and adaptability in the RTO organization and open architecture will permit this.

Market support and operations is another RTO dimension that could benefit from open architecture. For example, an RTO may not initially operate a PX to support a regional spot market, but if RTO members later find that a PX would help the region, the RTO could propose to add the PX function as well as a PX market monitoring function. It is important that the basic RTO agreement not close off such development. Our proposed open architecture policy will ensure that such future development is not foreclosed.

The Commission is interested in receiving comments regarding an open architecture policy to ensure that initial RTOs can develop. What flexibility needs to be built into RTO contracts? What regulatory flexibility is needed from the Commission as part of an open architecture policy? In which areas of RTO organization or operations is it especially important for the Commission to expect improvement?

F. Ratemaking for Transmission Facilities Under RTO Control

The Commission expects RTOs to reform transmission pricing, and in return we propose to allow RTOs greater flexibility in designing pricing proposals. In 1994, the Commission issued its Transmission Pricing Policy Statement encouraging transmission pricing reform and setting out standards to be used to evaluate innovative transmission pricing proposals.[274] In the Transmission Pricing Policy Statement the Commission allowed "substantial flexibility" to be given to RTGs in justifying non-conforming proposals. The Commission allowed this because RTGs represent the combined interests of transmission owners, users and state authorities and because pricing proposals for treating loop flow problems work better if all utilities in the region use the same method.

In this section, we discuss a number of areas in which we expect RTOs to provide innovative pricing and in which the Commission may be expected to allow flexibility. We seek comments on the issues discussed and other RTO pricing issues.

1. Single Transmission Access Rate for Capital Cost Recovery

One issue in ISO proposals that have come before the Commission is the recovery of transmission capital costs through a single access rate. Under such a rate, the capital costs of all RTO members would be averaged, resulting in a rate that is higher than the individual system rate for relatively low-cost transmission systems and lower than the rate for high-cost transmission systems. This can cause two kinds of "cost-shifting" concerns: high-cost transmission providers are concerned about cost recovery, and customers of the low-cost providers are concerned about increased rates.

Transmission cost shifting has been an issue in every ISO the Commission has approved to date, and we have allowed a flexible approach to resolving the issue. In each of those cases, we have allowed a transition period of between five and ten years during which access fees are based on some form of "license plate" pricing: access fees are paid by load serving entities based on the fixed transmission costs of the local utility.[275]

We propose to continue our flexibility in allowing the recovery of current sunk transmission costs as transition mechanisms to single rates if proposed by RTOs, including the license plate approach as well as others. We request comment regarding whether the license plate approach to fixed cost recovery is an appropriate long-term measure.

2. Congestion Pricing

As discussed in prior sections, managing regional congestion is one of the problems that an RTO can help solve. We believe that efficient congestion management requires a greater reliance on market mechanisms[276] and this can be effectively accomplished with price signals. We propose to allow RTOs considerable flexibility in experimenting with different market approaches to managing congestion through pricing.[277] Proposals should, however, ensure that the generators that are dispatched in the presence of transmission constraints must be those that can serve system loads at least cost, and limited transmission capacity should be used by market participants that value that use most highly.[278]

The Commission intends to be flexible in reviewing pricing innovations, and we ask for comments as to what specific requirements, if any, may best suit our RTO goals.

3. Performance Based Rate Regulation

Once RTOs are formed, the Commission is interested in finding ways to ensure their satisfactory performance. One way to induce good grid operation by an RTO is through performance-based regulation, or PBR. PBR may consist of price/revenue caps, price incentives, or performance standards.[279] Performance-based regulation identifies factors of good performance such as efficient congestion management, lowering operator costs, and meeting reliability targets. Great care must be taken in selecting the performance factors. RTOs should have a reasonable chance of meeting or exceeding the performance targets, but the targets must not be too easy to meet. We would reward only performance that is truly superior to that which individual transmission owners could achieve outside an RTO.

The Commission seeks comments on applying PBR to RTOs. Should PBR be voluntary or applied to all RTOs? What degree of regulatory scrutiny would a PBR regime require? In addition, the Commission seeks comment on the specifics of how PBR would be applied

[274] The Policy Statement sets out five principles that transmission pricing proposals should conform to: meet the traditional revenue requirement; reflect comparability (open access tariff); promote economic efficiency; promote fairness; and be practical. The Policy Statement requires non-conforming proposals to satisfy additional factors: promote competitive markets and produce greater overall consumer benefits. Overall consumer benefits are measured principally by greater access and customer choice, projected price decreases to power customers, and service flexibility and products to meet customer needs.

[275] *See, e.g.*, Order Directing Amendments to Proposals to Restructure the Pennsylvania-New Jersey-Maryland Interconnection and Providing Guidance, 77 FERC ¶ 61,148 at 61,577 (addressing concerns about cost-shifting between high- and low-cost transmission providers).

[276] *See NERC*, 85 FERC at 62,364.

[277] This is consistent with our *Transmission Pricing Policy Statement's* allowance of substantial flexibility to pricing proposals from RTGs because RTGs are comprised of broad membership to facilitate transmission access, develop a comprehensive regional plan for transmission expansion, share transmission information and provide for dispute resolution. 64 FERC 61,138 (1993). RTOs possess these same characteristics.

[278] *Transmission Pricing Policy Statement*, FERC Stats. & Regs. at 31,140–44.

[279] *See* Incentive Ratemaking for Interstate Natural Gas Pipelines, Oil Pipelines, and Electric Utilities, Policy Statement on Incentive Regulation, 61 FERC ¶ 61,168 at 61,590–92 (1992), and L. Brown, Michael Einhorn, and Ingo Vogelsang, Incentive Regulation: A Research Report (1989).

effectively to an RTO. For productivity incentives, what productivity objectives should be adopted and how should productivity be measured? How would a revenue cap or a price cap be set? What intermediate adjustments to the cap should be allowed? How often should base costs be examined?

4. Consideration of Incentive Pricing Proposals

RTOs would bring extensive benefits to North American electricity markets and would further the objectives of sections 202(a), 205 and 206 of the FPA. We would be willing to consider, on a case by case basis, allowing the transmission owners that bring about those benefits to share in them through incentive pricing for public utility transmission owners that turn over control of their transmission facilities to an RTO.[280] RTOs would be expected to propose and justify specific proposals on a case-by-case basis.

One potential treatment that could be considered is allowing transmission owners that participate in RTOs to receive a higher return on equity (ROE) on transmission plant than under current policy because a transmission owner participating in an RTO puts its grid to a higher valued use than one operating individually. This relates the incentive to the benefit produced by the RTO. The simplest way to create a higher ROE is to share the benefits of an RTO between transmission owners and customers. Alternatively, a higher ROE could be implemented by either allowing an ROE at the high end of the zone of reasonable returns for RTO participants and an ROE in the current range for non-participants. Is it appropriate to allow a higher ROE as a means of sharing the benefits created by RTOs or should higher ROEs be limited only to increases in risk? Is the risk of transmission capital recovery increased or decreased by transferring transmission facilities to an RTO from a vertically integrated firm?

With improved grid operation and investment in new facilities to relieve constraints, RTOs may lower grid operating costs. Another incentive that could be considered would be to keep transmission rates at current levels and allow participating RTO transmission owners to keep the benefits from cost savings over time or to lower transmission rates partly while owners keep part of the benefits. Would such treatment encourage better performance?

The Commission could also consider flexibility in cost recovery for RTO participation. The capital cost of transmission plant is normally recovered over a relatively long time period. RTO participants could be allowed accelerated recovery for the costs of transmission expansion. Similarly, the recovery of capital start-up costs of RTO participation could be accelerated as well. Is it appropriate to allow such accelerated recovery as an incentive to transfer transmission facilities to an RTO or should capital recovery periods continue to be based on the useful life of transmission facilities? Is industry restructuring and the potential introduction of distributed generation technology likely to affect the risk associated with transmission investment recovery periods?

The Commission may also be willing to consider non-traditional methods for valuing transmission assets that are under the control of a RTO. The Commission's traditional ratemaking policy values assets at original cost, less depreciation. One alternative may be for rate base to reflect a higher valuation through some measure of replacement cost. Where an RTO or other independent owner purchases transmission assets and pay a price that reflects such an enhanced valuation of assets, the Commission may want to consider allowing the RTO to include in its rates an acquisition premium that reflects the enhanced value.

The Commission might also consider flexibility in allowing levelized or non-levelized rate methods. Both methods can produce reasonable results in particular circumstances, especially when one method is used consistently throughout the life of a utility's facilities. The Commission has, however, been reluctant to allow switching from a non-levelized to a levelized rate design during the life of a facility. The Commission's current policy is that a utility must prove that switching methods is reasonable in light of its past recovery of capital.[281] The Commission could consider granting some latitude for RTO pricing proposals for levelized rate cost recovery.

The Commission seeks comments on whether to entertain case-by-case proposals of rate incentive treatments for RTO participants. Will transmission owners respond to incentives, and will incentives be sufficient to achieve our objective of RTO formation? Which incentives are most likely to be successful in so doing? Are there specific forms of incentive pricing that are inappropriate and problematic? Are safeguards needed if the Commission decides to allow incentive treatments? In justifying a proposed rate treatment, should an RTO be required to demonstrate that its benefits are likely to outweigh the pecuniary "costs" of the proposal? Would certain incentive pricing encourage RTOs to favor capital-based resource decisions (at the expense of more efficient alternatives) or to favor transmission solutions over alternative ways of relieving particular transmission constraints? We also seek comment on whether and how public power transmission owners that participate in RTOs could benefit from flexible ratemaking and incentive pricing treatments.

Finally, our willingness to consider incentive pricing proposals is conditioned on an RTO meeting all of the proposed minimum characteristics and functions. Allowing any incentive pricing to RTO participants is based on a sharing of the extensive benefits that an RTO brings to electricity markets. Only an RTO that meets the minimum characteristics and functions can produce such extensive benefits, and it would be inappropriate for the Commission to consider incentive pricing to members of an RTO that falls short. We would, however, be open to considering other innovative transmission rate treatments, such as providing service at non-pancaked rates and regional congestion management proposals, for an organization that does not meet all of the minimum RTO characteristics and functions.

G. Public Power Participation in RTOs

The Commission's objective of encouraging all transmission owning entities in the Nation to place their transmission facilities under the control of an RTO includes transmission owned or controlled by public power entities [*e.g.*, municipals, cooperatives, Federal Power Marketing Agencies (PMAs), Tennessee Valley Authority (TVA), and other state and local entities]. We are aware that some public power entities have filed open access tariffs with the Commission and others are participating in ISOs and other regional institutions. We also are aware, however, that many public power entities may face several difficult issues regarding RTO participation. The Commission is concerned about any obstacle to public power participation in the formation and successful operation of any form of RTO. Accordingly, we request comments that identify issues that

[280] As discussed above in section III–B, there are also a number of non-pricing regulatory benefits that could be offered to RTO members, such as deference in dispute resolution, reduced or eliminated codes of conduct, and streamlined filing and approval procedures.

[281] *See* Consumers Energy Company, 85 FERC ¶ 61,100, at 61,366–367, 1998); Kentucky Utilities Company, 85 FERC ¶ 61,274, at 62,103–105 (1998).

public power entities and others face regarding RTO participation and that suggest ways the Commission might facilitate their resolution. We expect public power entities to fully participate in the proposed collaborative process for forming RTOs after our Final Rule is issued, as discussed in section III–I below.

One issue is the Internal Revenue Service (IRS) Code "private use" restrictions on the transmission facilities of public power entities financed by tax-exempt bonds. IRS temporary regulations may allow facilities financed by outstanding tax-exempt bonds to be used to wheel power in accordance with Order No. 888, but they may not allow the issuance of additional tax-exempt bonds for expanded transmission or permit transfer of operational control of existing transmission facilities financed by tax-exempt bonds to a for-profit transco.[282] In addition, there is uncertainty regarding what may happen after the temporary regulations expire on January 22, 2001.

We solicit comments on the extent to which IRS Code restrictions may limit the transfer of operational control or other forms of control, or ownership, of public power transmission facilities to a for-profit transco. What impact would IRS Code restrictions have on public power participation in other forms of an RTO? While IRS Code restrictions might prevent issue of additional tax-exempt bonds for transmission expansions made in accordance with RTO participation, are non-tax exempt forms of financing a viable option for public power participation in selected transmission additions?

In addition to private use restrictions, are there other restrictions on public power institutions that may limit their participation in RTOs? For example, to what extent would state or local charter limitations, prohibitions on participating in stock-owning entities, or the current policies of various local regulatory entities affect or impede full public power participation in RTOs? Are there some forms of associate membership or participation in RTOs, or other special accommodations, that the Commission should consider to make it more feasible for public power entities to overcome obstacles to participation in RTOs?

The Commission seeks comment on legal restrictions or other considerations regarding the PMAs that prevent their participation in RTOs. For example, Bonneville Power Administration and other entities in the Pacific Northwest may face unique circumstances that may affect RTO formation in that area. These include the design of the power and transmission system for the production of hydroelectric energy involving the 1961 Columbia River Treaty, the Bonneville Project Act, the Federal Columbia River Transmission System Act, the Pacific Northwest Electric Power Planning and Conservation Act of 1980, and the Northwest Preference Act. There may also be obstacles to TVA participation in an RTO. How can the Commission help overcome any such limiting factors to full RTO formation?

H. Other Issues

The Commission seeks comment on a number of other issues regarding RTO participation. These issues are presented in this section.

1. Pre-existing Transmission Contracts

What is the appropriate treatment of existing transmission agreements when an RTO is formed? In Order Nos. 888 and 888–A, we specifically chose not to abrogate existing requirements and transmission contracts when the utility filed an open access tariff.[283] However, an RTO represents an entirely different context. We must balance the need for a uniform approach for transmission pricing and the elimination of pancaked rates—one of the principal benefits of an RTO—with the need to recognize the equities inherent in existing transmission contracts. The potential financial impact of giving up an advantageous transmission arrangement may act as a disincentive to joining an RTO.

In the ISO filings that we have acted on to date, we have evaluated various "transition plans" regarding existing contracts on a case-by-case basis.[284] At this juncture, we do not intend to resolve this issue generically but instead propose to confine our policy to addressing this issue on an RTO-by-RTO basis. We solicit comments on this approach. How critical is this concern to transmission owners' and others' decisions on whether to support RTO formation? Is the financial impact of giving up an advantageous transmission arrangement significant enough to act as a disincentive to RTO membership?

2. Treatment of Existing Regional Transmission Entities

We propose to adopt in the Final Rule certain characteristics and functions to be required of RTOs. It could turn out that the ISOs and any other regional transmission entities that conform to the Commission's ISO principles that we have approved to date do not meet all of these characteristics and functions. It is our expectation that, to the extent this is the case, the existing regional transmission entities will over time evolve to be consistent with the characteristics and functions adopted in the Final Rule. The Commission recognizes that a number of operational, financial and political issues will need to be addressed in the course of such an evolution and that it cannot be accomplished overnight. We also respect the investment of time and other resources made in the existing transmission entities, and understand the importance of avoiding change during the critical implementation period these institutions are now undergoing. Given these considerations, and our policy of regional flexibility, the proposed rule does not require major changes to the existing transmission entities. However, our objective is to encourage all of the Nation's transmission grid to be under the control of RTOs that have the minimum characteristics and functions adopted in the Final Rule. We therefore propose to require each public utility that is a member of an existing regional transmission entity that has been approved by the Commission as in conformance with the eleven ISO principles set forth in Order No. 888 to make a filing no later than January 15, 2001 that explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions for an RTO, or proposes to modify the existing institution to become an RTO. Alternatively, the public utility may file an explanation of efforts, obstacles and plans with respect to conforming to these characteristics and functions.[285] The Commission is also concerned about impediments to transactions between existing transmission entities, as well as any future RTOs. We therefore encourage existing transmission entities to consider ways to reduce any impediments to transactions among them and direct

[282] *See* Uncrossing the Wires, Transmission in a Restructured Market, a report by The Large Public Power Council, December 1998, at 10.

[283] *See* Order No. 888 at 31,664–65; Order No. 888–A at 30,181, 30,199; clarified, 76 FERC at 61,027; Order No. 888–B, 81 FERC at 62,072, 62, 090, 62,100.

[284] *See PJM,* 81 FERC at 62,280–81; *Midwest ISO,* 84 FERC at 62,169–70 and *order on reh'g,* 85 FERC at 62,418–20 (1998); *Pacific Gas & Electric,* 777 FERC at 61,821, 81 FERC at 61,470–71; *NEPOOL,* 83 FERC at 61,241–42; Central Hudson Gas & Electric Co. *et al.,* 86 FERC at 61,218–19.

[285] Of course, there is nothing to prevent an existing transmission entity from making an RTO filing prior to this date if it so chooses.

them to provide the Commission with a progress report by January 15, 2001.

The Commission seeks comment on this issue.

3. Participation by Canadian and Mexican Entities

Canadian and Mexican involvement in RTO formation would be beneficial to both, as well as to the United States. In certain areas, "natural" electricity trading regions already cross national borders. Expansion of electricity trade in the North American bulk power market requires that regional institutions include all market participants so that they may enjoy direct access to market information and the benefits of non-pancaked transmission rates. In addition, any reliability standards implemented by RTOs must be acceptable to the affected nations and consider all resources to avoid wasteful duplication of grid facilities.[286]

We encourage electric utilities in Canada and Mexico, and their regulatory authorities, to participate in the discussions of the rulemaking. Perhaps what may be thought of as a "dotted line" RTO boundary could be used at international borders to indicate an unwillingness to artificially limit an RTO's scope while recognizing jurisdictional limits. The Commission emphasizes that Canadian and Mexican authorities would be responsible for approving prices and other terms and conditions of transmission service provided over any RTO transmission facilities located in their countries. We invite the comments of Canadian and Mexican authorities on these and other issues.

4. Providing Service to Transmission-owning Utilities that do not Participate in an RTO

The transmission owners that turn control of transmission facilities over to an RTO will help bring significant operational and commercial benefits to a region. To what extent should transmission owners who do not participate in their region's RTO share in those benefits? Would it be appropriate to allow RTO members to provide transmission service at individual system rates to non-participating transmission owners located in the RTO region, thereby denying non-participants the benefits of non-pancaked transmission rates? The Commission seeks comment on the treatment by an RTO of non-participating transmission owners in the RTO region.

5. RTO Filing Requirements

Any transfer of control of jurisdictional transmission facilities owned, operated, or controlled by public utilities required by RTO formation must be approved by the Commission pursuant to its Section 203 authority under the FPA. The RTO transmission rates, terms, and conditions of service must also be approved pursuant to Section 205 of the FPA. We request comments on whether the Commission should provide for expedited or streamlined processing procedures for Section 203 transfers of jurisdictional facilities to RTOs that meet the characteristics and functions of the Final Rule, and for the related Section 205 transmission rates, terms, and conditions. We also welcome specific suggestions regarding how we can further expedite or streamline our procedures.

6. Power Exchanges (PXs)

Another important issue is the relationship between RTOs and power exchanges. Of the five ISOs approved to date, only the Midwest ISO chose not to include a power exchange in the design submitted to us.[287] However, after the Commission approved this proposal, several ISO participants joined with other Midwestern power entities in issuing a public request for proposals that would create an independent power exchange that would operate in conjunction with the ISO.[288] This recent Midwest initiative appears to have been motivated, at least in part, by the large price spikes that were experienced last summer. Our staff's report concluded that one of probable causes of the price spikes was the lack of price transparency and that "centralized trading institutions such as power exchanges could have provided better price signals in the market and helped to reduce price volatility."[289]

Regions may want to consider establishing a PX that is operated by an RTO. However, some oppose RTO-operated PXs, contending that the two principal functions of PXs, market making and price discovery, are not natural monopoly functions.[290] They also contend that power exchanges force market participants to buy and sell electricity using standardized contracts that may not meet their particular needs. They argue that the full benefits of electricity competition can be achieved only if there is competition for the market as well as in the market. Finally, they assert that if power exchanges are introduced, an RTO should be specifically prohibited from operating the exchange because this would compromise the RTO's independence in fulfilling its principal responsibilities as a transmission service provider and system operator.[291]

In contrast, those who recommend that an RTO should operate a PX contend that the two functions of short-term forward or spot market operations and system operations are difficult to separate.[292] It is their view that there will be significant inefficiencies unless the two functions are performed simultaneously by a single entity.[293] In addition, they contend that there is no inherent conflict between the RTO as a transmission service provider and a spot market operator as long as the RTO has no commercial interest in whether prices are high or low in the markets that it operates.

We leave it to each region to decide whether there is a need for a PX and whether the RTO should operate the PX. The Commission will accept an RTO

[286] Historically, Canada and Mexico have participated in North American utility organizations such as NERC and Western Systems Coordinating Council (WSCC). Maintaining Reliability in a Competitive U.S. Electricity Industry, Final Report of the Task Force on Electric System Reliability, Secretary of Energy Advisory Board, DOE, September 29, 1998 at 9, 58.

[287] In California, PXs are operated by separate organizations that coordinate with the ISO.

[288] *See* Joint Committee for the Development of a Midwest Independent Power Exchange, "Solicitation of Interest-Creation of an Independent Power Exchange for the U.S. Midwest," February 5, 1999.

[289] Staff Report to the Federal Energy Regulatory Commission on the Causes of Wholesale Electric Pricing Abnormalities in the Midwest During June 1998, September 1998, at 4–4. Centralized power exchanges appear to have other benefits. Since most power exchanges establish credit and security standards as a condition for participation and reserve funds to cover defaults, they create a type of insurance by spreading counterparty risks among all participants and thereby reducing the likelihood of cascading transaction defaults such as those that occurred in the Midwest. In addition, it is generally accepted that an organized and transparent spot market is a prerequisite for a viable futures market which would allow market participants to hedge the risk of future price fluctuations. Finally, we note that during our recent consultations with state commissions, several state commissioners informed us that organized and open spot markets were critical to the success of their efforts to introduce retail competition in their respective states.

[290] *See, e.g.*, comments of Enron in PL98–5, Washington, D.C., transcript at 211.

[291] *See, e.g.*, comments of Automated Power Exchange, Inc., in PL98–5 at 3.

[292] *See* Professor William W. Hogan, "Enabling The Power Of Markets," presentation at the EEI Chief Executive Conference, Scottsdale, Arizona, January 7, 1999, at 8. A copy of this presentation is available on Professor Hogan's website (www.ksg.harvard.edu/people.whogan).

[293] *See* Dr. Larry Ruff, "Competition in Electricity: Where Do We Go From Here?", lecture at the Institute of Economic Affairs, London Business School, October 13, 1998. Available through the website of the Harvard Electric Policy Group (http://ksgwww.harvard.edu/hepg/FPpapers.html).

proposal that includes a PX in its design as long as its operation of the PX does not compromise its independence as a transmission service provider. We request comments on the following questions. Given that a power exchange is useful, should it be part of an RTO or otherwise associated with an RTO? If an area has more than one PX, should the PXs have equal standing before the RTO? Is an organized PX necessary for successful retail competition? If an RTO operates congestion markets and balancing markets, are there efficiencies to be gained by allowing or encouraging the RTO to operate day ahead or hour ahead energy markets? Is it feasible for an RTO to operate a spot energy market without compromising its ability to provide non-discriminatory transmission service to all market participants? If a PX is operated by a non-RTO entity, is there a need to require certain specified forms of coordination between the two organizations?

I. Implementation of the Rule

The Commission seeks to support timely RTO formation in every region of the country. To that end, the Commission envisions regional collaborations soon after issuance of the Final Rule, building on progress made to that date. Further, pursuant to our expectation that utilities and other participants in the electric industry form RTOs, the Commission proposes to require that certain filings be made by October 15, 2000 concerning RTO formation. The collaborative process and filing requirements are discussed in more detail below.

1. Collaborative Process

During our consultations with the state commissions, many said that Commission leadership is needed to facilitate RTO formation and that only we could facilitate broad regional participation. To facilitate RTO formation in all regions of the Nation, the Commission proposes a collaborative process under section 202(a) to take place in the spring of 2000, after adoption of a Final Rule. The Commission expects public utilities and non-public utilities, in coordination with appropriate state officials, and affected interest groups in a region to fully participate in working to develop an RTO.

To assist in structuring the regional collaborations and to further inform the Commission on activities in each region, we propose that regional workshops be held throughout the Nation after the Final Rule is issued. The goal of these workshops would be to share information about the status of RTOs or RTO proposals in the region, to identify any impediments to RTO formation in the area, to explore what process could most expeditiously advance agreements on RTO formation, and to determine what role, if any, Commission staff should play in advancing discussions in the region. These regional workshops would be convened by Commission staff in cooperation with the affected state officials. The Commission would specifically invite each entity in the Nation that owns or operates transmission facilities, and representatives from Canada and Mexico as appropriate, to the public workshops. The Commission proposes to make staff resources, including settlement judges, available through our Dispute Resolution Service to assist in designing and possibly facilitating regional collaborations following the workshops. Commission technical staff will be made available for participation in the regional collaborations.

Would regional workshops advance RTO formation? Under whose auspices should regional workshops be held? Would it be beneficial to have the Commission's Dispute Resolution Service staff facilitate discussions regarding RTO formation? Should the Commission staff convene the regional workshops or should Commission staff be made available to attend meetings convened by others? If the Commission staff convenes workshops, in how many cities should meetings be convened and how should the cities be chosen? Would the three U.S. interconnections be appropriate starting points? Would participation of Commission staff aid or stifle negotiations on RTO development?

2. Filing Requirement

The Commission is hopeful that the direction provided by this rulemaking, the regional collaborations described above, and the possibility of incentive rate treatments will lead to the prompt development of RTO proposals. Thus, we propose that all public utilities that own, operate or control interstate transmission facilities (except those already participating in a regional transmission entity in conformance with our eleven ISO principles) must file with the Commission by October 15, 2000, either (1) a proposal to participate in an RTO that will be operational no later than December 15, 2001, or (2) an alternative filing describing efforts to participate in an RTO, obstacles to RTO participation, and any plans and timetables for future efforts (see proposed § 35.34(c)).[294] To the extent possible, RTO proposals should include the transmission facilities of public power and other non-public utility entities.

The number and type of filings necessary to effectuate an RTO proposal necessarily will vary depending upon the type of RTO being proposed and the circumstances of each individual public utility participant. At a minimum, an RTO proposal must include a basic agreement filed under section 205 of the FPA setting out the rules, practices and procedures under which an RTO will be governed and operated, and requests by the public utility members of the RTO for approval under section 203 of the FPA to transfer control of their jurisdictional transmission facilities. However, depending upon the circumstances, there may need to be additional section 205 or 206 amendments to existing public utility contracts or rate schedules in order to effectuate an RTO proposal.

For those public utilities that file an RTO proposal on or before October 15, 2000, we will permit them to file a petition for declaratory order asking whether a proposed transmission entity would qualify as an RTO, with a description of the organizational and operational structure and the intended participants of the institution, an explanation of how the institution would satisfy each of the RTO minimum characteristics and functions, and a commitment to submit necessary section 203, 205 and 206 filing promptly after receiving the Commission's determination on the declaratory order petition (see proposed § 35.34(d)(3)). This declaratory order petition option thus is to be used only in conjunction with the filing of a proposal for an RTO that is to begin operation no later than December 15, 2001.

If a public utility is not able to file an RTO proposal on or before October 15, 2000, it must alternatively file by that date a description of any efforts made by the public utility to participate in an RTO, the reasons it has not participated in an RTO, including identifying specific obstacles to RTO participation, and any plans and timetables the public

[294] A proposal to form a transmission institution that does not meet all of the minimum RTO characteristics and functions will not be approved as an RTO. This does not necessarily mean that the proposal will not otherwise be approved as consistent with the FPA. However, the proposal will not qualify as an RTO. For transmission organizations that do not meet all of the minimum RTO characteristics and functions, however, we would still be open to considering, and indeed encourage, regional filings for providing service at non-pancaked rates and regional congestion management proposals.

utility has for further work toward RTO participation (see proposed § 35.34(f)). If a public utility makes such an alternative filing, the Commission at that time will determine what steps, if any, need to be taken.

The above requirements, however, do not apply to a public utility that is a member of an existing transmission entity that the Commission has found to be in conformance with the Order No. 888 ISO principles. Rather, each such public utility must make a filing no later than January 15, 2001 that (1) explains the extent to which the transmission entity in which it participates meets the minimum characteristics and functions for an RTO, (2) proposes to modify the existing institution to become an RTO, or (3) explains efforts, obstacles and plans with respect to conforming to these characteristics and functions (see proposed § 35.34(g)).[295]

The Commission does not propose to mandate RTO participation by rule, and instead proposes to induce voluntary participation through a combination of guidance on the minimum characteristics and functions of an RTO, possible rate incentives, a collaborative process for structuring regional dialogues, and filing requirements. The Commission seeks comment on whether the filing requirements discussed above are inconsistent with or otherwise would inhibit voluntary participation in RTOs. The Commission also seeks comment on whether it needs to generically mandate RTO participation by all public utilities to remedy undue discrimination under sections 205 and 206 of the FPA. We also seek comment on whether a performance based system could be designed to realign economic interests to remove the motive for discrimination.

In considering what actions might be appropriate if a utility fails to voluntarily join an RTO, the Commission seeks comment on whether market-based rates for generation services could continue to be justified for a public utility that does not participate in an RTO, whether a merger involving a public utility that is not a member of an RTO would be consistent with the public interest, whether non-participants that own transmission facilities should be allowed to use the non-pancaked transmission rates of the RTO participants in that region, whether transmission services provided by a transmitting utility need to be under RTO control to satisfy the discrimination standards of sections 211 and 212 of the FPA, and whether a public utility's lack of participation would otherwise be in violation of the FPA. Does the possibility of any of these remedial actions for RTO non-participation undermine or otherwise inhibit voluntary participation in RTOs? How should the Commission consider the efficiency, reliability, and discrimination implications of RTO non-participation? How should the Commission consider non-participation by utilities that constitute "holes" in an RTO region?

The Commission anticipates that public utilities will file proposals for ISOs, transcos, or other types of regional transmission institutions prior to the effective date of the Final Rule. We clarify that the Commission will continue to apply to these proposals the ISO principles contained in Order No. 888 and the case precedent established for ISOs. However, a public utility that files such a proposal prior to the effective date of the Final Rule would still be subject to the October 15, 2000 or January 15, 2001 filing requirement, as appropriate, in the Final Rule.

[295] Of course, there is nothing to prevent an existing entity from making an RTO filing prior to this date if it so chooses.

IV. Environmental Statement

In furtherance of the National Environmental Policy Act of 1969, the staff of the Federal Energy Regulatory Commission will prepare an environmental assessment (EA) that will consider the environmental impacts of the proposed rule. A notice of intent to prepare the EA, request comments on the scope of the EA, and notice of a public scoping meeting is published elsewhere in this issue of the **Federal Register**.

V. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA), 5 U.S.C. §§ 601–612, requires rulemakings to contain either a description and analysis of the effect that the proposed rule will have on small entities or a certification that the rule will not have a significant economic impact on a substantial number of small entities. If this proposed rule goes into effect, it will establish minimum characteristics and functions for RTOs, none of which is likely to meet the SBA's definition of a small electric utility, i.e., one that disposes of 4,000,000 MWh per year or less. 13 C.F.R. § 121.201. Furthermore, the rule will not have the requisite impact upon transmission owners.

In *Mid-Tex Elec. Coop.* v. *FERC*, 773 F.2d 327 (D.C. Cir. 1985), the court found that Congress, in passing the RFA, intended agencies to limit their consideration "to small entities that would be directly regulated" by proposed rules. *Id.* at 342. The court further concluded that "the relevant 'economic impact' was the impact of compliance with the proposed rule on regulated small entities." *Id.* at 342.

The proposed rule will not regulate any small entities, nor will it impose upon them any significant costs of compliance. Small entities will be free to determine for themselves whether to participate in an RTO and whether any costs associated with joining an RTO will be adequately offset by attendant benefits. The only requirement the rule would impose upon a small entity would be the need to file a statement explaining its efforts to join an RTO, any barriers it encountered, and any future plans to seek to join an RTO. The Commission believes that the costs associated with preparing and filing such a statement will be minimal. Consequently, the Commission certifies that this proposed rule will not have a significant economic impact upon a substantial number of small entities.

VI. Public Reporting Burden and Information Collection Statement

The following collections of information contained in this proposed rule are being submitted to the Office of Management and Budget (OMB) for review under Section 3507(d) of the Paperwork Reduction Act of 1995. FERC identifies the information provided under Part 35 as FERC–516 and under Part 33 as FERC–519.

Comments are solicited on the Commission's need for this information, whether the information will have practical utility, the accuracy of the provided burden estimates, ways to enhance the quality, utility, and clarity of the information to be collected, and any suggested methods for minimizing respondents' burden, including the use of automated information techniques. The burden estimates for complying with this proposed rule are as follows:

Public Reporting Burden: Estimated Annual Burden:

Data collection	Number of respondents	Number of responses	Hours per response	Total annual hours
FERC–516	12	1	300	3,600
FERC–519	[1] 50	1	80	4,000
Totals				7,600

[1] Includes respondents who make application to form an RTO and the responses of utilities who choose not to participate.

Total Annual Hours for Collection (reporting+record keeping, (if appropriate))=7,600.

Information Collection Costs: The Commission seeks comments on the costs to comply with these requirements. It has projected the average annualized cost for all respondents to be:

Annualized Capital/Startup Costs—

Annualized Costs (Operations & Maintenance) – $401,518 (7,600 hours ÷ 2080 hours per year × $109,889 =$401,518). The cost per respondent is equal to $8,030 (participants and non-participants).

The OMB regulations require OMB to approve certain information collection requirements imposed by agency rule. *(Footnote 5 CFR 1320.11)*

Accordingly, pursuant to OMB regulations, the Commission is providing notice of its proposed information collections to OMB.

Title: FERC–516, Electric Rate Schedule Filings; FERC–519 Application for Sale, Lease, or Other Disposition, Merger or Consolidation of Facilities or for the Purchase or Acquisition of Securities of a Public Utility.

Action: Proposed Data Collections.

OMB Control No.: 1902–0096 and 1902–0082.

The applicant shall not be penalized for failure to respond to this collection of information unless the collection of information displays a valid OMB control number.

Respondents: Business or other for profit, including small businesses.

Frequency of Responses: One time.

Necessity of Information: The proposed rule revises the requirements contained in 18 CFR part 35. The Commission is seeking to establish RTOs nationwide by December 2001. In particular, the Commission will establish in this proposed rule characteristics and functions which applicants must meet to become Commission approved RTOs. The Commission will engage in a collaborative process with state officials and others to facilitate RTO development. The proposed rule will require that each public utility that owns, operates or controls transmission facilities participate in one-time filings proposing an RTO or make a filing explaining why they are not participating in an RTO proposal.

Internal Review: The Commission has assured itself, by means of internal review, that there is specific, objective support for the burden estimates associated with the information requirements. The Commission's Offices of Electric Power Regulation and Economic Policy will use the data included in filings under Section 203 and 205 of the Federal Power Act to evaluate efforts for the interconnection and coordination of the U.S. electric transmission system and to ensure the orderly formation of RTOs as well as for general industry oversight. These information requirements conform to the Commission's plan for efficient information collection, communication, and management within the electric power industry.

Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426 [Attention: Michael Miller, Capital Planning and Policy Group, Phone: (202) 208–1415, fax: (202) 208–2425, E-mail: mike.miller@ferc.fed.us].

For submitting comments concerning the collection of information(s) and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Management and Budget, Office of Information and Regulatory Affairs, Washington, DC 20503, [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395–3087, fax: (202) 395–7285].

VII. Public Comment Procedures

The Commission invites interested persons to submit written comments on the matters and issues proposed in this notice to be adopted, including any related matters or alternative proposals that commenters may wish to discuss. Initial comments should not exceed 100 double-spaced pages and should include an executive summary. The original and 14 copies of such comments must be received by the Commission before 5:00 p.m. on August 16, 1999.

The Commission will also permit interested persons to submit reply comments in response to the initial comments filed in this proceeding. Reply comments should not exceed 50 double-spaced pages and should include an executive summary. The original and 14 copies of the reply comments must be received by the Commission before 5:00 p.m. on September 15, 1999.

Comments should be submitted to the Office of the Secretary, Federal Energy Regulatory Commission, 888 First Street, N.E., Washington D.C. 20426 and should refer to Docket No. RM99–2–000.

In addition to filing paper copies, the Commission encourages the filing of comments either on computer diskette or via Internet E-Mail. Comments may be filed in the following formats: WordPerfect 8.0 or lower version, MS Word Office 97 or lower version, or ASCII format.

For diskette filing, include the following information on the diskette label: Docket No. RM99–2–000; the name of the filing entity; the software and version used to create the file; and the name and telephone number of a contact person.

For Internet E-Mail submittal, comments should be submitted to "comment.rm@ferc.fed.us" in the following format. On the subject line, specify Docket No. RM99–2–000. In the body of the E-Mail message, include the name of the filing entity; the software and version used to create the file, and the name and telephone number of the contact person. Attach the comments to the E-Mail in one of the formats specified above. The Commission will send an automatic acknowledgment to the sender's E-Mail address upon receipt. Questions on electronic filing should be directed to Brooks Carter at 202–501–8145, E-Mail address brooks.carter@ferc.fed.us.

Commenters should take note that, until the Commission amends its rules and regulations, the paper copy of the filing remains the official copy of the document submitted. Therefore, any discrepancies between the paper filing and the electronic filing or the diskette will be resolved by reference to the paper filing.

All written comments will be placed in the Commission's public files and will be available for inspection in the Commission's Public Reference room at 888 First Street, N.E., Washington D.C. 20426, during regular business hours. Additionally, comments may be viewed, printed or downloaded remotely via the Internet through FERC's Homepage using the RIMS or CIPS link. RIMS contains all comments but only those comments submitted in electronic format are available on CIPS. User assistance is available at 202–208–2222, or by E-Mail to rimsmaster@ferc.fed.us.

List of Subjects in 18 CFR Part 35

Electric power rates, Electric utilities, Reporting and recordkeeping requirements.

By direction of the Commission.

David P. Boergers,

Secretary.

In consideration of the foregoing, the Commission proposes to amend Part 35, Chapter I, Title 18 of the *Code of Federal Regulations*, as set forth below.

PART 35—FILING OF RATE SCHEDULES

1. The authority citation for part 35 continues to read as follows:

Authority: 16 U.S.C. 791a-825r, 2601–2645; 31 U.S.C. 9701; 42 U.S.C. 7101–7352.

2. Part 35 is amended by adding a new Subpart F consisting of § 35.34 to read as follows:

Subpart F—Procedures and Requirements Regarding Regional Transmission Organizations

§ 35.34 Regional Transmission Organizations.

(a) *Purpose.* This section establishes required characteristics and functions for Regional Transmission Organizations for the purpose of promoting efficiency and reliability in the operation and planning of the electric transmission grid and ensuring nondiscrimination in the provision of electric transmission services. This section further directs each public utility that owns, operates, or controls facilities used for the transmission of electric energy in interstate commerce to make certain filings with respect to forming and participating in a Regional Transmission Organization.

(b) *Definitions.*

(1) *Regional Transmission Organization* means an entity that satisfies the minimum characteristics set forth in paragraph (i) of this section, performs the functions set forth in paragraph (j) of this section, and accommodates the open architecture conditions set forth in paragraph (k) of this section.

(2) *Market participant* means any entity that buys or sells electric energy in the Regional Transmission Organization's region or in any neighboring region that might be affected by the Regional Transmission Organization's actions, or any affiliate of such an entity.

(c) *General rule.* Except for those public utilities subject to the requirements of paragraph (g) of this section, every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of [effective date of the final regulation] must file with the Commission, no later than October 15, 2000, one of the following:

(1) A proposal to participate in a Regional Transmission Organization consisting of one of the types of submittals set forth in paragraph (d) of this section; or

(2) A submittal consistent with paragraph (f) of this section.

(d) *Proposal to participate in a Regional Transmission Organization.* For purposes of this section, a proposal to participate in a Regional Transmission Organization means:

(1) Necessary filings, made individually or jointly with other entities, pursuant to sections 203, 205 and/or 206 of the Federal Power Act (16 U.S.C. 824b, 824d, and 824c), as appropriate, to create a new Regional Transmission Organization;

(2) Necessary filings, made individually or jointly with other entities, pursuant to sections 203, 205 and/or 206 of the Federal Power Act, as appropriate, to join a Regional Transmission Organization approved by the Commission on or before the date of the filing; or

(3) A petition for declaratory order, filed individually or jointly with other entities, asking whether a proposed transmission entity would qualify as a Regional Transmission Organization and containing at least the following:

(i) A detailed description of the proposed transmission entity, including a description of the organizational and operational structure and the intended participants;

(ii) A discussion of how the transmission entity would satisfy each of the characteristics and functions of a Regional Transmission Organization specified in paragraphs (i), (j) and (k) of this section;

(iii) A detailed description of the section 205 rates that will be filed for the transmission entity; and

(iv) A commitment to make necessary filings pursuant to sections 203, 205 and/or 206 of the Federal Power Act, as appropriate, promptly after the Commission issues an order in response to the petition.

Note to paragraph (d): Under this paragraph (d), the Commission would consider a request for incentive rate treatment or another form of innovative transmission pricing, such as performance based rates. Such a filing must include a detailed explanation of how the proposed rate treatment would help achieve each of the minimum characteristics and functions and would result in benefits to consumers.

(e) *Transfer of operational control.* Any public utility's proposal to participate in a Regional Transmission Organization filed pursuant to paragraph (c)(1) of this section must propose that operational control of that public utility's transmission facilities will be transferred to the Regional Transmission Organization on a schedule that will allow the Regional Transmission Organization to commence operating the facilities no later than December 15, 2001.

Note to paragraph (e): The requirement in this paragraph (e) may be satisfied by proposing to transfer to the Regional Transmission Organization ownership of the facilities in addition to operational control.

(f) *Alternative filing.* The submittal referred to in paragraph (c)(2) of this section must contain a description of any efforts made by that public utility to participate in a Regional Transmission Organization; the reasons it has not, to date, participated in a Regional Transmission Organization, including identification of any existing obstacles to participation in a Regional Transmission Organization; and any plans the public utility has for further work toward participation in a Regional Transmission Organization.

(g) *Public utilities participating in approved transmission entities.* Every public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of [effective date of the final regulation], and that has filed with the Commission to transfer operational control of its facilities to a transmission entity that has been approved or conditionally approved by the Commission as being in conformance with the eleven ISO principles set forth in Order No. 888, FERC Stats. & Regs. ¶31,036 (Final Rule on Open Access and Stranded Costs) on or before [effective date of the final regulation], must, individually or jointly with other entities, file with the Commission, no later than January 15, 2001:

(1) A statement that it is participating in a transmission entity that has been so approved;

(2) A detailed explanation of the extent to which the transmission entity in which it participates has the characteristics and performs the functions of a Regional Transmission Organization specified in paragraphs (i) and (j) of this section and accommodates the open architecture conditions in paragraph (k) of this section; and

(3) To the extent the transmission entity in which the public utility participates does not meet all the requirements of a Regional Transmission Organization specified in paragraphs (i), (j), and (k) of this section, the public utility must file either a proposal to participate in a Regional Transmission Organization that meets such requirements in accordance with paragraph (d) of this section, a proposal to modify the existing transmission entity so that it conforms to the requirements of a Regional Transmission Organization, or a filing containing the information specified in paragraph (f) of this section addressing any efforts, obstacles, and plans with respect to conformance with those requirements.

(h) *Entities that become public utilities with transmission facilities.* An entity that is not a public utility that owns, operates or controls facilities used for the transmission of electric energy in interstate commerce as of [effective date of the final regulation], but later becomes such a public utility, must file a proposal to participate in a Regional Transmission Organization in accordance with paragraph (d) of this section, or an alternative filing in accordance with paragraph (f) of this section, by October 15, 2000 or 60 days prior to the date on which the public utility engages in any transmission of electric energy in interstate commerce, whichever comes later. If a proposal to participate in accordance with paragraph (d) of this section is filed, it must propose that operational control of the applicant's transmission system will be transferred to the Regional Transmission Organization within 6 months of filing the proposal.

(i) *Required characteristics for a Regional Transmission Organization.* A Regional Transmission Organization must satisfy the following characteristics when it commences operation:

(1) *Independence.* The Regional Transmission Organization must be independent of market participants.

(i) The Regional Transmission Organization, its employees, and any non-stakeholder directors must not have financial interests in any market participants.

(ii) A Regional Transmission Organization must have a decision making process that is independent of control by any market participant or class of participants.

(iii) The Regional Transmission Organization must have exclusive and independent authority to file changes to its transmission tariff with the Commission under Section 205 of the Federal Power Act.

(2) *Scope and regional configuration.* The Regional Transmission Organization must serve an appropriate region. The region must be of sufficient scope and configuration to permit the Regional Transmission Organization to effectively perform its required functions and to support efficient and non-discriminatory power markets.

(3) *Operational authority.* The Regional Transmission Organization must have operational responsibility for all transmission facilities under its control.

(i) The Regional Transmission Organization may choose to directly operate facilities (direct control), delegate certain tasks to other entities (functional control) or use a combination of the two approaches. If certain operational functions are delegated to, or shared with, entities other than the Regional Transmission Organization, the Regional Transmission Organization must ensure that this sharing of operational responsibility will not adversely affect reliability or provide some market participants with an unfair competitive advantage. Within two years after initial operation as a Regional Transmission Organization, the Regional Transmission Organization must prepare a public report that assesses whether any division of operational responsibilities hinders the Regional Transmission Organization in providing reliable, non-discriminatory and efficiently priced transmission service.

(ii) The Regional Transmission Organization must be the security coordinator for the facilities that it controls.

Note to paragraph (i)(3)(ii): The provision in this paragraph (i)(3)(ii) requires that the Regional Transmission Organization undertake the functions in its region currently assigned to security coordinators by NERC in "NERC Operating Policy 9—Security Coordinator Procedures." It is recognized that NERC "security coordinators" are relatively new and that they may not necessarily be permanent institutions. However, the functions NERC currently assigns to security coordinators are critical ones that should be performed by the entity with operational authority for transmission facilities within the region.

(4) *Short-term Reliability.* The Regional Transmission Organization must have exclusive authority for maintaining the short-term reliability of the grid that it operates.

(i) The Regional Transmission Organization must have exclusive authority for receiving, confirming and implementing all interchange schedules.

(ii) The Regional Transmission Organization must have the right to order redispatch of any generator connected to transmission facilities it operates if necessary for the reliable operation of these facilities.

(iii) When the Regional Transmission Organization operates transmission facilities owned by other entities, the Regional Transmission Organization must have authority to approve or disapprove all requests for scheduled outages of transmission facilities to ensure that the outages can be accommodated within established reliability standards.

(iv) If the Regional Transmission Organization operates under reliability standards established by another entity (*e.g.*, a regional reliability council), the Regional Transmission Organization must report to the Commission if these standards hinder it from providing reliable, non-discriminatory and efficiently priced transmission service.

(j) *Required functions of a Regional Transmission Organization.* The Regional Transmission Organization must perform the following functions. Unless otherwise noted, the Regional Transmission Organization must satisfy these obligations when it commences operations.

(1) *Tariff administration and design.* The Regional Transmission Organization must administer its own transmission tariff and employ a transmission pricing system that will promote efficient use and expansion of transmission and generation facilities. The Regional Transmission Organization must carry out this function by satisfying the standards listed in paragraphs (j)(1)(i) and (ii) of this section, or by demonstrating that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization must be the only provider of transmission service over the facilities under its control, and must be the sole administrator of its own Commission-approved open access transmission tariff. The Regional Transmission Organization must have the sole authority to receive, evaluate, and approve or deny all requests for transmission service. The Regional Transmission Organization must have the authority to review and approve requests for new interconnections.

(ii) The Regional Transmission Organization tariff must not result in transmission customers paying multiple access charges to recover capital costs for transmission service over facilities that the Regional Transmission Organization controls (*i.e*, no pancaking of transmission access charges).

(2) *Congestion management.* The Regional Transmission Organization must ensure the development and operation of market mechanisms to manage transmission congestion. The Regional Transmission Organization must carry out this function by satisfying the standards listed in paragraph (j)(2)(i) of this section, or by demonstrating that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The market mechanisms must accommodate broad participation by all market participants, and must provide all transmission customers with efficient price signals that show the consequences of their transmission usage decisions. The Regional Transmission Organization must either operate such markets itself or ensure that the task is performed by another entity that is not affiliated with any market participant.

(ii) The Regional Transmission Organization must satisfy this requirement no later than one year after it commences initial operation.

(3) *Parallel path flow.* The Regional Transmission Organization must develop and implement procedures to address parallel path flow issues within its region and with other regions. The Regional Transmission Organization must satisfy this requirement with respect to coordination with other regions no later than three years after it commences initial operation.

(4) *Ancillary services.* The Regional Transmission Organization must serve as a supplier of last resort of all ancillary services required by Order No. 888, FERC Stats. & Regs. ¶31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders. The Regional Transmission Organization must carry out this function by satisfying the standards listed in paragraphs (j)(4)(i)-(iii) of this section, or by demonstrating that an alternative proposal is consistent with or superior to satisfying such standards.

(i) All market participants must have the option of self-supplying or acquiring ancillary services from third parties subject to any restrictions imposed by the Commission in Order No. 888, FERC Stats. & Regs. ¶31,036 (Final Rule on Open Access and Stranded Costs), and subsequent orders.

(ii) The Regional Transmission Organization must have the authority to decide the minimum required amounts of each ancillary service and, if necessary, the locations at which these services must be provided. All ancillary service providers must be subject to direct or indirect operational control by the Regional Transmission Organization. The Regional Transmission Organization must promote the development of competitive markets for ancillary services whenever feasible.

(iii) The Regional Transmission Organization must ensure that its transmission customers have access to a real-time balancing market. The Regional Transmission Organization must either develop and operate such markets itself or ensure that this task is performed by another entity that is not affiliated with any market participant.

(5) *OASIS and Total Transmission Capability (TTC) and Available Transmission Capability (ATC).* The Regional Transmission Organization must be the single OASIS site administrator for all transmission facilities under its control and independently calculate TTC and ATC.

(6) *Market monitoring.* The Regional Transmission Organization must monitor markets for transmission services, ancillary services and bulk power to identify design flaws and market power and propose appropriate remedial actions. The Regional Transmission Organization must carry out this function by satisfying the standards listed in paragraphs (j)(6)(i)-(iv) of this section, or by demonstrating that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization must monitor markets for transmission service and the behavior of transmission owners, if any, to determine if their actions hinder the Regional Transmission Organization in providing reliable, efficient and nondiscriminatory transmission service.

(ii) The Regional Transmission Organization must monitor markets for ancillary services and bulk power. This obligation is limited to markets that the Regional Transmission Organization operates.

(iii) The Regional Transmission Organization must periodically assess how behavior in markets operated by others (e.g., bilateral power sales markets and power markets operated by unaffiliated power exchanges) affects Regional Transmission Organization operations and conversely how Regional Transmission Organization operations affect the performance of power markets operated by others.

(iv) The Regional Transmission Organization must provide reports on market power abuses and market design flaws to the Commission and affected regulatory authorities. The reports must contain specific recommendations about how observed market power abuses and market flaws can be corrected.

(7) *Planning and expansion.* The Regional Transmission Organization must be responsible for planning necessary transmission additions and upgrades that will enable it to provide efficient, reliable and non-discriminatory transmission service and coordinate such efforts with the appropriate state authorities. The Regional Transmission Organization must carry out this function by satisfying the standards listed in paragraphs (j)(7)(i) and (ii) of this section, or by demonstrating that an alternative proposal is consistent with or superior to satisfying such standards.

(i) The Regional Transmission Organization planning and expansion process must encourage market-driven operating and investment actions for preventing and relieving congestion.

(ii) The Regional Transmission Organization's planning and expansion process must accommodate efforts by state regulatory commissions to create multi-state agreements to review and approve new transmission facilities. The Regional Transmission Organization's planning and expansion process must be coordinated with programs of existing RTGs where necessary.

(iii) If the Regional Transmission Organization is unable to satisfy this requirement when it commences operation, it must file a plan with the Commission with specified milestones that will ensure that it meets this requirement no later than three years after initial operation.

(k) *Open architecture.* (1) Any proposal to participate in a Regional Transmission Organization must not contain any provision that would limit the capability of the Regional Transmission Organization to evolve in ways that would improve its efficiency, consistent with the requirements in paragraphs (i) and (j) of this section.

(2) Nothing in this regulation precludes an approved Regional Transmission Organization from seeking to evolve with respect to its organizational design, market design, geographic scope, ownership arrangements, methods of operational control and other appropriate ways if the changes are consistent with the

requirements of this section. Any future filing seeking approval of such changes must demonstrate that the proposed changes will meet the requirements of paragraphs (i) and (j) of this section and this paragraph (k).

Note: The following appendixes will not appear in the Code of Federal Regulations.

Appendix A—Staff Summary of FERC-Industry ISO Conferences

[Docket No. PL98–5–000]

During 1998, the Commission conducted a series of eight public conferences with the electric power industry for the purpose of examining its ISO policies. The Commission wanted to learn whether any changes to its policies that affect the development of ISOs and other forms of regional grid management structures are appropriate to further promote competition and reliability in bulk power markets. The Commission also wanted to learn whether it should also be more prescriptive in this area. The Commission also focused on the future of ISOs in administering the electric transmission grid on a regional basis. [1]

ISO Trust, Flexibility and Mandate

Participants largely agreed on the need for improved regional organizations to operate the grid and implement reliability rules. They emphasized the need for transmission operations to be structurally independent, trustworthy, and fair in order for competitive generation markets to flourish. There seemed to be a consensus that any Commission ISO policy should be flexible to meet the needs and characteristics of each region and its state commissions, and that the Commission should avoid any one-size-fits-all approach to ISO structure and functions that might stifle innovation. Participants differed, however, on whether the Commission should require or merely encourage ISOs.

Reasons offered as to why the voluntary approach to ISO formation has not worked uniformly across the Nation included: (1) some states that have not yet decided on retail access believe that an ISO inevitably will lead to retail access; (2) some low-cost states are concerned that ISOs and retail access will increase their electric rates because utilities will be able to use ISOs to sell their low-cost power elsewhere; (3) some see ISOs as overly expensive, burdensome, and bureaucratic; and (4) some see transmission access as having improved enough through the on-going implementation of Order Nos. 888 and 889.

Recommendations on what the Commission should do next ranged from wait and see, to act decisively now. Some in the first camp claimed that the Commission lacks the authority to mandate participation in ISOs. Some counseled that the Commission should continue to just nurture the formation of ISOs and allow development of organizations that best fit the local needs of a particular region and avoid stifling innovation by continuing the case-by-case approval of voluntary ISO submittals. Some suggested that the Commission merely define its basic objective as the availability of efficient and reliable transmission service on a non-discriminatory basis, and to encourage hold-outs to join.

Those conference participants favoring stronger action contended that functional unbundling has not worked well enough and that it is unrealistic to expect it to do so. Many claimed that some vertically integrated utilities are employing preferential reliability practices or manipulating postings of ATC and capacity benefit margin values to favor their own wholesale merchant functions. They further claimed that there is a reluctance to lodge complaints out of concern that the Commission may not take strong action or there might be reprisals by the utilities. Others contended that some utilities are impeding ISO formation by refusing to participate, and that, as long as ISO boundaries are drawn by the voluntary decisions of the transmission owners to pick and choose the ISO which most advances their individual corporate and competitive objectives, the result is likely to be ISOs whose shape and composition impede its ability to create a true competitive market. Strong action advocates also seemed to be looking for clear guidance on transmission pricing, operation of energy markets, and the phase-in of certain ISO responsibilities.

Many of those concerned about a patchwork of ISO grid coverage suggested that now is the time for the Commission to mandate ISOs (possibly tempered with incentives), or at least mandate participation in negotiations on ISO formation. Several suggested that the Commission work with the states to develop specific directives and guidelines as a way to assure that enough momentum on ISO formation is achieved. One guideline that was suggested would incorporate a standardized ISO tariff and a standardized set of rules governing reciprocity among ISOs. It would be coupled with a flexible ISO design that could accommodate varying regional needs. Others variously recommended (1) specification of minimum ISO functions as a basic model and letting the regions justify any departure therefrom; (2) ordering the formation of ISOs and allowing enough time for each region to develop a proposal that best suits its local needs; and (3) exercising all Commission authority to monitor and manage comprehensive ISO formation.

ISO Purposes and Functions

The many notions about what the proper functions of an ISO should be seemed to reflect what each participant saw as the critical regional objectives (*e.g.*, promotion of retail access; more efficient grid operation, planning and expansion; enhanced system reliability; elimination of loop flow issues; solution of "seams" problems between control areas; elimination of rate pancaking; improved congestion management; enhanced reserve sharing; establishment of one-stop shopping through creation of a regional OASIS; enhanced market monitoring, and improved real-time communication among all transmission entities). Accordingly, suggested ISO functions included: control area responsibilities; numerous security coordinator and reliability duties; impartial operation of a regional OASIS to improve ATC postings; administration of an ISO-wide tariff; generation redispatch duties to relieve congestion; and ancillary services markets coordination responsibilities.

Some participants argued, however, that certain functions should not be foisted upon ISOs. Some contended that it would be detrimental to the markets and the administration of ISOs if ISOs become involved with functions that are not natural monopolies such as power exchange activities because this would compromise the ISO's independence in fulfilling its primary transmission responsibilities. Many cautioned that an ISO should not be involved in market monitoring beyond data gathering tasks, due to the attendant administrative burden and cost, and because enforcement should be the sole prerogative of regulatory authorities.

ISO Size

Most participants agreed that, as a general proposition, bigger ISOs can be more effective than smaller ISOs, given the growth in unbundled power sales and the lessening of traditional cooperation among utilities that have now become competitors. For example, with regard to the connection between size and effective reliability management, it was pointed out that an excessive number of control areas in the Midwest has inhibited communication and coordination, and contributed to several of the Midwest's recent reliability "near misses."

Basically, participants saw the "proper" size as depending upon a number of factors: (1) The purposes and functions of the ISO (such as enhancing reliability or accommodating regional power markets); (2) the operating characteristics and make-up of the local regional transmission system; (3) being large enough to capture scale economies yet not too big to operate without difficulty and handle large volumes of next-hour transactions; (4) recognizing historic coordination arrangements, trading patterns, and load patterns; and (5) remaining responsive to local transmission concerns and conventions on such matters as how wide an area over which costs associated with transmission construction and generation redispatch should be spread.

Alternatives to ISOs

A number of participants counseled that the Commission should seriously consider alternatives to ISOs such as investor-owned transcos, and independent grid administrators or schedulers (IGA or ISA).

IGA/ISA supporters were concerned about what could be quickly implemented that would avoid the high costs that seem to be associated with comprehensive ISO initiatives, yet would provide immediate control over the more egregious actions of some transmission providers. IGA/ISA structures were described to include any of the following: (1) One-stop shopping through an OASIS that uniformly calculates ATC

[1] *See* Inquiry Concerning the Commission's Policy on Independent System Operators, Notice of Conference (dated March 13, 1998), and Notice of Panels for Conference (dated April 7, 1998). *See also*, Inquiry Concerning the Commission's Policy on Independent System Operators, Notice of Regional Conferences (dated April 27, 1998).

values; (2) independent coordination of reservations and power flow scheduling; and (3) fast-track dispute resolution. It was claimed that such structures would avoid cost-shifting controversies and congestion management complications because the IGA/ISA members would continue to operate their own transmission and set their own individual rates. While there was some support for IGA/ISA structures as an interim step toward full ISO formation, many participants expressed concern about the Commission approving "watered-down" versions of an ISO that fail to address pressing needs for grid expansion and pricing reform.

Transco supporters argued that a transco can offer everything that a full ISO can provide, plus the additional efficiency that is inherent in combining operation and ownership of transmission assets driven by the same corporate and market incentives. Transcos were also said to provide more opportunity for shareholders to benefit from the strong performance of any facilities placed under an ISO. As such, transcos were touted as the natural end-state of transmission restructuring. ISO supporters countered that the ISO structure need not foreclose passing incentive-rate revenues on to transmission owners. They also claimed that, unlike a transco, an ISO is not dependent upon the successful transfer of all of the transmission assets within a region and, if an ISO is sized wrong, it can be more readily corrected than a transco for the same reason.

Finally, some participants suggested that ISOs and transcos are actually complementary forms. Others claimed that who owns the transmission is irrelevant as long as the regional grid operator is independent; it is big enough to internalize loop flows; it directs region-wide transmission planning; and it allows for competitive bidding on the installation of new facilities to expand the grid.

ISO Pricing and Cost-shifting Concerns

Some participants supported differing forms of ISO rate structures: flow-based rates, distance-based pricing, average-cost based rates, and locational marginal cost-based pricing. Many cautioned that a Commission mandate on the use of any particular tariff structure would be a major obstacle to the voluntary formation of ISOs; therefore, they recommended that the Commission provide great deference to the needs of each region as to what locally is seen to be fair and reasonable pricing.

In particular, many participants raised concerns about cost-shifting within an ISO that might result from membership with significantly disparate embedded transmission costs and imposition of an ISO-wide access tariff that reflects some composite of such costs. These participants counseled that the Commission should allow "license plate" access rates that reflect only the cost of the transmission zone within the ISO in which the load to be served is located. One participant suggested, however, that even license plate rates can raise cost-shifting concerns, if the cost of an upgrade that is used primarily for the benefit of external loads is included in the cost basis for the affected zone.

Non-jurisdictional Transmission Participation

Most participants expressed the view that government-owned and other regional non-jurisdictional transmission owners need to fully participate in an ISO in order for it to be completely successful. It was suggested that this is especially true for the West, where large amounts of non-jurisdictional transmission is controlled by Bonneville Power Administration, Western Area Power Administration, Southwestern Power Administration, large municipals, cooperatives, public power districts, British Columbia Hydro, and the Alberta grid. Some participants wanted the Commission to provide guidance on how to bring public power and other non-jurisdictional transmission owners into an ISO. In this regard, some suggested that the Department of Energy needs to issue guidance to the federal power marketing agencies on their active support of any ISO initiatives. Public power participants, who strongly supported ISOs, expressed concern that any ISO participation on their part could adversely affect the financing of their facilities due to Internal Revenue Code "private-use" restrictions.

Existing Transmission Contracts

Some participants emphasized the need for ISOs to honor (grandfather) existing transmission contract arrangements to maintain any benefits that were bargained. Others emphasized the need for ISOs to abrogate any existing transmission contracts to eliminate any preferential transmission treatment. Those favoring grandfathering, however, acknowledged that it could become a very complicated administrative matter in the event that there is insufficient transmission capacity to serve everyone.

Panelists

The Commission held conferences in Washington, D.C. and in seven cities in different regions of the country.

Washington, D.C.

In the lead-off two-day conference held on April 15–16, 1998, in Washington, D.C., approximately 400 individuals attended each day. Panelists represented:

American Electric Power Company
American Public Power Association
California Independent System Operator
California Independent System Operator, Market Surveillance Committee (by Stanford University)
California Public Utilities Commission
Cameron McKenna LLP
Cinergy Energy Services, Inc.
Commonwealth Edison Company
Coalition For A Competitive Electric Market (by Enron Corporation)
Economic Analysis Group
Edison Electric Institute
Edison Electric Institute (by NERA)
Electric Power Supply Association.
Entergy Services, Inc.
Harvard University (John F. Kennedy School of Government)
Industrial Consumers (by Electricity Consumers Resource Council)
ISO New England
Members Systems of the New York Power Pool (by Putnam, Hayes & Bartlette, Inc.)
Mid-Continent Area Power Pool (by Morgan, Lewis & Bockius)
Montana Power Company
National Association of Regulatory Utility Commissioners (by Iowa Utilities Board)
National Rural Electric Cooperative Association
NGC Corporation
Pennsylvania Public Utility Commission
PJM Interconnection, L.L.C.
Public Utilities Commission of Ohio
Public Service Commission of the State of New York
Rhode Island Public Utilities Commission
Secretary of Energy's Task Force on Electric System Reliability
Sithe Energies, Inc. (By Economics Resource Group)
Transmission Access Study Group (by Wisconsin Public Power, Inc.)
Transmission Alliance (by Merrill Lynch)
Transmission Dependent Utility Systems (by Arkansas Electric Corporation
U.S. Department of Justice
U.S. Generating Company and PJM Supporting Companies (by Steptoe & Johnson LLP)
Wabash Valley Power Association, Inc.
Wisconsin Electric Power Company

Phoenix

Almost 90 people attended the May 28, 1998, Phoenix conference. Panelists represented:

Arizona Corporation Commission
Arizona Public Service Company
Automated Power Exchange, Inc.
California ISO
Desert STAR
K.R. Saline & Associates
Colorado Springs Utilities
Cyprus Climax Metals, BHP Copper, Phelps Dodge, ASARCO and Motorola (by Energy Strategies, Inc.)
Goldman Sachs & Co.
Northern California Power Agency.
Salt River Project Agricultural Improvement and Power District
Southwest Power Trading Council (by Enron Corp.)
Tri-State Generation and Transmission Cooperative, Inc.

Kansas City

About 90 people attended the May 29, 1998, Kansas City conference. Panelists represented:

City Utilities of Springfield, Missouri
Clarksdale Public Utilities Commission
Cooperative Power Association
Iowa Utilities Board
Kansas Corporation Commission
Mid-America Regulatory Conference (by Kansas Corporation Commission)
Midwest Coalition for Effective Competition (by MCES and Environmental Law and Policy Center)
Midwest ISO Participants (by Wisconsin Electric Power Company and Ameren Services)
Minnesota Department of Public Service

Missouri Office of Public Counsel
Missouri Public Service Commission
Nebraska Public Power District
Northern States Power Company
Public Utility Commission of Texas
Shook, Hardy, Bacon, LLP
Southwest Power Pool

New Orleans

The June 1, 1998, New Orleans conference panelists represented:

Arkansas Electric Cooperative
Entergy Corporation
Gulf Coast Power Marketers Coalition
Houston Industries Power Corporation, Inc.
Lafayette Utilities System
Louisiana Energy Users Group
Public Service Commission of Yazoo City, Mississippi
Southern Company Services, Inc.
Southwest Power Pool
Southwestern Public Service Company

Indianapolis

About two hundred people attended the June 4, 1998, Indianapolis conference. Among the panelists represented:

AMEREN
American Municipal Power of Ohio
Cinergy Services Inc.
Citizens Action Coalition of Indiana
Consumers Energy Company
Detroit Edison Company
Energy Michigan
FirstEnergy Corporation
Illinois Industrial Energy Consumers
Indiana Municipal Power Agency
Indiana Utility Regulatory Commission
Kentucky Public Service Commission
Madison Gas and Electric Company
Mid-America Regulatory Commissioners (by Michigan Public Service Commission)
Midwest Coalition for Effective Competition
Midwest ISO Participants
Michigan Public Power Agency
Minnesota Public Utilities Commission
Public Utilities Commission of Ohio
Wisconsin Electric Power Company

Portland

About 160 people attended the June 5, 1998, Portland conference. Panelists represented:

Automated Power Exchange
Bonneville Power Administration
California ISO
California Municipal Utilities Association
California Public Utilities Commission
Chelen County PUD (on behalf of Independent Grid Scheduler)
CIBC Oppenheimer Corp.
Columbia Falls Aluminum Company, et al.
Idaho Power Company
Idaho Public Utilities Commission
Industrial Customers of Northwest Utilities
Land and Water Fund of the Rockies Energy Project
Montana Department of Environmental Quality
Montana Power Company
Northern California Power Agency.
Oregon Public Utilities Commission
Pacific Northwest Generating Cooperative
PacifiCorp
Platte River Power Authority
Public Power Council
Public Service Company of Colorado
Puget Sound Energy, Inc.
Transmission Agency of Northern California
Turlock Irrigation District
University of California
Washington Utilities and Transportation Commission
Western Power Trading Forum
Western Regional Transmission Association

Richmond

About 55 people attended the June 8, 1998, Richmond conference. Panelists represented:

Blue Ridge Power Agency
LG&E Energy (on behalf of Midwest ISO Participants)
Mid-Atlantic Power Association
North Carolina Electric Membership Corporation
Old Dominion Electric Cooperative
TransÉnergie U.S., Ltd.
Virginia State Corporation Commission
Virginia Committee for Fair Utility Rates and Old Dominion Committee for Fair Utility Rates
Virginia Electric & Power Company

Orlando

The June 8, 1998, Orlando conference was attended by about 100 people. Panelists represented:

Dynergy
Enron Power Marketing (by Basford & Associates)
Florida Municipal Power Agency
Florida Power & Light Company
Florida Power Corporation
Florida Public Service Commission
Florida Reliability Coordinating Council, Inc.
Morgan Stanley & Company
Municipal Electric Authority of Georgia
National Grid Company of England and Wales
Seminole Electric Cooperative, Inc.

Other Commenters

Alabama Electric Cooperative, Inc.
Allegheny Power, et al.
Barbara R. Barkovich
California Department of Water Resources
California Electricity Oversight Board
California Independent Energy Producers Association
Central Illinois Light Company
Citizens Group Responsible Use of Rural & Agricultural Land
Commonwealth of Pennsylvania Utility Commission
Commonwealth of Virginia, Division of Energy Regulations
Commonwealth of Virginia State Corporation Commission
Consumer Counsel Office of the Attorney General of Virginia
Consumers Energy Company
Cooperative Power Association
CSW Operating Companies
CSX Transportation
D. Basford & Associates, Inc.
Dairyland Power Cooperative
Department of Energy, Bonneville Power Administration
Desert Southwest Power Trading Council
Dominion Resources Inc.
Economic Resources Group, Inc.
Electricities of North Carolina, Inc.
Electricity Consumers Resource Council, et al.
Energy Strategies, Inc.
Fiona Woolf
Georgia System Operations Corporation, et al.
Goldman, Sachs & Company
Gregory J. Werden
Gridco Commenters
Houston Industries, Inc.
IES Utilities Inc., et al.
Illinois Commerce Commission
Independent Grid Scheduler Organizing Group
Independent Power Producers of New York, Inc.
Indiana Energy Michigan
Indiana Office of Utility Consumer Counsel
Kentucky Utilities Company
Kentucky Public Service Commission
Large Public Power Council
Marija D. Ilic
Mid-Atlantic Public Service Commissions
Midwest Independent Transmission System Operator, Inc.
Midwest Municipal Intervenors, et al.
Minnesota Power Company
Minnesota Public Utilities Commission
Mississippi Office of Public Counsel
Montana Public Service Commission
Multiple Public Interest Organizations
New York Mercantile Exchange
New Mexico Industrial Energy Consumers
Northern Indiana Public Service Company
Northwest Power Plant Planning Council
Oak Ridge National Laboratory
Office of Ohio Consumers' Counsel
Oklahoma Corporation Commission
Oklahoma Gas and Electric Company
Orange & Rockland Utilities
Oregon Public Utilities Commission
Otter Tail Power Company
Pacific Gas & Electric Company
PECO Energy Company
Pennsylvania Office of Consumers Advocate
PJM Supporting Companies
Portland General Electric Company
Powersmiths International, Inc.
Project For Sustainable FERC Policy
ProLiance Energy, LLC
Public Service Commission of Wisconsin
Public Service Electric & Gas Company
Public Utilities Board of the City of Brownsville, Texas
Public Utility District No. 1 of Chelan County, Washington
Selkirk Cogen Partners, L.P.
Sierra Pacific Power
Southern California Gas Company, et al.
Southwest Transmission Dependent Utility Group
Staff of Bureau of Economics of the Federal Trade Commission
State of California Public Utilities Commission
State of Florida Public Service Commission
State of Idaho & Idaho Public Utilities Commission
State of Kansas Citizens' Utility Ratepayer Board's
State of Minnesota Public Utilities Commission
State of Montana Department of Environmental Quality
State of New York Public Service Commission
State of Rhode Island and Province Plantations

The Williams Companies Inc.
Transmission Operators of Public Service Company of Colorado
Tucson Electric Power Company
University of Arizona
Virginia Committee for Fair Utility Rates, et al.
Washington Department of Community, Trade and Economic Development Energy Policy Group
Western Area Power Administration
Wisconsin Intervenors
Wisconsin Public Power, Inc.
Wisconsin Public Service Corporation

Appendix B—Staff Summary of FERC Consultations With the States

[Docket No. RM99–2–000]

In Docket No. RM99–2–000, as part of a broader inquiry into its RTO policies, the Commission held a series of three regional conferences to elicit the views and recommendations of state regulatory authorities with respect to the development of independent RTOs and whether and how it should use its authority under section 202(a) of the Federal Power Act.[1] The Commission also wanted to learn whether the goals of full competition and non-discriminatory transmission access can be achieved in the absence of broad participation by transmission-owning utilities in RTOs. Conferences were held in St. Louis, Las Vegas, and Washington, D.C. in February 1999.

Need for Commission Mandate

There was little real dispute by participants over the need for independent and impartial regional grid management, whether it be for improved grid operation, increased reliability, identifying promising new generation locations, broadening markets by reducing rate pancaking, or all of these. Most of the states also recognized that the Commission is the necessary and appropriate facilitator for forming RTOs, due to its broad jurisdiction. However, comments as to how best the Commission should proceed next were mixed.

One state wondered whether the Commission has the authority to mandate RTOs. Several Northeastern and Mid-Atlantic states that already have strong ISOs were concerned that the Commission might disturb their ISOs before an adequate period of time has elapsed to reveal their strengths and weaknesses. One state suggested that the Commission should look into setting up a joint board of state and federal regulators on RTO issues. Some Southeastern states saw no need for a Federal policy on RTOs right now. They felt that the grid is operated adequately and preferred to let the market sort RTO developments.

States west of the Appalachians generally recognized the need for structural independence of transmission through RTOs beyond functional unbundling sooner rather than later and saw a need for strong Commission leadership on RTO formation. They differed on the urgency and the necessary extent of Commission involvement. Many of the states advocating a more aggressive role were located in the Midwest, which had experienced price spikes during the summer of 1998.

One state insisted that Commission action is needed to quicken the pace of RTO formation so that development of competitive electricity markets is not delayed. One vigorously complained about the persistent lack of fuller RTO participation in the Midwest and the possible strategic advantage to vertically integrated utilities not participating. To counter the fragmentation in the Midwest, it recommended that the Commission mandate utility participation or, at a minimum, eliminate pancaked transmission rates within each regional reliability council. Another suggested that the Commission interpret any utility's refusal to join an RTO as an indicator of undue discrimination. One recommended that the Commission strongly promote fuller participation in RTOs by using a combination of "carrots" and "sticks" as incentives.

Flexibility

A pervasive theme was the need for the Commission to avoid taking a one-size-fits-all approach to RTOs. Many states recommended that, if the Commission wants to establish RTO policy pursuant to its section 202(a) authority, the policy must be implemented in a way that adequately recognizes any regional differences in industry structures. One Midwestern state counseled that the Commission should partner with the states to develop a memorandum of understanding (MOU) on regional transmission matters. The MOU would outline common desires and objectives, describe the regulatory tools to get there, and the circumstances under which the tools would be used.

Other states suggested that the Commission, before it considers taking any stronger action, issue guidelines and allow enough time for each state to determine which are appropriate for it in forming regional RTOs. The guidelines would reflect determinations on such issues as how to encourage participation by and otherwise deal with non-jurisdictional transmission entities; whether to allow a state to opt out of a mandatory RTO policy; and how to ensure that no state's economy is harmed by an RTO. Several states suggested that cost/benefit analyses be done for each region. Finally, numerous states recommended that the Commission not mingle retail competition issues with RTO issues, contending that retail choice is a state prerogative.

RTO Size

Several states were concerned about how large is large enough for an RTO, and how the Commission expects to set the proper regional boundaries. In the East, states served by established ISOs expressed concern that their ISOs might have to incur additional costs for modifications that might be required to meet a potential Commission size criterion before market forces have had the chance to suggest an appropriate size. Some suggested that because the existing ISOs are so crucial to promoting retail competition in states that have already adopted retail choice, the Commission should carefully consider any order that would expand, merge, or restructure an existing ISO. Some states cautioned that expanding their existing ISOs beyond a certain point might also lead to reliability problems or inheriting problems from adjacent regions.

One state recommended that only minimum size criteria be established rather than the specific locations of boundaries. Other states recommended that, if the Commission insists on establishing regional boundaries, that it consider the relative costs and benefits of an RTO sized according to each regional boundary set. One state suggested that the Commission rely on the existing NERC regional councils as the starting point for determining proper RTO boundaries. Another state suggested that the Mid-Continent Area Power Pool (MAPP) and Mid-American Interconnected Network (MAIN) interfaces should be placed within a single RTO. Some western states contended that, while only one regional reliability council serves the West, many non-jurisdictional cooperative and government utilities control such a substantial amount of transmission that creating RTOs in the West will be difficult absent clear direction from the Commission.

Alternative Forms of RTOs

While several states argued that competing ISO and transco structures could lead to further fragmentation and limited RTO operations, others argued that mandating specific forms of RTOs now would impede the ability of the states and regions to adopt models that are best suited for their particular needs and that the Commission should not lock in particular RTO structures but should instead retain flexibility to address changing future needs. One state favored a non-profit ISO structure, because it doubted that the industry would lend itself to the development of any transco with sufficient geographic coverage and adequate independence from generation interests. It noted, however, that if a for-profit transco could meet the size and independence criteria, the transco would have advantages over an ISO in the form of a stronger business orientation and superior access to capital for grid expansion.

Transmission Cost Shifting and Low Power Cost States

Many states counseled that the Commission should allow a region to opt-out of an average cost based RTO-wide rate, if such a rate would shift highly disparate embedded transmission costs among its RTO customers and force some to suffer transmission rate increases. Many western states suggested that concern over the enhanced ability of utilities to export their low cost power to other regions through an RTO, as well as concerns about transmission cost shifting, not only led to the demise of the IndeGo ISO but has thwarted further RTO development in the West.

[1] *See* Regional Transmission Organizations, Notice Of Intent To Consult Under Section 202(a) dated November 24, 1998, and Notice Of Dates And Locations For Consultation Sessions With State Commissions (dated January 13, 1999).

Panelists

St. Louis

About 120 people attended the February 11, 1999, conference in St. Louis. Panelists represented commissions in:

Arkansas
Florida
Illinois
Indiana
Iowa
Kansas
Kentucky
Michigan
Minnesota
Missouri
Nebraska
North Dakota
Ohio
Oklahoma
South Dakota
Tennessee
Texas
Wisconsin

Las Vegas

About 96 people attended the February 12, 1999, conference held in Las Vegas. Panelists represented commissions in:

Arizona
California
Colorado
Idaho
Montana
Nevada
New Mexico
Oregon
Utah
Washington
Wyoming

Washington, D.C.

The panelists at the February 17, 1999, conference in Washington, D.C. represented commissions in:

Alabama
Connecticut
District of Columbia
Georgia
Maryland
Massachusetts
Mississippi
New Jersey
New York
North Carolina
Pennsylvania
Rhode Island
West Virginia

Other Commenters

Canadian Electricity Association
ISO New England
Mid-American Regulatory Commissioners
National Association of Regulatory Utility Commissioners
New England Conference of Public Utilities Commissioners, Inc.
Regional Electric Power Cooperation
Virginia State Corporation Commission
Western Interstate Energy Board

Appendix C—Existing Configurations

This Appendix depicts the three existing configurations discussed in Section III.D.2: the three electric interconnections within the continental United States, the ten NERC reliability councils, and the twenty-three NERC security coordinator areas.

[The attachments to this Appendix are available for public inspection and copying during normal business hours in the Public Reference Room at 888 First Street, N.E., Room 2A, Washington, D.C. 20426, and through the Commission's Records and Information Management System (RIMS). RIMS is available remotely via Internet through FERC's Home page using the RIMS link or the Energy Information Online icon.]

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