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RAILROAD REVENUE ADEQUACY

REPLY COMMENTS OF NORFOLK SOUTHERN RAILWAY COMPANY

James A. Hixon
William A. Galanko
John M. Scheib
David L. Coleman
Garrett D. Urban
Norfolk Southern Railway Co.
Three Commercial Place
Norfolk, VA 23510

G. Paul Moates
Raymond A. Atkins
Matthew J. Warren
Hanna M. Chouest
SIDLEY AUSTIN LLP
1501 K Street, N.W.
Washington, DC 20005
(202) 736-8000

Counsel for Norfolk Southern Railway Company

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INTRODUCTION[1]

The Opening Comments in this proceeding make clear that it is time for the Board to abandon the independent revenue adequacy constraint. On the one hand, Norfolk Southern Railway Company ("Norfolk Southern") and other commenters demonstrated both the significant economic problems that would be created by an independent, top-down revenue adequacy constraint and the fact that the Board's current robust suite of rate reasonableness remedies already incorporates revenue adequacy principles and provides real and effective constraints on railroad pricing. And on the other hand, the commenters who call for an independent revenue adequacy constraint were unable to articulate any economically principled structure for it. Nor did these commenters explain how the Board could adopt such a top-down constraint without creating substantial disincentives for the capital investments that are sorely needed to improve service and address increasing capacity demands. An independent top-down revenue adequacy constraint is unwise and unnecessary, and the Board should reject it. Shippers who believe that a railroad's rates are higher than necessary for the railroad to be revenue adequate can test that claim using the Stand Alone Cost ("SAC"), Simplified Stand Alone Cost ("Simplified SAC"), or Three Benchmark methodologies, and no additional "revenue adequacy" methodology is necessary.

Comments in favor of an independent revenue adequacy constraint all rely on three false premises. First, these commenters assume that all Class I railroads are revenue adequate. But shippers provide virtually no economic support for that assumption. Most shipper-commenters merely cite to the Board's annual revenue adequacy calculations, without acknowledging the well-

[1] In addition to filing these Reply Comments, NS also joins in the Reply Comments of the Association of American Railroads.

known shortcomings of those calculations. Others simply assert that railroads are indisputably revenue adequate and even demand that the Board shut its eyes to any evidence to the contrary. But the reality is that the annual revenue adequacy calculations are unsuited to assessing long-term revenue adequacy, in part because of serious methodological flaws in the annual calculations, such as the failure to use replacement costs or to properly account for deferred taxes.

The second false premise of commenters favoring an independent revenue adequacy constraint is the assumption that a finding of revenue adequacy justifies and must immediately result in a transfer of money from the revenue adequate railroad to certain of its shippers. Again, this assumption is unsupported by any economic justification or consideration of the consequences of such a policy, which would decimate incentives for capital investments and efficiency improvements and threaten the overall financial health of the industry. Shippers' proposed methods for transferring wealth from revenue adequate railroads to selected shippers ignore the serious damage that such wealth transfers would inflict on the overall transportation network, which has a critical need for the capital investments and efficiency improvements that these commenters would defund.

The third false premise of the comments favoring an independent revenue adequacy constraint is the claim that shippers need another rate reasonableness methodology because of the alleged limitations of the SAC test. After considerable time and effort, the Board has created multiple rate reasonableness methodologies tailored to all varieties of cases, and the Board has worked to refine and simplify its rate case rules in ways that streamline the litigation process for shippers that believe their rates are unreasonably high. But some shipper commenters are willfully blind to these reforms, and instead allege that they have no effective access to rate reasonableness processes. On the contrary, the Board's existing rate remedies are robust and accessible, and they place a significant constraint on railroad pricing. There is no need to create yet another rate constraint that threatens to create many more problems than it would solve.

Part I of these Reply Comments discusses shippers' false assumption that all railroads are indisputably revenue adequate. Part I reiterates the serious errors in the Board's annual revenue adequacy calculations and shows how the Board's actual consideration of revenue adequacy on a replacement cost basis in the *DuPont* case[2] contradicts the claims of shipper-commenters that all railroads are plainly charging rates higher than necessary to achieve revenue adequacy. Part II discusses the shipper proposals for an independent revenue adequacy constraint and details the serious shortcomings and problems that would be created by adopting such proposals. Part III addresses the perennial complaints shippers make about the Board's current rate reasonableness processes and explains why the Board's current processes provide effective and accessible constraints on rail rates. Part IV concludes by discussing the pressing need for infrastructure investments and capital improvements—both of which would be undercut if shipper-commenters obtain their objective of indiscriminately transferring wealth from supposedly "revenue adequate" railroads to a subset of shippers.

I. SHIPPER COMMENTS REGARDING THE FINANCIAL STATE OF THE INDUSTRY ARE CONCLUSORY AND GLOSS OVER SERIOUS QUESTIONS ABOUT HOW TO MEASURE REVENUE ADEQUACY.

Shippers' comments all proceed from the premises that railroads are indisputably revenue adequate and that shippers indisputably are entitled to

[2] *E.I. du Pont de Nemours & Co. v. Norfolk So. Ry. Co.*, STB Docket No. 42125 (corrected decision served Oct. 3, 2014) ("*DuPont*").

some recovery because of this alleged revenue adequacy.[3] While Norfolk Southern and other railroads are financially healthier than they were at the time of the Staggers Act, there is no reason to believe that railroads are revenue adequate using economically rigorous measures.

A. Conclusory Assertions that All Railroads Are Revenue Adequate Are Unsupported and Wrong.

Some shipper commenters simply announce as an opening conclusion that railroads have "achieved" revenue adequacy and quickly move on to discuss ways that the Board could begin transferring wealth from railroads to certain shippers. *See, e.g.*, AECC Opening Comments at 2 (beginning comments with claim that supposed "achievement of revenue adequacy" marks a "turning point" at which Board can return to more "traditional" forms of controlling railroad earnings). Shippers also take as a given that any earnings above the cost of capital are presumptively ill-gotten gains that ought to be disgorged from railroads and returned to selected shippers.[4] Again, shippers provide no support whatsoever for this conclusion, which is at odds with the fundamental understanding of *Coal Rate Guidelines* that revenue adequacy is intended to be a floor on railroad earnings—not a ceiling.[5]

This conclusory assumption that all railroads are plainly revenue adequate is contradicted by the evidence actually presented on opening. As AAR witness Roger Brinner demonstrated, railroad returns are lower than

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[3] *See, e.g.*, ARC Opening Comments at 13 (claiming that "with revenue adequacy either achieved or imminent for all major railroads," "the time has come" for the Board to begin revisiting its regulatory policies); AECC Opening Comments at 2 (claiming that "achievement of revenue adequacy" should mark "turning point" for Board to begin controlling railroad earnings); Concerned Shipper Associations Opening Comments at 6.

[4] *See, e.g.* AECC Opening Comments at 5, 22-23 (defining any "earnings above the revenue adequacy level" as "supracompetitive earnings" and proposing that such earnings be "rolled back" and returned to certain shippers).

[5] *See* NS Opening Comments at 55-56 & n.144.

average returns of other industries. *See* AAR Opening Comments, V.S. Brinner at 9-13. Indeed, the rail industry's average rate of return relative to its cost of capital is markedly lower than the average industry returns of the shipper interests that are seeking more rate regulation. For example, rail industry returns on invested capital are far lower than returns in the chemicals industry and lower relative to average cost of capital than returns for electric utilities. *Id.* at 13, Ex. 2. The claims of some shippers that railroad returns are conclusive proof that railroads are overcharging shippers in a way that demands immediate Board intervention cannot be reconciled with the fact that railroad returns are not unusually high when compared to other industries.

Some shippers go so far as to ask the Board to categorically refuse to consider any evidence that would suggest individual railroads or the industry as a whole are not revenue adequate. For example, the Joint Coal Shippers take the blatantly result-oriented position that the Board should not consider any changes "that would make any Class I railroad appear to be farther away from revenue adequacy than the current test indicates."[6] Accuracy is apparently less important to these shippers than a guaranteed outcome. Still worse, AECC claims that "the Board should not concern itself" with evidence that individual rail carriers are experiencing revenue shortfalls and instead should simply assume that all railroads are revenue adequate and that any shortfalls are due to inefficient management.[7]

[6] Joint Coal Shipper Opening Comments at 2 ("*No* changes should be adopted that would make any Class I railroad appear to be farther away from revenue adequacy than the current test indicates.").

[7] AECC Opening Comments at 9-12 ("As long as overall market conditions provide a realistic opportunity for carriers to earn adequate returns, the Board should not concern itself with shortfalls that a particular carrier may experience relative to its peers at any given point in time.").

The outcome-oriented nature of these proposals is demonstrated by the Joint Coal Shipper attempts to transform revenue adequacy determinations into a "heads I win, tails you lose" system where railroads would be bound by certain metrics creating irrebutable presumptions of revenue adequacy, but shippers would not be so bound and would have the right to argue for revenue adequacy using alternative measures. *See* Joint Coal Shipper Opening Comments at 21-22 & 25. Such a one-sided approach to revenue adequacy is patently biased and inconsistent with the Board's statutory obligations to allow rail carriers to earn adequate revenues—particularly in light of the shippers' claim that a finding of revenue adequacy should automatically result in wealth transfers from railroads to shippers.

B. Claims That Annual Revenue Adequacy Determinations Are Evidence of Long-Term Revenue Adequacy Are Wrong.

Shipper commenters use the Board's annual revenue adequacy findings as supposedly conclusive evidence of revenue adequacy—precisely how the Board has long cautioned parties not to use the annual calculations.[8] The agency has "stress[ed]" that the mechanical annual revenue adequacy calculations are not "determinative or conclusive of the revenue adequacy of the carriers involved."[9] Shipper commenters fail to acknowledge this consistent, longstanding precedent that the agency will not rely on the annual findings in a particular rate case, and they provide no reason why the Board should reconsider it.

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[8] *See, e.g.*, Joint Coal Shippers Opening Comments at 12-13; Concerned Shipper Associations Opening Comments at 5-6.

[9] *Adequacy of Railroad Revenue – 1978 Determination*, 362 I.C.C. 199, 201 (1979) ("We wish to stress that our findings here will not be the determinative factor in other proceedings affecting railroad revenue."); *Railroad Revenue Adequacy – 1984 Determination*, 1 I.C.C.2d 615, 620 (1986) ("in rate reasonableness proceedings under Section 10701a, we do not treat the findings made under our current methodology as determinative or conclusive of the revenue adequacy of the carrier involved unless the parties present no other evidence relevant to that issue"); *see also* NS Opening Comments at 37-38 & nn. 99-102 (citing multiple instances where the agency held that annual determinations would not be determinative of revenue adequacy).

Indeed, the record plainly shows why annual determinations are too inaccurate to be used as conclusive evidence of revenue adequacy. Perhaps the most critical flaw is the fact that annual determinations do not use replacement costs. *See* Norfolk Southern Opening Comments at 71-74; AAR Opening Comments at 27-30; CSXT Opening Comments at 3-13. The consensus of economic experts is clear, longstanding, and overwhelming: any accurate measure of revenue adequacy must use the replacement cost of railroad assets, not their book value. In 1985 "dozens of the leading economists of the day" submitted a joint statement to the ICC urging that revenue adequacy determinations be based on "the replacement value of rail assets."[10] That consensus was reaffirmed in the opening comments of this proceeding, in which multiple respected economists urged the Board to use replacement costs for any measurement of revenue adequacy.[11]

Indeed, the consensus in favor of replacement costs is shared by some of the shipper commenters (at least when they are not arguing before the Board). For example, Edison Electric Institute ("EEI")[12] has argued strenuously to its members' own regulator that replacement costs are superior to book value estimates. In comments before the Federal Energy Regulatory Commission on a proposal to reform pricing to improve incentives for new investment, EEI urged

[10] *See* Norfolk Southern Opening, V.S. Cornell at 18 n.38 (quoting Economists' Statement on Support of Staggers Act (Feb. 25, 1985) ("The appropriate standard for determining the adequacy of railroad revenues is a rate of return equal to the current cost of capital on the replacement value of all rail assets that are required to meet the demands for railroad service, regardless for the source of funds used in investing in those assets.")).

[11] *See, e.g. id.*, V.S. Cornell at 13-19; AAR Opening Comments, V.S. Kalt at 28-31; Union Pacific Opening Comments, V.S. Murphy at 10-11.

[12] Edison Electric Institute is the trade association for shareholder-owned electric companies, including Ameren Missouri, CLECO Corporation, and Entergy Corporation—all of whom filed comments in this proceeding as members of the Western Coal Traffic League. *See* EEI, *U.S. Member Company Links*, *available at* http://www.eei.org/about/members/uselectriccompanies/Pages/usmembercolinks.aspx.

FERC to use the "market value of equity" rather than "book value" to improve the accuracy of its calculations.[13]

The agency itself has recognized that replacement costs are superior to historical book value for determinations of revenue adequacy. The ICC observed on several occasions that replacement cost valuation was "preferable" to original cost valuation (*i.e.*, using book value) because it "may better reflect the true economic costs associated with an investment."[14] And the agency has held that using replacement costs is particularly "necessary for the attraction and retention of capital in maximum rate cases."[15] The Board has similarly recognized the theoretical preferability of replacement costs, even when finding that a replacement cost approach is only practicable in the context of an individualized rate proceeding.[16]

Shipper commenters have not presented any evidence to counter the overwhelming expert consensus in favor of using replacement costs for any

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[13] *See* Comments of the Edison Electric Institute on the Notice of Proposed Rulemaking Promoting Transmission Investment Through Pricing Reform, FERC Docket No. RM06-4-000, at 13-14 (Jan. 11, 2006) (Attachment A):

> In addition, Commission staff uses the market value of equity to estimate the market cost of equity, then applies this rate of return to the book value of equity to calculate the equity return component of revenue requirements. This is fundamentally inconsistent. For utilities whose market to book ratio exceeds 1:1, it means they are unable to achieve the market required return estimated by the DCF. The solution is to apply DCF results to the market value of equity.

[14] *Standards for Railroad Revenue Adequacy*, 364 I.C.C. 803, 818 (1981) ("Standards *I*"); *see also Standards for Railroad Revenue Adequacy*, Ex Parte No. 393 (Sub-No. 1), 3 I.C.C.2d 261, 277 (1986) ("current cost accounting is theoretically preferable to original cost valuation") ("*Standards II*").

[15] *Arkansas & Missouri R.R. Co. v. Missouri Pac. R.R. Co.*, 6 I.C.C.2d 619, 627 (1990) ("However well A&M might have struck its bargain with Burlington Northern, its ability to renew and replace its assets will depend on its ability to attract capital at the replacement cost. Consequently, A&M should not now be forced to underprice current services by our adoption of a valuation methodology that bears no relationship to the replacement cost methodology we have found necessary for the attraction and retention of capital in maximum rate cases.").

[16] *See Association of Am. RRs. – Pet. Regarding Methodology For Determining R.R. Revenue Adequacy*, Ex Parte No. 679 (Oct. 24, 2008).

determination of revenue adequacy. While the Board has argued that the use of replacement costs is impractical for the annual revenue adequacy calculations, that rationale cannot justify not using replacement costs for a definitive finding of long-term revenue adequacy that could constrain a railroad's rates.[17] Shipper commenters' position that the Board should base rate constraints solely on patently flawed mechanical measures of revenue adequacy is an invitation for arbitrary and capricious decisionmaking.

In addition, the annual revenue calculations are inaccurate because the Board incorrectly deducts deferred taxes from the investment base.[18] As Professor Brad Cornell explained on behalf of Norfolk Southern, excluding deferred taxes from the investment base creates a powerful disincentive for railroad investment.[19] In short, the annual findings are too imprecise to be used for any purpose other than as a directional guide to the relative general financial health of the industry.

In the same vein, shippers offer no support for their proposal that one or four years' worth of annual determinations is sufficient to declare a railroad to be revenue adequate on a long-term basis.[20] A four-year period is plainly an insufficient amount of time to determine revenue adequacy, which the agency has recognized is "a long term concept."[21] Indeed, the unusually long useful lives of railroad assets counsels in favor of using a longer period.[22] As Professor

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[17] *See id.*

[18] *See* NS Opening Comments at 74-76.

[19] *See id.*, V.S. Cornell at 23.

[20] *See* Joint Coal Shipper Opening Comments at 24 (arguing for a 4-year period); AECC Opening Comments at 22-24 (proposing that railroad revenues be given to shippers if "in any year adequate revenues are achieved").

[21] *Coal Rate Guidelines - Nationwide*, 1 I.C.C.2d 520, 536 (1985) ("*Coal Rate Guidelines*").

[22] Shipper witnesses in other proceedings before the Board have conceded that railroad assets are "long-lived." Opening Comments of the Western Coal Traffic League, V.S. Traintis at 7, Ex Parte 664 (Sub-No. 2) (filed Sept. 5, 2014).

Cornell explained on Opening, "[a]ny period short of the full life of railroad assets is too short to make a fully informed assessment."[23] In other contexts, some shipper groups have similarly recognized the need to take a long-term view when assessing adequate returns on infrastructure investments. For example, Edison Electric Institute has argued to FERC that "adequate returns on investments in [infrastructure] must be set with a long-term perspective that will provide regulatory certainty and continuity throughout both the typical five to seven year project construction timeline and the 30-40 year life of the transmission asset."[24]

C. The Board's Recent Finding That the DuPont SARR Would Not Be Revenue Adequate Contradicts Shipper Claims That Norfolk Southern As a Whole Is Revenue Adequate.

The assertions of shipper comments that Norfolk Southern and other railroads are indisputably revenue adequate are irreconcilable with the record in *DuPont v. Norfolk Southern*, Docket No. NOR 42125. As the Board has recognized, a SAC analysis determines what a railroad "needs to charge to earn 'adequate' revenues on the portion of its system that is included in the system of the SARR."[25] SAC thus directly measures revenue adequacy on the line segments used for the shipments whose rates are being challenged. More specifically, the Stand Alone Railroad's ("SARR's") revenues from the selected traffic group are derived from the defendant railroad's actual and projected revenues from that traffic. SAC then assesses the costs of serving that traffic and uses a discounted cash flow analysis to determine whether the SARR's revenues exceed its operating and capital costs, including a reasonable return on investment (as

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[23] Norfolk Southern Opening Comments, V.S. Cornell at 28.

[24] Reply Comments of the Edison Electric Institute, FERC Docket No. RM11-26-000, at 8 (May 21, 2012) (Attachment B).

[25] *Pub. Serv. Co. of Col. d/b/a Xcel Energy v. BNSF Ry. Co.*, STB Docket No. 42057, at 6 (Jan. 19, 2005) ("*Xcel Reconsideration*").

measured by the cost of capital).[26] As a result, "the SAC test is designed to take into account the railroad's need for revenue adequacy 'on the portion of its system that is included in the system of the SARR.'" *BNSF Ry. Co. v. Surface Transp. Bd.*, 453 F.3d 473, 480 (D.C. Cir. 2006).

SAC thus represents a real rate constraint that tightens as a railroad approaches revenue adequacy. Because the SARR's revenues are based on the railroad's revenues, then increased rates and revenues would be attributable to the SARR and would make it easier for complainants to prevail in SAC cases. Thus, if a railroad raises its rates to the point that it is earning more than it needs to be revenue adequate on any particular segment of its system, it will be vulnerable to SAC or Simplified SAC cases brought by any shipper on that segment. In this way, SAC is more stringent (*i.e.*, more favorable to a complainant) than a top-down revenue adequacy constraint, which only would apply if a railroad were revenue adequate across its entire system.

The recent *DuPont* case is an apt example, because it is a case in which the complainant proposed a SARR that would handle 92% of Norfolk Southern's shipments and replicate the core of the NS network. *See* Reply V.S. Baranowski at 2-3. If Norfolk Southern as a whole were truly a revenue adequate railroad, then a SAC analysis for the core lines of its network should have shown a SARR that earned more than its cost of capital. (This is particularly so because the SARR in *DuPont* was modeled to be markedly <u>more</u> efficient than the real-world

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[26] Simplified SAC similarly measures the railroad's revenue adequacy on the portions of the network at issue. The primary difference between SAC and Simplified SAC is that SAC measures operating costs through a granular examination that allows the shipper to posit that the SARR would be more efficient than the defendant railroad itself, while Simplified SAC uses URCS costs as a low-litigation-cost alternative.

Norfolk Southern and the shipper received the benefit of not needing to construct all NS's infrastructure.[27])

That is not what the SAC result showed. On the contrary, the Board's analysis showed that the capital requirements for the *DuPont* SARR were higher than Norfolk Southern's Net Railway Operating Income ("NROI") for its entire system.[28] The green line in Table 1 represents the necessary capital recovery for the *DuPont* SARR (as calculated in the Board's October 3 decision). The blue bars represent NS's systemwide NROI for the corresponding years.[29] In every year, NS's actual <u>systemwide</u> NROI has been less than the capital requirements for the DuPont SARR.

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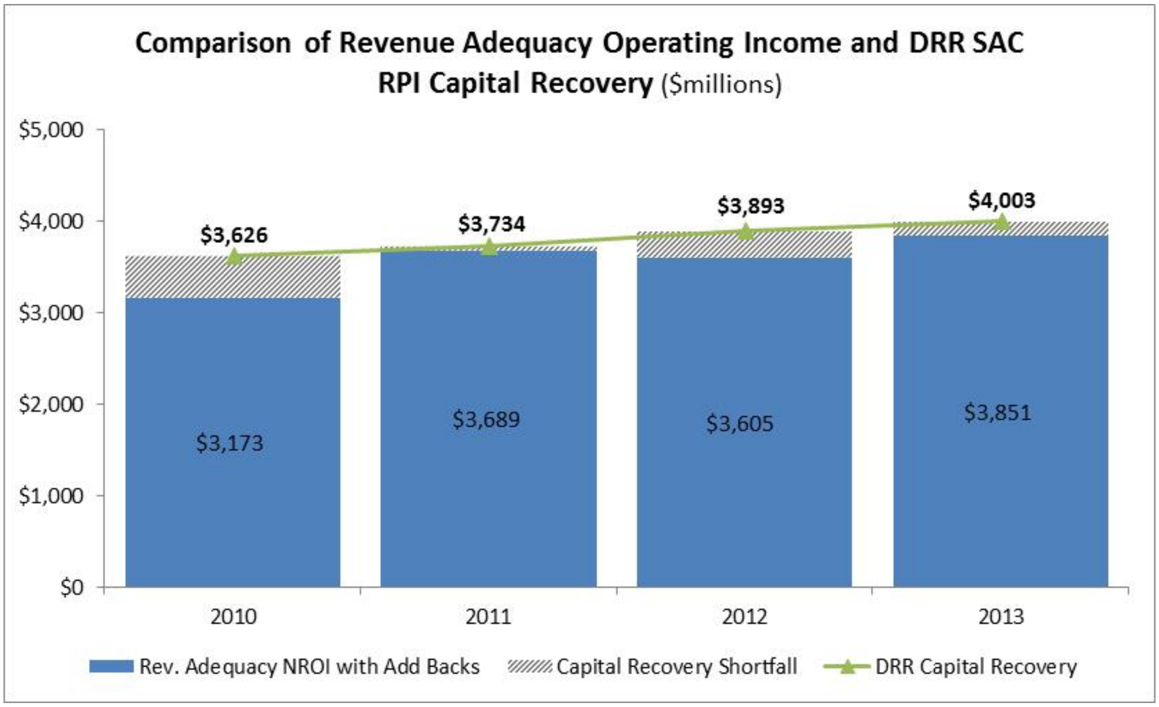
[27] *See* NS Reply Evidence at I-2, I-15, *DuPont*, STB Docket No. 42125 (filed Nov. 30, 2012) (showing that 2009 operating ratio for NS Reply SARR was 69.9%, substantially superior to that of NS or any other Class I railroad that year).

[28] The calculations in Table 1 are explained in the enclosed Reply Verified Statement of Michael Baranowski.

[29] To enable an accurate comparison to the SAC analysis, depreciation and income taxes have been added to NS's actual NROI to produce the Revenue Adequacy NROI shown in blue on Table 1. *See* Baranowski Reply V.S. at 5.

Table 1



A key difference between the *DuPont* result and the result of the Board's annual revenue-adequacy calculations is that the *DuPont* SAC analysis uses replacement costs and not book value. The comparison above is thus an apt demonstration of the serious distortions that are caused by relying on book values rather than replacement cost values when estimating the costs of rail infrastructure. It is also definitive, recent evidence disproving shippers' conclusory assertions that all railroads are unquestionably revenue adequate.

* * *

Are railroads financially stronger today than they were three decades ago? Of course they are, and the financial health of the railroad industry today is a credit both to the railroad personnel who revitalized the industry with innovations, hard work, and prudent investments and to the wise regulatory policies of Congress, the ICC, and the Board. But improved financial health does not equate to long-term revenue adequacy. The Board's annual revenue adequacy determinations are only a shorthand method of determining whether the railroads are trending in the right direction in light of the Board's statutory directive to help railroads achieve revenue adequacy. Annual revenue adequacy determinations are far too imprecise to be used in connection with an individual rate constraint. *See* Norfolk Southern Opening Comments at 71-76 & Cornell V.S. (describing in great depth the pervasive measurement errors in the Board's annual revenue adequacy findings).

II. SHIPPERS' ARBITRARY PROPOSALS LACK ANY ECONOMIC FOUNDATION AND REVEAL THE INHERENT PROBLEMS WITH THE ANTIQUATED REVENUE ADEQUACY CONSTRAINT.

As NS demonstrated on opening, regulators worldwide are abandoning traditional "cost-plus" rate of return regulation because they are increasingly aware of the drawbacks of such an approach. *See* Norfolk Southern Opening Comments at 54-55 & V.S. Sappington at 3-4, 10-11. As Professor Sappington explained, performance-based regulation has been displacing traditional rate of return regulation both in the United States and overseas, largely because of the poor incentives created by a regulatory policy of capping earnings at a level the regulator deems to be sufficient. *See* V.S. Sappington at 2-4. Conversely, performance-based regulations work to limit abuses of market power while retaining incentives for regulated companies to improve earnings by innovating and enhancing service. *See id.* at 3-6 (showing that SAC is "a form of [performance based regulation]"). Professor Sappington explained that:

> Strict earnings regulation in general, and [rate of return regulation] in particular, reflects the misguided premise that regulators serve consumers well by systematically precluding regulated suppliers from securing anything more than normal earnings. This premise ignores the fact that a policy that limits a supplier to normal earnings—regardless of its performance—provides the supplier with little or no incentive to excel in the marketplace. <u>In particular, stringent earnings regulation provides no incentive for the</u>

> regulated firm to engage in the challenging, costly processes of discovering more efficient means of operation and identifying and fulfilling the needs and desires of consumers.
>
> The more enlightened philosophy underlying [performance-based regulation] is that all parties can gain when regulated suppliers are motivated by the prospect of financial reward to discover innovative ways to operate more efficiently and to serve the best interest of consumers.[30]

Indeed, even Concerned Shipper Association witness Gerald Faulhaber acknowledges that "rate-base rate-of-return calculations [have been] virtually abandoned in this country (except at the STB)." Concerned Shipper Association Opening Comments, V.S. Faulhaber at 3.

Only a single commenter asks the Board to consider traditional, antiquated rate of return regulation.[31] Yet shipper-commenters nonetheless propose alternative ways to transfer wealth from railroads to certain rail shippers. Each of these alternatives share the same fundamental failings. They are not supported by any economic theory or the testimony of any expert economist.[32] They provide almost no detail about how the Board would actually implement the proposal. They are not accompanied by any analysis of the consequences or impacts on the railroad industry of the proposal, such as their impact on productivity, infrastructure needs, or the incentives to invest and improve efficiency. And they provide no evidence that the proposed measures would have positive public policy effects overall.

[30] NS Opening Comments, V.S. Sappington at 4 (emphasis added).

[31] That commenter is AECC, whose proposal for rate-of-return regulation is addressed below.

[32] For example, the Joint Coal Shippers produce no expert testimony in support of their proposed "rate freeze," and instead present only a statement by Harvey Levine proposing alternative methods for measuring revenue adequacy. The Concerned Shipper Associations' witness Gerald Faulhaber dedicates his testimony to criticism of the SAC test. AECC proposes a widespread restructuring of the regulatory regime without providing any expert testimony at all.

After repeated calls for a proceeding on this issue and ample time to develop opening evidence, shipper-commenters' inability to articulate any economically-sound proposals that would not have serious adverse consequences for the rail system is confirmation that an independent revenue adequacy constraint is fundamentally unworkable. *See* Norfolk Southern Opening Comments at 51-71 (describing problems with top-down independent revenue adequacy constraint). Neither the AECC proposal for a rate-of-return-based earnings cap nor the Olin proposal for a systemwide R/VC cap nor the Concerned Coal Shippers proposal for a "rate freeze" for revenue adequate railroads are workable, wise, supported by economics, or consistent with the Board's statutory obligations to promote revenue adequacy, to allow competition and the demand for services to establish reasonable rates whenever possible, and to minimize the need for federal regulatory control over the rail transportation system. *See* 49 U.S.C. § 10101(1-3).

A. The Board Should Reject AECC's and Olin's Proposal for a Return to Antiquated Rate of Return Regulation.

Both AECC and Olin offer proposals designed to limit railroad overall earnings, and those proposals are precisely the type of regulation being abandoned by regulators across the globe. AECC opens its comments by claiming that it is now time for the Board to return to "a more traditional role" of limiting railroad earnings to a "market rate of return." AECC Opening Comments at 2. While AECC makes a series of ill-founded proposals (including proposals to distort current rate case methodologies to make it easier for shippers to prevail), the centerpiece of its proposal is a rate-of-return style cap on earnings. AECC would declare any railroad earnings over the cost of capital to be "supracompetitive" and proposes that the Board automatically return a set percentage of rail revenues on traffic with R/VCs over 180% to those shippers. AECC Opening Comments at 22-23.

Olin's suggestion for an "R/VC Ceiling" is of a piece with AECC's proposal. *See* Olin Corp. Opening Comments at 7-9. Both propose systemwide earnings caps that would indiscriminately allocate allegedly excessive railroad earnings to shippers. The primary difference is that Olin's proposal would funnel more railroad earnings to shippers with relatively higher R/VC ratios (*i.e.,* chemical shippers like Olin), while AECC's would give equal shares to all traffic over 180% R/VC (which would give coal shippers like AECC a relatively larger share of the pie).

In the first place, AECC's and Olin's declaration that rail earnings are "supracompetitive" is predicated on an uncritical acceptance of annual revenue adequacy calculations that fail to properly measure railroad investment based on replacement costs. *See supra* at 7-9. If rail investment were accurately measured using replacement costs, these supposed "supracompetitive" earnings would evaporate.

More fundamentally, AECC and Olin completely ignore the multiple serious flaws with traditional rate-of-return style regulation that Norfolk Southern detailed in its opening comments. <u>First</u>, these proposals would transform the <u>minimum</u> rate of return that a railroad must attain to obtain adequate investment into a <u>maximum</u> cap on revenues.[33] The cost of capital represents "[t]he minimum rate of return that will allow railroads to obtain investment funds."[34] Preventing railroads from ever exceeding that minimum

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[33] *See* NS Opening Comments at 62-63; *see also id.*, V.S. Cornell at 25 ("if a railroad is required to adjust rates whenever it is deemed to be revenue adequate for one year, the railroad will never be able to produce long run returns that meet its cost of capital").

[34] *Standards I*, 364 I.C.C. at 810.

rate of return would doom railroads to permanent long-term revenue inadequacy, for if railroads are never permitted to earn more than their cost of capital in any year, they will never offset the years in which they earn less.

Second, a system-wide rate of return cap discourages rail carriers from pursuing innovation, investment, and productivity enhancements. What motivation does a railroad have to improve its efficiency and productivity if every dollar gained must be immediately returned to shippers? *See* NS Opening Comments at 59-62. As Professor Sappington explained, the kind of stringent profit regulation that AECC advocates significantly reduces incentives for companies to reduce operating costs. *See id.*, V.S. Sappington at 8-9. Professor Cornell similarly showed that such a rate constraint "would dampen the incentive for railroads to take these kinds of innovative risks to improve service." *Id.*, V.S. Cornell at 35. AECC and Olin do not even acknowledge the negative incentives that its proposal would create, let alone show that they could be mitigated.

Third, AECC's claim that every shipper whose traffic moved at rates above 180% R/VC should be entitled to a share of the allegedly excessive profits of a railroad earning more than its cost of capital (and Olin's claim that every R/VC ratio over a certain level should be capped) ignore that there is no correlation between *system-wide* revenue adequacy and the reasonableness of an individual rate.[35] Indeed, these proposed revenue adequacy constraints would create impermissible internal cross-subsidies by allowing railroad earnings to be reallocated to all rail shippers with traffic over 180% R/VC—regardless of

[35] *See* NS Opening Comments at 68-69; *BNSF Ry. Co. v. STB*, 453 F.3d at 481 (holding that because RSAM only measures "system-wide revenue need," it provided "no guidance" as to the individualized rate that the complainant should pay for the facilities and services it used).

whether those shippers' rates are in fact more than necessary to cover that shippers' attributable costs.[36]

Fourth, AECC's proposal would arbitrarily allocate supposedly "supracompetitive" earnings in a way that would discourage negotiated contracts. Because the Board lacks jurisdiction over transportation contracts, shippers whose traffic moved under contract would be ineligible for the earnings windfall that AECC wants the Board to give to non-contract shippers.[37] *See* 49 U.S.C. § 10709(c)(1). A regulatory regime that made tariff shippers eligible for windfall "rebates" whenever a railroad happened to become revenue adequate--but that provided no such rebates to contract shippers—would create strong incentives for shippers to refuse to enter into contracts to preserve their eligibility for a potential windfall payment. Such a result is utterly inconsistent both with the Board's policies of encouraging negotiations and voluntary agreements and with its statutory mandate "to minimize the need for Federal regulatory control over the rail transportation system." 49 U.S.C. § 10101(2).

B. The Board Should Reject Any Proposal to Impose a "Rate Freeze" On Railroads Found to Be Revenue Adequate.

The Joint Coal Shippers propose an alternative revenue adequacy constraint that would limit the ability of a revenue adequate railroad to increase its rates. *See* Joint Coal Shipper Opening Comments at 26-33; *see also* ARC Opening Comments at 22 (proposing similar rate freeze). While this proposal does not constitute traditional rate of return regulation (in that it is not designed

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[36] *See* NS Opening Comments at 66-68; *PPL Montana, LLC v. BNSF Ry. Co.*, 6 S.T.B. 752, 757 (2003) (holding that rule against cross-subsidization "is not limited to the SAC test").

[37] AECC's suggestion that contract shippers could nevertheless receive a share of revenue through a "carry-forward" would be blatantly illegal under 49 U.S.C. § 10709(c)(1), which precludes shippers from claiming that any provision of a transportation contract (including the agreed-upon rate) violates the Interstate Commerce Act.

to constrain overall returns or return "excess" revenues to shippers), this kind of rate freeze and aggressive intervention into the marketplace has numerous fundamental problems.

First, a basic problem with any rate freeze is that markets are dynamic and constantly changing over time. The Joint Coal Shippers ask the Board to presume that any rate increase by a revenue adequate railroad is an inappropriate exercise of market power, but that is not true. For example, a railroad might increase a particular rate because increasing demand is tightening capacity in the surface freight transportation marketplace. Indeed, a recent J.B. Hunt white paper on industry challenges in the trucking industry discusses significant strains on trucking capacity due to driver shortages, hours of service regulations, and increased demand.[38] Trucks and railroads often compete in the surface transportation market, and reduced capacity for trucks affects the demand for rail transportation.

A well-functioning marketplace is supposed to respond to a surge in demand by increasing the price. This sends a signal to the marketplace that the price for scarce transportation, including scarce rail capacity, is increasing, and it also facilitates the proper allocation of resources by railroads and shippers. Alternatively, a need to fund capital improvements on a particular line might justify increasing rates for the shippers that use that line. The basic theory of differential pricing is that prices should be responsive to individual demand. Indeed, Congress has instructed the Board "to allow, to the maximum extent possible, competition and the demand for services to establish reasonable rates for transportation by rail." 49 U.S.C. § 10101(1). A rate freeze, however, caps prices at one point in time and does not allow for price adjustments based on any

[38] *See* J.B. Hunt, *Industry Challenges*, *available at* http://blog.jbhunt.com/wp-content/themes/files/pdf/IndustryChallenges.pdf (Attachment C).

subsequent changes in the customer's demand. A heavy-handed rate freeze will prevent the marketplace from functioning properly.

Second, a rate freeze would effectively force the Board to select winners and losers among the shipping public. Certain shippers with stable, long-term commodity flows would have their rates "locked in." But new shippers would not have those benefits. Nor would shippers with shifting movement patterns due to more fluid networks of customers or suppliers. A rate freeze thus would be arbitrary and effectively would cross-subsidize stable legacy shippers at the expense of newer shippers or shippers with less stable movement patterns.[39]

Third, a rate freeze would discourage private contracts, in contravention of the statute. *See* 49 U.S.C. § 10101(1-2). For if a rail rate is "locked in" after expiration of a contract, both railroads and shippers will have substantial disincentives to a contract agreement. Railroads will not want to offer lower rates in exchange for a contractual volume commitment, for fear that that rate will be locked in indefinitely even after the contract and its volume commitment expires. Shippers similarly will not want to agree to higher contract rates in exchange for railroad service commitments, for such a commitment would effectively increase the potential tariff rate after expiration of that contract and service commitment. The Board should be extremely cautious to not make regulatory changes that could discourage transportation contracts and negotiated solutions. The Board has a statutory obligation "to minimize the need for Federal regulatory control over the rail transportation system" and "to allow, to the maximum extent possible, competition and the demand for services to establish reasonable rates for transportation by rail," which contracts do. 49 U.S.C. § 10101(1-2). Those goals are utterly inconsistent with a regulatory change

[39] Not coincidentally, the "winners" under the Joint Coal Shippers' proposal would include large electric utilities with stable movement patterns.

that would discourage parties from committing to contract rates that would be locked in by Board regulations indefinitely.

Fourth, a rate freeze would discourage many productivity and service improvements. What incentive would a railroad have for service improvements that increased shipment speed (and thus increased the value of the railroad's service offering), if it were prohibited from increasing its rates to account for that enhanced service value? *See* NS Opening Comments, V.S. Sappington at 8-9. The Joint Coal Shippers' single-minded focus on securing lower rates by any means necessary ignores the significant adverse effects that their proposal would have on incentives to improve customer service.

While the Joint Coal Shippers claim that railroads would have some opportunity to justify a rate increase, the test they propose makes this an illusory promise. *See* Joint Coal Shippers Opening Comments at 32-33. Under their proposal a railroad could only justify a rate increase greater than RCAF if it proved by "clear and convincing evidence" that it had "a need for higher revenues," "specific harm that would result if it could not collect them," and "inability to raise them from any source other than captive traffic." *Id.* at 32. Indeed, the Joint Coal Shippers emphasize that railroads should face a "particularly high" burden and should "rarely" prevail. *Id.* And they propose to limit the railroad's presentation in ways that preclude evidence of critically important factors. For example, the Joint Coal Shippers proposal leaves no room for a railroad to present evidence that it is not in fact revenue adequate under proper measurements and replacement costs.[40] It would not allow the railroad to submit alternate evidence that a rate increase is reasonable because of demand

[40] *Id.* at 32-33 (arguing that railroad could only prevail if it submitted "detailed and particularized evidence demonstrating each of the three (3) separate criteria" [*i.e.*, a need for higher revenues, specific harm from not collecting such revenues, and an inability to raise such revenues from other sources]).

shifts, because the shipper is located on a light density line, or because serving the shipper requires particularly expensive facilities or operations. Nor could a railroad submit evidence that the commodity being carried is extremely dangerous and merits a relatively higher rate increase than other traffic. These significant limitations make it all but certain that the Joint Coal Shippers' proposal would result in across-the-board rate caps for nearly every rate.

As a result, the Joint Coal Shippers proposal is fundamentally inconsistent with the agency's longstanding policy that overall revenue adequacy is irrelevant to the question of whether an individual rate is reasonable.[41] This principle has often worked to the benefit of shippers by recognizing that rates could be unreasonable even if a railroad remained revenue inadequate systemwide. Even if a railroad is revenue inadequate overall, it is possible that there are particular parts of the railroad's network where the railroad nonetheless is charging the shipper unreasonable rates that cross-subsidize other parts of the network. SAC and Simplified SAC will detect those unreasonable rates and protect shippers in those locations.

Similarly, if a railroad is revenue adequate (properly measured), it is possible (and indeed likely) that on some parts of its network shippers are not covering the costs attributable to serving them. Allowing those shippers to nevertheless receive "revenue adequacy" relief would impermissibly cross-subsidize that traffic.[42] On a revenue adequate railroad, the SAC and SSAC tests will detect and protect those shippers who are paying more than is necessary for

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[41] *See Omaha Public Power Dist. v. Burlington No. R.R. Co.*, 3 I.C.C.2d 123, 157 (1986) ("a finding of revenue inadequacy does not give a railroad license to set rates at unreasonable levels"); *BNSF Ry. Co. v. STB*, 453 F.3d at 481 (RSAM measure of "system-wide revenue need" will "provide[] no guidance on the rates Xcel should be charged for the particular facilities and services Xcel uses").

[42] *See PPL Montana, LLC v. BNSF Ry. Co.*, 6 S.T.B. at 757 ("CMP principle against cross-subsidization is not limited to the SAC test").

the railroad to be revenue adequate on that segment of the network. There is no need to add an independent, undifferentiated revenue adequacy constraint—particularly when such a constraint would have significant negative consequences for railroad investment and productivity.

III. SHIPPERS HAVE AMPLE ABILITY TO CONTEST THE REASONABLENESS OF RATES UNDER EXISTING RATE REASONABLENESS REMEDIES.

Some of the opening commenters also claim that an independent revenue adequacy constraint is necessary because of supposed shortcomings in the Board's existing rate remedies. For example, shippers claim that SAC is "not affordable,"[43] is "ineffective,"[44] and is "not a viable option[] for the majority of captive shippers."[45] The Concerned Shipper Associations in particular assert that "although SAC is the only current standard for determining the reasonableness of rail rates, the increasing cost, complexity, and expense of bringing a SAC case *itself* should influence the Board to develop a clearer, shorter, and less expensive standard." Concerned Shipper Associations Opening Comments at 7 (emphasis in original).

These complaints about the Board's existing rate reasonableness remedies range from the plainly exaggerated to the manifestly incorrect. The Concerned

[43] ARC Opening Comments at 3-4 ("The SAC, Simplified SAC and Three-Benchmark tests are not affordable and do not work for the overwhelming majority of captive shippers who may need a defense against abuses of railroad market power.").

[44] Olin Corp. Opening Comments at 7 ("the SAC constraint is an ineffective remedy for shippers").

[45] ARC Opening Comments at 13 ("We do not believe, however, that SAC or SSAC are today, or will ever be, viable options for the majority of captive shippers."); *see also* AECC Opening Comments at 18-20 (requesting simplified rate methods following achievement of revenue adequacy); Concerned Shipper Associations Opening Comments at 3 ("the Board's well-established Stand-Alone Cost ("SAC") constraint upon rail rates has not been an effective, practical, or economic process for challenging the reasonableness of exceedingly high, and rapidly increasing, rail rates"); Olin Corp. Opening Comments at 7-8 ("the Board should focus its efforts on creating a simpler and more efficient procedure for reviewing rate cases");

Shipper Associations fall squarely into the manifestly incorrect category, with their obviously erroneous claim that "SAC is the only current standard for determining the reasonableness of rail rates." *Id.* at 7. On the contrary, SAC is just one of three independent methodologies developed by the Board, two of which were specifically designed for use by shippers in search of a lower-cost alternative to a full-SAC analysis. *See Simplified Standards for Rail Rate Cases*, Ex Parte 646 (Sub-No. 1). Commenters claiming that a revenue adequacy constraint is essential to serve as an alternative to full-SAC analyses ignore the fact that shippers already have access to low-cost alternatives that do not pose the same kind of fundamental problems inherent in an independent revenue adequacy constraint.

Shipper commenters complain that the Board's existing rate remedies are theoretically flawed; that SAC cases are too expensive to litigate; that shippers lack the operational knowledge to develop SAC cases; that rate cases are too hard for shippers to win; and that the statutory rules for rate cases are not to shippers' liking. None of these claims has any merit, and none can justify adding an inherently flawed revenue adequacy constraint to the Board's existing suite of proven rate reasonableness remedies.

A. SAC Is An Economically Valid, Judicially Affirmed Methodology That Has Stood The Test of Time.

The Concerned Shipper Associations launch an attack on the theoretical underpinnings of SAC itself, relying on a Verified Statement by Gerald Faulhaber. Professor Faulhaber's criticisms are addressed in detail by Professor Robert Willig in a Verified Statement being filed with the Reply Comments of the Association of American Railroads. Norfolk Southern incorporates and relies on Professor Willig's statement here. Norfolk Southern also notes that Professor Faulhaber appears to have a limited understanding of how the Board's full suite of rate reasonableness processes operates.[46] For example, he criticizes the Board for not developing a "model" that could be used as a substitute for SAC and points to the Uniform Rail Costing System ("URCS") as a good example of a successful model. V.S. Faulhaber at 10. But of course that is precisely what Simplified SAC is: an URCS-based model of operating costs that a shipper can choose to use in place of a Full-SAC presentation. Simplified SAC is the sort of "standard stand-alone cost model" that Professor Faulhaber criticizes the Board for supposedly not adopting. *Id.* at 11-12.

Moreover, the Concerned Shipper Associations' criticisms ignore the fact that the SAC test is founded in "sophisticated economic theories"[47] and has been repeatedly approved as an economically valid methodology.[48] Attacks on the foundations and reliability of the SAC test are unsupported, contrary to the academic literature, and contrary to the long line of Board and court decisions affirming its economic foundation.[49] At its inception, SAC was supported by

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[46] Professor Faulhaber's discussion of SAC cases is peculiarly phrased in referring to the Board's "turning down" such cases, when in fact they were decided on their merits adversely to the complaining shippers. *See* V.S. Faulhaber at 9-10. He also appears confused about *SunBelt Chlor Alkali Partnership v. Norfolk Southern*, which he claims was decided in 2010 (even though it was actually decided in 2014 and still has pending petitions for reconsideration). *See id.* at 10.

[47] *Coal Rate Guidelines*, 1 I.C.C.2d at 525.

[48] *See SunBelt Chlor Alkali P'ship v. Norfolk S. Ry. Co.*, STB Docket No. NOR 42130, at 30 (served June 20, 2014) (Elliot, C., concurring) (acknowledging that SAC is "economically sound" and "advance[s] the goals" of ICCTA) ("*SunBelt*"); *Simplified Standards for Rail Rate Cases*, STB Ex Parte No. 646 (Sub-No. 1) at 13 (served Sept. 5, 2007) ("*Simplified Standards*"); *Burlington N. R.R. Co. v. Interstate Commerce Comm'n*, 985 F.2d 589, 596 (D.C. Cir. 1993).

[49] As the ICC, the Board, and the Courts have repeatedly affirmed, CMP—and the Stand-Alone Cost constraint in particular—is the best and most accurate methodology for evaluating the reasonableness of common carrier rail rates. *See, e.g., Burlington Northern R.R. Co. v. Interstate Commerce Comm'n*, 985 at 596 (("CMP, with its SAC constraint is the 'preferred and most accurate procedure available for determining the reasonableness' of rates in markets where the rail carrier enjoys market dominance.") (quoting ICC in *McCarty Farms v. Burlington Northern, Inc.*, 3 I.C.C. 2d 822 (1987)); *Simplified Standards* at 13 ("CMP, with its SAC constraint, is the most accurate procedure available for determining the reasonableness of rail rates where there is an absence of effective competition.").

dozens of leading economists of the day. Those economists submitted a joint statement of basic principles to guide the ICC in its rate setting duties, which strongly supported SAC as an economically valid measure.[50] Since that time, academic literature has continued to support the SAC test.[51] The Board has no basis to question the validity of a long-settled methodology that has been repeatedly approved by the courts and accepted as an economically sound basis for adjudicating the reasonableness of rates.

B. Shippers Complain that SAC is Too Costly, But Fail to Acknowledge the Simplified Procedures Available to Them.

Some commenters also complain that SAC analyses are too expensive.[52] It is true that challenging rail rates under the full-SAC methodology requires a rigorous and complex investigation. But it is also true that <u>all</u> litigation can be expensive and complex, particularly when significant amounts of money are at stake. Given the amount of money at stake in many SAC cases, it is not surprising or unwarranted that litigating those cases is a complex endeavor.

Claims that SAC cases are expensive ignore the fact that shippers already have two alternatives to SAC that each have significantly lower litigation costs than a full-SAC case.[53] Both Simplified SAC and the Three-Benchmark test are

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[50] Economists' Statement in Support of Staggers Act (Feb. 25, 1985) (Attachment D).

[51] *See, e.g.,* Baumol, William J., John C. Panzar, and Robert D. Willig, *Contestable Markets and the Theory of Industry Structure*. New York: Harcourt Brace Jovanovich, Inc., 1982; Hausman, Jerry and Stewart Myers, "Regulating the United States Railroads: The Effects of Sunk Costs and Asymmetric Risk," *Journal of Regulatory Economics*, 22(3), November 2002, 287-310; John W. Mayo, Mark Burton, David Kaserman, "Common Costs and Cross-Subsidies: Misestimation Versus Misallocation," *Contemporary Economic Policy* (2009).

[52] *See* ARC Opening Comments at 13; Olin Corp. Opening Comments at 5.

[53] *See Simplified Standards*, at 92-93 (estimating cost of a Simplified SAC case to be $969,988 and cost of a Three Benchmark case to be $191,500). The Board's revised estimate of Simplified SAC costs in *Rate Regulation Reforms*, Ex Parte 715, was remanded by the D.C. Circuit because of a double-counting error in the Board's calculations. *CSX Transp., Inc. v. STB*, 754 F.3d 1056, 1065-66 (D.C. Cir. 2014).

real, viable alternatives for shippers who wish to challenge the reasonableness of their rates but who believe that SAC is too complex or expensive.[54] And even SAC cases are less expensive as a result of the Board's efforts. [55] Moreover, the Board's decisions and recent rulemakings have clarified or resolved an increasing number of issues, ranging from the methodology for revenue allocation[56] to guidance for constructing a SARR for a traffic group consisting primarily of carload traffic.[57] Recent SAC complainants have recognized that the Board's decisions have "produced a well-defined body of precedent that can be relied upon by parties in SAC cases to design a specific SARR."[58] As a result, the Board's rate reasonableness procedures are as transparent and accessible as they have ever been.

The Board's recent actions to make its simplified procedures available to all shippers, to remove the limitation on relief from SSAC cases, and to lower the filing fee for full-SAC challenges make rate reasonableness remedies more accessible to shippers than ever before. Continued complaints that rate cases are

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[54] Norfolk Southern continues to believe that the Board should impose a reasonable limit on relief for both Simplified SAC cases and Three Benchmark cases, because those methodologies are less economically sound than SAC.

[55] Perhaps the most significant recent simplification is the Board's removal of movement-specific adjustments to URCS, a change that the Board estimated could save as much as $1 million in litigation costs per case. *See Major Issues in Rail Rate Cases*, STB Ex Parte No. 657 (Sub-No. 1) (2006). The Board has also lowered filing fees for a SAC case from over $180,000 to just $350 dollars. *See* Consolidated Appropriations Act of 2008, Pub. L. No. 110-161, Division K, Sec. 194; *Regulations Governing Fee for Services*, Docket No. EP 542 (Sub-No. 18), at 2 (Feb. 14, 2011); 49 C.F.R. § 1002.2(f).

[56] *See Rate Regulation Reforms*, Ex Parte No. 715, at 30 (served July 18, 2013).

[57] *See, e.g.*, *SunBelt*, STB Docket No. 42130,at 16 & n.66 (June 18, 2014).

[58] Opening Evidence of SunBelt , *SunBelt*, STB Docket No. 42130, at I-40 (filed Aug. 1, 2012); *see* Opening Evidence of E.I. du Pont de Nemours & Co., *DuPont*, STB Docket No. 42125, at I-54 (filed Apr. 30, 2012) ("the Board has developed an increasingly well-defined set of precedent that has established consistent principles for deciding a number of . . . key issues dealing with the overall design of the SARR").

too expensive are not persuasive and cannot justify adoption of a fatally flawed independent revenue adequacy constraint.

C. Complaints That Railroads Have Superior Knowledge Of Rail Operations Are Irrelevant and Contradict Shippers' Own Statements In SAC Cases.

Some commenters also complain that shippers are at a disadvantage in SAC cases "because they do not have the railroad's experience and expertise in rail operations."[59] But the issue is not the shipper's expertise; it is the expertise of shipper consultants and witnesses. Shippers have access to experienced counsel and consultants who have litigated and won multiple SAC cases and developed multiple operating plans. Indeed, in a recent case Olin's affiliate SunBelt touted its rail operations experts as some "of the nation's leading rail operations and management experts."[60] Just like the railroads, shippers hire experts to prepare SAC evidence. Those experts have years of experience in the railroad industry and have extensive experience with the SAC analysis itself.[61] Shippers have ample tools available to litigate SAC cases effectively.

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[59] Concerned Shippers Opening Comments at 6; Olin Corp. Opening Comments at 7.

[60] *See* Opening Evidence of SunBelt, *SunBelt*, STB Docket No. 42130, at III-C-1 (filed Aug. 1, 2012); *see also* SunBelt Rebuttal at III-C-13-14 (filed June 3, 2013) ("SunBelt's Operating Plan was Prepared by Experts With Many Years of Railroad Operating Experience"); *id.* at 14 (touting witnesses as "eminently qualified to run simulation in the RTC model, and, in fact, were responsible for the RTC simulation in the *Otter Tail* case, which was the first SAC case in which a shipper's operating plan was accepted by the STB."); Rebuttal Evidence of DuPont, *DuPont*, STB Docket No. 42125, at III-C-13 (filed April 13, 2013) (operating witness "is intimately familiar with the operating requirements of carload railroads"); *id.* at 14 (operating witnesses "are eminently qualified to run simulations in the RTC model").

[61] *See, e.g.*, Opening Evidence of DuPont , *DuPont*, STB Docket No. 42125, at IV-46 (filed Apr. 30, 2012) (citing shipper witness's experience "in numerous stand-alone cost proceedings"); *id.* at IV-53 (touting shipper witness's experience with "stand-alone cost procedures in numerous rail rate cases"); *id.* at IV-59 (citing shipper witness's experience with "the development of stand-alone cost evidence presented to the ICC and the Board in numerous cases"); *id.* at IV-67 (touting shipper witness's experience "present[ing] evidence applying the STB's stand-alone cost procedures in a number of rail proceedings before the STB").

D. Shippers' Complaints About Losing SAC Cases Are Irrelevant.

Some commenters also complain that shippers have lost some recent rate cases.[62] That is true.[63] Shippers have also won several recent rate cases.[64] More importantly, wins and losses are irrelevant to whether or not the Board's rate processes are effective. All parties benefit when the regulator has a clearly understood, economically sound methodology that can form a background for negotiations and assessments of what rates are likely to be found reasonable.

Nevertheless, some commenters suggest that SAC must be ineffective for carload shippers because shippers have not prevailed in particular rate cases.[65] The fact that DuPont failed to demonstrate that Norfolk Southern's rates were unreasonable does not show inherent flaws in the SAC test. On the contrary, the SAC test proved to be a workable framework for deciding even a novel and complex case involving well over 100 challenged rates. DuPont lost not because SAC is flawed but rather because the challenged rates were in fact reasonable. DuPont nevertheless chose to roll the dice by taking extreme litigation positions in an effort to artificially lower the SARR's costs. The Board rightly rejected these extreme positions.[66]

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[62] *See* Concerned Shipper Associations Opening Comments at 6-7;

[63] Specifically, the Board found earlier this year that neither DuPont nor SunBelt had demonstrated that challenged Norfolk Southern rates were unreasonable under the SAC test.

[64] *See, e.g.*, *Arizona Elec. Power Coop. v. BNSF Ry. Co. & Union Pac. R.R. Co.*, STB Docket No. 42113 (Nov. 22, 2011); *U.S. Magnesium v. Union Pacific R.R. Co.*, STB Docket No. 42116 (Apr. 2, 2010). Moreover, negotiated settlements of rate complaints should also be recognized as successful outcomes for complainants and for the regulatory regime as a whole. In recent years, rate complaints brought by Intermountain Power Association, M&G Polymers USA, Canexus, South Mississippi Electric Power Association, Seminole Electric, and NRG Energy have all been successfully settled.

[65] *See* Olin Corp. Opening Comments at 6-7 (suggesting that DuPont's failure to prevail in its rate case is reason for the Board to develop an alternative to SAC).

[66] *See, e.g., DuPont*, STB Docket No. 42125, at 39 (rejecting DuPont's operating plan in part for failure to account for all of the trains necessary to serve the issue traffic); *id.* at 41-42 (rejecting operating plan in part for failure to posit any blocking or classification of traffic at intermediate yards); *id.* at 148-49 (rejecting DuPont's attempt to rely upon the

In short, shippers' claims that the SAC test is ineffective because shippers cannot be guaranteed to win are not credible. Any litigation involves risk, and SAC cases are no different. Shippers are not entitled to a rate regulatory regime in which complainants are guaranteed victory if they choose to challenge a rate. In fact, as the Board has continued to clarify issues in rate cases railroads have a better ability to understand what rates will be deemed to exceed a reasonable maximum. As railroads work to conform their pricing accordingly, one would expect both that fewer rate cases would be filed and that railroads would prevail in many of those cases.

E. Many of Shippers' Complaints Are About Statutory Requirements That the Board Cannot Alter.

Shippers' remaining complaints about the existing rate regime boil down to complaints about the statutory requirements Congress has imposed on the Board. For example, shippers complain that they are required to pay challenged rail rates until those rates are deemed unreasonable by the Board.[67] But that rule is mandated by the Interstate Commerce Act, which gives railroads the right to set rates and provides that those rates may not be set aside unless the Board finds them to be unreasonable.[68] That basic statutory rule will apply regardless of what rate methodology is used. And critically, if a complainant is successful in challenging a rate, any amounts above a reasonable level must be repaid to the shipper with interest. Indeed, the Board recently increased the interest rate for reparation awards.[69]

1.3 mile Trestle Hollow rail line relocation project as "representative of the costs the DRR would incur in constructing a 7,300 mile, multi-state railroad.").

[67] Concerned Shipper Association Opening Comments at 7; Olin Corp. Opening Comments at 5; ARC Opening Comments at 22.

[68] *See* 49 U.S.C. §§ 10702, § 10704; *Seminole Elec. Coop., Inc. v. CSX Transp., Inc.*, STB Docket No. 42110, at 3 (served Dec. 18, 2008).

[69] *See Rate Regulation Reforms* at 35-36 (adopting the U.S. Prime Rate as the interest rate for reparations).

In another example of complaining about Congress's commands, ARC suggests that the Board "shift [the] evidentiary burdens to the railroads" and require that the railroads justify rate increases.[70] ARC's proposal is clearly at odds with the statutory principle that the complainant, as the party seeking relief, has the burden of proving that a challenged rate is unreasonable.[71] ARC's reasoning for this proposal—that railroads have greater resources and much of the relevant data—ignores the Board's broad discovery rules that permit shippers to seek almost unlimited discovery of any relevant data from the railroads.[72] Congress imposed the burden of proving its case on complainants—just as <u>any</u> plaintiff to <u>any</u> litigation would have to prove its case in court. The Board is not free to shift that burden to the defendant railroads.

ARC also complains that establishing market dominance is too difficult.[73] But establishing market dominance is a statutory requirement that cannot be ignored.[74] Indeed, the basic purpose of market dominance is that the agency is only permitted to regulate rates that are not already being constrained by competitive forces.[75] Absent a showing of an abuse of market power, Congress has determined that market forces will protect shippers.[76]

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[70] ARC Opening Comments at 22.

[71] 49 U.S.C. § 10701; 5 U.S.C. § 556(d); s*ee, e.g., Duke Energy Corp. v. Norfolk S. Ry. Co.*, 7 S.T.B. 89, 100 (2003) ("[T]he party with the burden of proof—i.e., the shipper on SAC issues—must present its full case-in-chief in its opening evidence."); *Coal Rate Guidelines*, 1 I.C.C.2d at 547; *Minnesota Power Inc. v. DM&IR*, STB Docket No. 42038 at 7 (Mar. 3, 2000) ("a complainant bears the burden of proof").

[72] *See* 49 C.F.R. Part 1114.

[73] ARC Opening Comments at 31.

[74] *See* 49 U.S.C. § 10707(b).

[75] H.R. CONF. REP. NO. 96-1430, at 105 (1980), *reprinted in* 1980 U.S.C.C.A.N. 4110, 4137 (Congress "expects" that "the Commission will adopt a policy of reviewing carrier actions after the fact <u>to correct abuses of market power</u>") (emphasis added).

[76] *See id.* at 89 (agency should "allow[] the forces of the marketplace to regulate railroad rates wherever possible").

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In short, the Board's processes for affording shippers rate relief are more than sufficient. The Board's settled methodologies for rate reasonableness are accessible to shippers, founded on the sound economics of the SAC test, and well understood by all stakeholders. There is no need to add yet another rate reasonableness methodology, and particularly one with the inherent flaws of an independent revenue adequacy constraint.

IV. THE BOARD SHOULD DISREGARD CALLS TO ADOPT RATE POLICIES THAT WOULD HINDER THE PRESSING NEED FOR RAIL INVESTMENT.

Norfolk Southern concludes by reminding the Board that the Nation is in dire need of more railroad investment. Shippers and government officials continue to call for railroads to improve service and increase capacity. These necessary actions require investment dollars, which must come almost exclusively from private railroad funding, not taxpayer dollars. The Nation needs the railroads to continue to invest in their networks, not only to improve rail service, but simply to maintain the current level of service provided. The Board should be extremely cautious not to take any actions that could discourage this critically needed investment.

A. All Stakeholders In the Rail Transportation Network Recognize the Pressing Need for Capital Investment To Improve Capacity.

Railroads continue to face new challenges that require enormous investment. Billions of dollars in railroad investment will be required to address capacity issues and improve service. Over the next 25 years, it is projected that freight rail traffic will increase anywhere from 65% to 93% from mid-2000 levels.[77] While railroads are engaged in unprecedented levels of capital

[77] USDA & DOT, *Study of Rural Transportation Issues*, at 335 (Apr. 2010) (projecting a 65% increase in domestic freight demand from 1998 to 2020); American Association of State Highway and Transportation Officials ("AASHTO"), *Freight Rail Bottom Line Report*, at 50 (2003) (projecting freight increase from 15.2 billion tons in 2000 to 24.5 billion tons in

investment, some fear that current spending levels may not be sufficient to keep up with increasing capacity demands over the next 25 years.[78] Such investments simply will not be possible absent a strong regulatory framework that encourages rail investment and promotes financial stability.

The federal government has recognized the pressing need to improve and expand railroad infrastructure to deal with the impacts of increasing traffic volume. In a 2008 report, GAO reported that congestion was attributable at least in part to railroad infrastructure including "[s]ome railroad corridors between major markets [that] do not have double tracked right-of-ways; adequate passing areas, intermodal yards, or switching facilities; or bridges or tunnels that can simultaneously accommodate multiple trains on different routes."[79] The Board itself has recognized that "[r]ailroads no longer are burdened by substantial excess capacity; rather, the rail industry now faces the opposite situation. Rail capacity is strained, demand for transportation service is forecast to increase, and railroads must make capital investments to meet that demand."[80] Congestion caused by lack of capacity at even a few key locations can have widespread impacts on service levels across the rail network.

Many shippers also recognize the need for capital investment and capacity improvement. This sentiment was particularly strong at recent Board hearings

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2020); Federal Highway Administration, *FAF2 the Second Generation of the Freight Analysis Framework* (July 2007) (projecting that total freight transportation could rise by 93% from 2007 levels by 2035).

[78] According to AASHTO's 2003 rail study, to maintain modal share from 2000, the industry would need to invest $175 to $195 billion, with approximately $3.5 billion devoted to infrastructure improvements above and beyond repair and maintenance on a yearly basis. This estimate reflects a gap of $2.65 billion per year above current private railroad reinvestment. AASHTO, *Freight Rail Bottom Line Report* at 4.

[79] U.S. GOV'T ACCOUNTABILITY OFFICE, FREIGHT TRANSPORTATION: NATIONAL POLICY AND STRATEGIES CAN HELP IMPROVE FREIGHT MOBILITY 12-13 (Jan. 2008).

[80] *Simplified Standards* at 14.

regarding rail service issues. Shippers have testified that the chemicals and agricultural industries are experiencing significant growth in rail volumes.[81] These shippers have called upon railroads to invest in rail infrastructure to expand capacity and meet growing demands.[82] For example, State Senator for North Dakota, George Sinner, called for railroads to make "long-term investments" necessary to expedite increased grain shipments. Testimony of North Dakota State Senator George Sinner, STB Public Hearing in Fargo, North Dakota, at 1:14:45 (Sept. 4, 2014).

Legislators have echoed these calls for railroad investment in capacity growth. At the Board's early-September hearing in Fargo, North Dakota, Senator John Hoeven noted that "strained track capacity [and] "growth in volume" were among some of the factors contributing to service concerns in the State.[83] A few days later, at the September 10th Senate Commerce, Science and Transportation Committee Hearing, Senator Hoeven again called upon the railroads to bring more resources to North Dakota, noting that "we need more capacity from the railroads" through more track, personnel, and infrastructure investment. The

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[81] *See* Comments of Alliance for Rail Competition, *United States Rail Service Issues*, STB Ex Parte 724, at 14 (filed Apr. 15, 2014) ("This growth in traffic and the associated necessary rail expansion will lead to continuing capacity issues for the next 5 to 10 years."); Testimony of ARC at 20 (filed Sept. 16, 2014) ("USDA recently announced that it expects corn growers will produce a record-high crop at 14.0 billion bushels of corn, up 1 percent from 2013 which was also a record at the time. USDA also expects a record soybean crop of 3.82 bushels in 2014, up 16 percent from last year.").

[82] *See* Public Hearing, Testimony of Hal Clemensen, South Dakota Wheat Growers Cooperative, *United States Rail Service Issues*, STB Ex Parte 724, at 369 (Apr. 10, 2014) ("We feel that there needs to be a lot more reinvestment in the rail system than what is being planned at this point."); *United States Rail Service Issues*, STB Ex Parte 724, Comments of Minnesota Grain and Feed Association at 2-3 (filed Apr. 10, 2014) ("Velocity and Cycle time of cars needs to obviously improve, which means that the railroads will need to put a lot of money into infrastructure improvements over the next few years."); Testimony of South Dakota Grain and Feed Association, Jerry Cope at 3 (filed Sept. 8, 2014) (encouraging railroads to make "investment decisions to increase capacity").

[83] Testimony of Senator John Hoeven, Ex Parte 724, at 1 (filed Sept. 4, 2014).

Senator went on to note that the railroads "need to bring the resources, which not only serves our shippers, but the railroads themselves."[84] Senator Heitkamp echoed this call, noting that "huge amounts of capital infusion is needed in order to solve" the capacity problems plaguing the railroads.[85] The Board must not act to stifle incentives for the investment that so many stakeholders recognize is essential.

B. Investment in the Rail Industry Requires Financial Certainty and A Stable Regulatory Framework.

Because so much of the rail industry's investment in infrastructure requires large and expensive projects that take years to pay off, such investments require economic stability—both in the form of volume certainty and revenue certainty.[86] Railroad investments are largely sunk, meaning that they are not easily repurposed or reassigned.[87] As a result, the risk for such investments is increased and projects are likely to be made "only if they are expected to be profitable."[88] To encourage these projects, certainty is required. Norfolk Southern Opening Comments at 69 ("It is fairly universally accepted that regulatory uncertainly deters investment.") Without such certainty, railroads may be more likely to invest in smaller projects that will mitigate immediate issues, but are less likely to produce long-term solutions to the larger issue at

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[84] *Id.*

[85] *Freight Rail Service: Improving the Performance of America's Rail System before the Senate Committee on Commerce, Science and Transportation*, 113 Cong. (Sept. 10, 2014) (Testimony of Senator Heitkamp).

[86] Senator Heitkamp testified to this fact at the recent Senate hearings on rail service issues. The Senator noted that railroads need to have certainty that the increase in traffic is not temporary to commit the huge amounts of funding necessary to improve capacity on the rail lines. *Freight Rail Service: Improving the Performance of America's Rail System before the Senate Committee on Commerce, Science and Transportation*, 113 Cong. (Sept. 10, 2014) (Testimony of Senator H. Heitkamp).

[87] Laurits R. Christensen Associates, Inc., *Supplemental Report to the U.S. Surface Transportation Board on Capacity and Infrastructure Investment,* at 2-18 (Mar. 2009).

[88] *Id.* at 2-19.

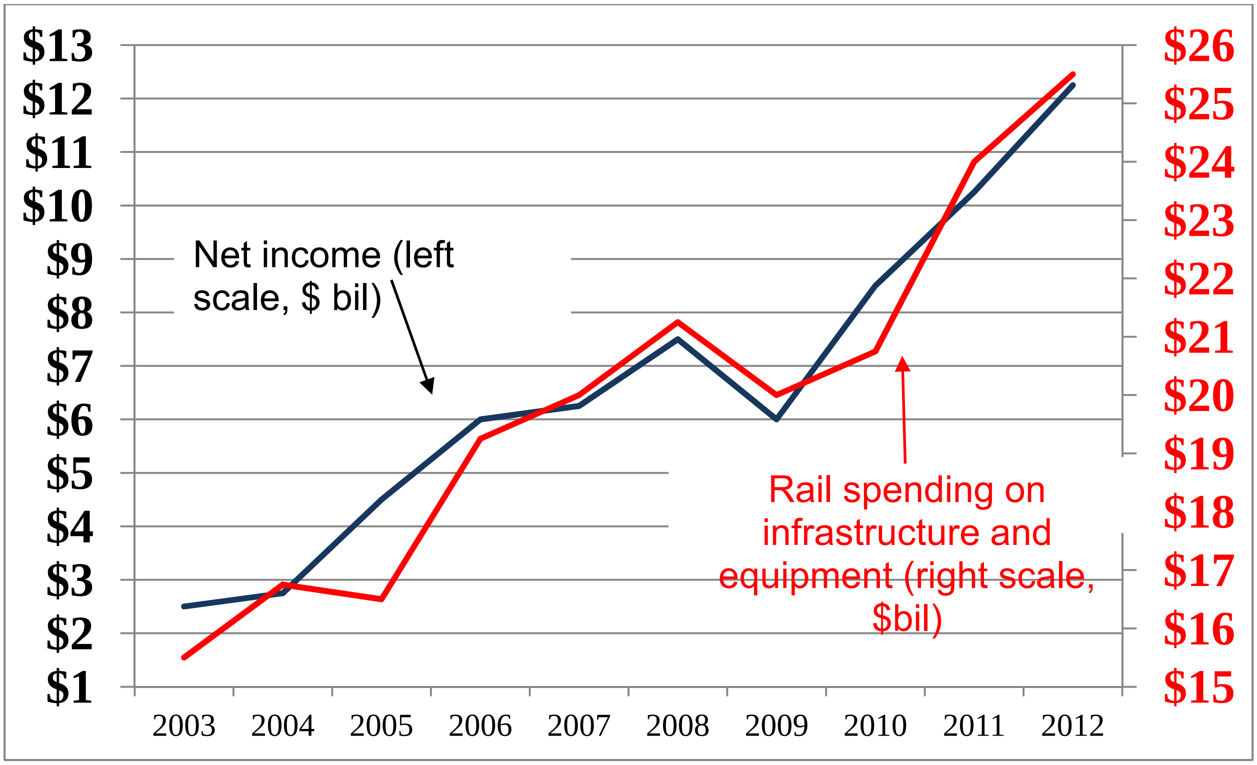
hand.[89] As shipper interests have argued in other contexts, long-term investments cannot be made without "stable and predictable regulatory policies" that support investor decisions "to commit the capital to back such investments."[90]

The need for financial certainty is highlighted by the fact that railroad earnings and investment are tightly correlated. Railroad investment is derived almost exclusively from private capital. Any regulation that threatens that private capital can stifle investment. As the table below illustrates, railroad investment tracks very closely to railroad earnings.

[89] *Id.*; *see also* James McClellan, "Railroad Capacity Issues", *Research to Enhance Rail Network Performance*, Transp. Research Bd. at 32 (2007) ("Building more tracks seems a natural solution but may not be the best alternative. A fixed plant is so called for a reason; once in place, it is costly to move the resources elsewhere. Thus, a different operating strategy (e.g., changing schedules or powering up some or all trains) is often a less costly and less risky solution; locomotives can be moved around, but track cannot.").

[90] Edison Electric Institute, *Transmission Investment, Adequacy Returns and Regulatory Certainty Are Key,* at 15 (June 2013) ("FERC must realize that utility decisions to make long-term investments, and investors' decisions to commit the capital to back such investments, depend on stable and predictable regulatory policies.") (enclosed as Attachment E).

Table 2
Correlation of Class I Income and Investment[91]



When railroads are financially successful and stable, more of that success is turned into investment in the system. Thus, an economically stable railroad benefits not just the railroad, but the shipping public and the Nation as a whole. The Board has itself recognized that financial stability is important to the rail industry.[92] Indeed, the effects of pre-Staggers era overregulation remind us that excessive regulation artificially depresses railroad earnings and slow investment and maintenance in the industry. As GAO found, prior to 1980,

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[91] Data are in current dollars and are for Class I railroads. Rail spending on infrastructure and equipment includes both capital spending and maintenance expenses. *See* Association of American Railroads, *North American Freight Rail Industry*, at 37 (Mar. 14, 2014), *available at* http://onlinepubs.trb.org/onlinepubs/railtransreg/Gray031414.pdf.

[92]Notice, Competition in the Railroad Industry, STB Ex Parte 705 at 7 (Jan. 11, 2011) ("A loss of revenue could lead to less capital investment, constraining capacity and deteriorating service for future traffic.").

> Years of declining profits led to deferred maintenance of rights-of-way, and over time plant and equipment deteriorated. Prolonged deferrals in maintaining and replacing worn-out capital stock affected safety and the quality of rail service.[93]

Unlike the pre-Staggers era, Class I carriers are investing massive amounts of capital to meet the capacity challenges facing the industry. Between 1996 and 2007, the rail industry invested 17% of total revenues in capital investments, compared to just 3% for the U.S. manufacturing sector.[94] According to FRA, industry "investment to expand capacity rose from $6.4 billion in 2005 to $10.2 billion in 2008."[95]

Regulatory uncertainty could prevent railroads from earning the revenues necessary to make necessary investments in infrastructure and technology. Even the threat of burdensome new regulation could chill investment. Capital investment requires confidence amongst the industry to ensure that such expenditures are economically justified:

> [Carrier] investment projections assume that the market will support rail freight prices sufficient to sustain long-term capital investments. If regulatory changes or unfunded legislative mandates reduce railroad earnings and productivity, investment and capacity expansion will be slower and the freight railroads will be less able to meet the U.S. DOT's forecast demand.[96]

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[93] U.S. GOV'T ACCOUNTING OFFICE, GAO/RCED-90-80, RAILROAD REGULATION: ECONOMIC AND FINANCIAL IMPACTS OF THE STAGGERS RAIL ACT OF 1980 10-11 (May 1990).

[94] Cambridge Systematics, *National Rail Freight Infrastructure Capacity and Investment Study*, at 4-12 (Sept. 2007) ("*Cambridge Report*"); Christensen Associates, *Analysis of Competition, Capacity and Service Quality*, Vol. II, at 16-4 (Nov. 2009).

[95] FED. R.R. ADMIN., PRELIMINARY NATIONAL RAIL PLAN 18 (Oct. 2009). In 2006, Class I railroads spent $8.5 billion on capital expenditures. $1.5 billion (18%) was on equipment and the remainder was roadway and structures. *Cambridge Report* at 4-11 – 4-12. In 2007, $1.9 billion was estimated to be spent on expansion of capacity through the construction of new roadway and structures, the highest level in recent years. *Cambridge Report* at 4-12.

[96] *Cambridge Report* at ES-2.

The prospect of significant changes in the regulatory environment will create a strong disincentive for carriers to undertake major capital projects. As GAO observed,

> Rail investment involves private companies taking a substantial risk which becomes a fixed cost on their balance sheets, one on which they are accountable to stockholders and for which they must make capital charges year in and year out for the life of the investment. A railroad contemplating such an investment must be confident that the market demand for that infrastructure will hold up for 30 to 50 years.[97]

The FRA has similarly warned against regulatory measures that would have the effect of reducing rail revenues, finding that "[f]reight rail infrastructure maintenance and capacity enhancements . . . can only occur with Federal legislation and policies that allow rail carriers to earn revenues that are sufficient to encourage their continued investment in the system."[98]

In the event that the Board ignores these principles and imposes a rate constraint based upon its flawed annual metric of financial health, it is not only the railroads that will suffer. The entire nation will suffer from a rail system that is mired by stifled investment, less capacity enhancement, and a lull in technological advancement. The Board should not act in such a manner. The regulatory regime developed by the Board must provide the industry with structure and security to enable it to heed the National call to continue to increase investment in the nation's rail corridors to meet the ever-growing needs of the national transportation system.

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[97] U.S. GOV'T ACCOUNTABILITY OFFICE, FREIGHT RAILROADS: INDUSTRY HEALTH HAS IMPROVED, BUT CONCERNS ABOUT COMPETITION AND CAPACITY SHOULD BE ADDRESSED 56 (Oct. 2006).

[98] FEDERAL RAILROAD ADMINISTRATION, PRELIMINARY NATIONAL RAIL PLAN: THE GROUNDWORK FOR DEVELOPING POLICIES TO IMPROVE THE UNITED STATES TRANSPORTATION SYSTEM 4 (Oct. 2009).

CONCLUSION

For the reasons set forth in these Reply Comments and Norfolk Southern's Opening Comments, the Board should abandon the independent revenue adequacy constraint and instead rely on its established and tested rate reasonableness remedies.

Respectfully submitted,

James A. Hixon
William A. Galanko
John M. Scheib
David L. Coleman
Garrett D. Urban
Norfolk Southern Railway Co.
Three Commercial Place
Norfolk, VA 23510

G. Paul Moates
Raymond A. Atkins
Matthew J. Warren
Hanna M. Chouest
SIDLEY AUSTIN LLP
1501 K Street, N.W.
Washington, DC 20005
(202) 736-8000

Counsel for Norfolk Southern Railway Company

November 4, 2014

BEFORE THE
SURFACE TRANSPORTATION BOARD
Docket No. EP 722

RAILROAD REVENUE ADEQUACY

REPLY VERIFIED STATEMENT

OF

MICHAEL R. BARANOWSKI

November 4, 2014

I. Introduction

I am Michael R. Baranowski. I am a Senior Managing Director of FTI Consulting, leading its Network Industries Strategies practice with offices at 1101 K Street, NW, Washington, DC 20005. I submitted a verified statement in the opening round of this proceeding. A statement of my qualifications is set forth in Exhibit MRB-1 to that statement. I have been asked by counsel for Norfolk Southern Railway Company ("NS") to compare the Net Railway Operating Income of the full NS system to the annual capital carrying charges for the DuPont Stand-Alone Railroad ("DRR") calculated by the Board in its October 3, 2014 corrected DuPont decision.[1]

In the March 21, 2014 *DuPont Initial Decision*, the Board determined that the hypothetical DRR would operate in 20 states with over 7,300 constructed route miles and another 820 miles in trackage rights and joint facilities.[2] The DRR would handle 6.2 million of NS's 2010 shipments[3] and would claim the majority of NS's overall revenues.[4] For its first full year of operations in 2010, the Board determined that the DRR would earn $5.8 billion in revenues and incur $7.2 billion in stand-alone costs, thus incurring a $1.4 billion revenue adequacy shortfall for that year.[5]

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[1] *E.I. DuPont de Nemours and Company v. Norfolk Southern Railway Company*, STB Docket No. 42125. The Board issued its initial decision on SAC costs in this proceeding on March 21, 2014 ("*DuPont Initial Decision*"). On October 3, 2014, the Board issued a decision making technical corrections to its Initial Decision based on submissions by the Parties ("*DuPont Corrected Decision*").

[2] *DuPont Initial Decision* at 14 and 46.

[3] *DuPont Initial Decision* at 14.

[4] DRR revenues are derived from the *DuPont Initial Decision* at 289, and NS revenues are derived from Norfolk Southern's 2010 10-K.

[5] *DuPont Corrected Decision* at 18, Table D-3.

At approximately 6.2 million shipments, the hypothetical DRR handles approximately 92 percent of the shipments handled by NS in 2010.[6] Based on a replacement cost estimate for road property assets of approximately $35.5 billion, the Board determined the annual amount of revenue above operating expenses required to cover the replacement cost of the road property assets over their projected life. Table 1 below shows these annual capital carrying charges for the years 2010 through 2013.

Table 1
DRR Capital Recovery
($ millions)[7]

Year	Capital Requirement Road Property
2010	$3,626.4
2011	$3,733.8
2012	$3,892.5
2013	$4,002.9

As explained above, the Board found that the hypothetical DRR is not revenue adequate. In fact, the revenues generated by the full NS system for the years 2010 through 2013 are also insufficient to meet the replacement-cost-based capital requirements for the less extensive DRR.

In order to accurately compare the earnings of the full NS system to the capital revenue requirement for the DRR, two adjustments to the Board's revenue adequacy Net Railway Operating Income ("NROI") calculations for the NS system are necessary. These adjustments are required because the DRR's capital revenue requirement includes depreciation and provides for Federal and state income taxes. Adding depreciation for road property assets and income taxes to NS's systemwide NROI results in an adjusted NROI that is directly comparable to the DRR's stand-alone capital revenue requirements. Table 2 below summarizes the adjustments to

[6] *DuPont Initial Decision* at 14.

[7] Source: *DuPont Corrected Decision* at Table D-1.

the NS system-wide NROI for the years 2010 through 2013 that I made to enable a direct comparison to the DRR's stand-alone revenue requirement.

Table 2
Adjustments to Revenue Adequacy NROI for NS Comparability with SAC Annual Revenue Requirement[8]

Description	2010	2011	2012	2013
Net Railway Operating Income	$1,668.0	$2,006.6	$1,903.8	$2,080.9
Road Property Depreciation	629.0	642.5	656.4	670.7
Income Taxes	875.8	1,039.8	1,045.2	1,099.9
Adjusted Net Railway Operating Income	$3,172.8	$3,688.8	$3,605.4	$3,851.5

Table 3 compares the DRR annual capital revenue requirement to the NS system Adjusted NROI and shows that the NS System Adjusted NROI falls short of the amount required to cover the DRR's capital requirement.

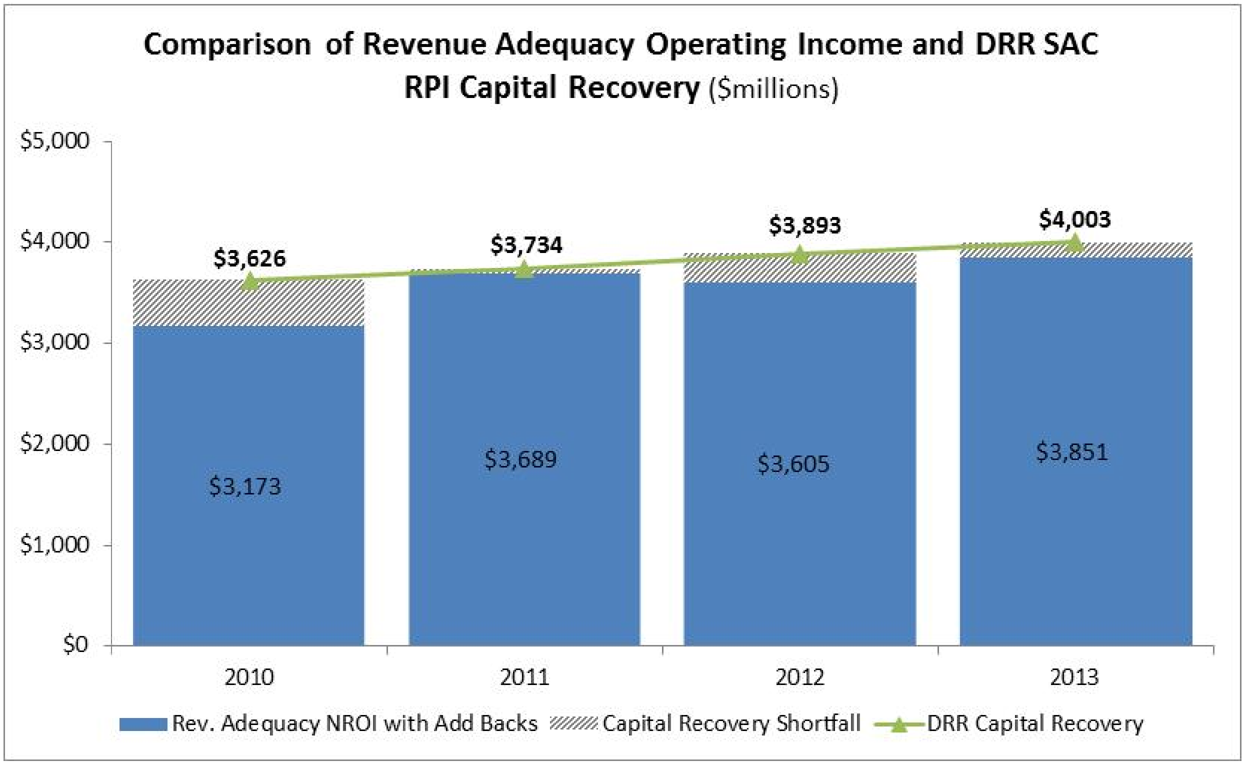
Table 3
Comparison of DRR Annual Capital Recovery to NS System Adjusted NROI

Year	Capital Requirement Road Property	NS System Adjusted NROI	Difference (Shortfall)
2010	$3,626.4	$3,172.8	($453.6)
2011	$3,733.8	$3,688.8	($44.9)
2012	$3,892.5	$3,605.4	($287.1)
2013	$4,002.9	$3,851.5	($151.4)

Figure 1 below depicts the Table 3 comparison graphically.

[8] Net Railway Operating Income for NS is derived from the Board's annual revenue adequacy determinations for 2010, 2011, 2012, and 2013 in Ex Parte 552. Road Property Depreciation and Income Taxes are derived from NS R-1 Schedules 412 and 210 for 2010, 2011, 2012, and 2013.

Figure 1



Comparison of Revenue Adequacy Operating Income and DRR SAC RPI Capital Recovery ($millions)
$5,000
$4,000
$3,000
$2,000
$1,000
$0
$3,626
$3,734
$3,893
$4,003
$3,173
$3,689
$3,605
$3,851
2010
2011
2012
2013
Rev. Adequacy NROI with Add Backs
Capital Recovery Shortfall
DRR Capital Recovery

I declare under penalty of perjury that the foregoing is true and correct. I further certify that I am qualified and authorized to sponsor and file this statement.

Executed on October 31, 2014

Michael R. Baranowski

Michael R. Baranowski

ATTACHMENT A

REPLY COMMENTS OF NORFOLK SOUTHERN RAILWAY COMPANY

STB EX PARTE NO. 722

RAILROAD REVENUE ADEQUACY

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Transmission Investment through Pricing Reform	))	Docket No. RM06-4-000

COMMENTS OF THE EDISON ELECTRIC INSTITUTE

ON NOTICE OF PROPOSED RULEMAKING PROMOTING TRANSMISSION INVESTMENT THROUGH PRICING REFORM

Submitted by
David K. Owens
Executive Vice President
Business Operations Group
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004
(202) 508-5000

Dated: January 11, 2006

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Promoting Transmission Investment through Pricing Reform	))	Docket No. RM06-4-000

COMMENTS OF THE EDISON ELECTRIC INSTITUTE

The Edison Electric Institute ("EEI") is submitting these comments in response to the Notice of Proposed Rulemaking ("NOPR"), issued by the Federal Energy Regulatory Commission ("FERC" or "Commission") on November 18, 2005, in the above-captioned proceeding.[1]

EEI is the trade association for shareholder-owned electric companies, and serves international affiliates and industry associates worldwide. Our U.S. member companies serve 97 percent of the ultimate customers in the shareholder-owned segment of the industry and nearly 71 percent of all electric utility ultimate customers in the nation. EEI members own approximately 60 percent of the nation's circuit miles of transmission.

Introduction

In the Energy Policy Act of 2005 ("EPAct" or "Act"), Congress recognized the essential role of a reliable and robust transmission system in meeting the nation's increasing demand for electricity by providing a package of provisions to strengthen the nation's transmission network. Not only does the Act create a self-regulating electric reliability organization ("ERO") and provide for reliability rules that are mandatory on all users, owners, and operators of the nation's transmission system, it also includes several

[1] *Promoting Transmission Investment through Pricing Reform*, 113 FERC ¶ 61,182 (2005), published at 70 Fed. Reg. 71409 (November 29, 2005).

provisions to advance the siting of new transmission facilities. In recognizing the growing importance of today's wholesale electricity markets in meeting regional needs, the Act grants the Commission the authority to approve the siting of electric transmission located in "national interest electric transmission corridors." Moreover, the Act streamlines transmission siting on federal lands by designating the U.S. Department of Energy ("DOE") as the lead federal agency to coordinate all federal approvals.

Beyond these measures to maintain reliability and improve siting, the Act opens the door to much-needed transmission investment. The Commission may now approve participant funding of new investment without regard to whether an applicant is a member of a Regional Transmission Organization ("RTO"). The depreciable lives for new electric transmission lines will be reduced from twenty years to fifteen for tax purposes. Central to this rulemaking, EPAct directs FERC to establish incentive-based rate regulations for transmission facilities that will attract investment, encourage new technologies, and assure cost recovery for reliability investments.[2]

While securing greater reliability, improved transmission siting, and expanded investment in transmission facilities are all critical elements of the package that Congress provided through the Act, promoting transmission investment through pricing reform in this rulemaking is an essential component of this package. FERC policies must recognize that industry's transmission investment plans point to unprecedented capital requirements – for both integrated companies and stand-alone transmission companies. As depicted in the Commission's recent *2004 State of the Markets Report*, both shareholder-owned integrated utilities and stand-alone transmission companies have budgeted substantial

[2] Energy Policy Act of 2005, section 1242,creating new section 219 of the Federal Power Act ("FPA").

increases in transmission investment over the 2004-2008 period.[3] The fact that current and planned transmission expenditures are increasing does not mean that the industry has reached a maximum level of investment, or that federal and state regulatory support for transmission investment is unnecessary. To the contrary, for increased transmission investment to become a reality, the industry must have supportive federal and state regulatory policies.

As the costs associated with transmission investment must ultimately be borne by ratepayers, state regulatory policies often drive the success or failures of policies to increase transmission investment. Moreover, because of state and regional differences, an incentive that may be beneficial to one company may prove to be of little value to another company. Only by providing utilities flexibility to request the particular regulatory treatment they need in a certain and timely manner can the Commission achieve full success of fulfilling its mandate from Congress to promote transmission investment.

Executive Summary

In its proposed rule addressing incentives to encourage investment in needed new transmission facilities, the Commission has proposed attractive returns and a number of other incentives including 100 percent of construction work in progress ("CWIP"), the expensing of pre-commercial operations costs, hypothetical capital structures, accelerated depreciation, recovery of costs of abandoned facilities, and deferred cost recovery. The Commission has also included provisions ensuring the recovery of prudently incurred costs related to transmission infrastructure under FPA sections 215 and 216. EEI

[3] *2004 State of the Markets Report*, Federal Energy Regulatory Commission, Staff Report by the Office of Market Oversight and Investigations, June 2005, at p. 27.

strongly supports these proposed incentives and believes they should be approved on an as-requested basis. This will allow utilities to select the incentive options that best address their particular investment needs. EEI believes that all new prudently incurred capital investment in electric transmission facilities should be automatically approved.

In promoting greater capital investment in new transmission capacity, the Commission needs to provide for an accurate estimate of a company's cost of common equity in addition to incentive-based rate treatments intended to increase transmission investment. These are separate issues, and both are important to ensure that companies are compensated adequately for the risks involved in investing in new transmission facilities.

EEI encourages the Commission to make use of return on equity ("ROE") adders as a way to provide meaningful incentives in a timely and certain manner. ROE adders can be highly effective at providing an incentive to increase transmission investment, particularly if the process of awarding an ROE adder does not require a lengthy comprehensive rate case under section 205 of the FPA. EEI supports a 100 basis point ROE adder incentive for all new transmission investment. Because ROE adders can also serve as an incentive mechanism to foster regional transmission planning, the Commission should provide an ROE adder for all transmission facilities planned through open and fair regional planning processes acceptable to the Commission.

EPAct directs the Commission to provide incentives to each electric utility that joins a transmission organization. EEI supports a 50 basis point ROE adder for all utilities that join or have joined and continue as supportive members of RTOs, Independent System Operators ("ISOs"), and other transmission organizations.

EEI agrees with the Commission that applicants likely would consider the time requirements and the uncertainties associated with a comprehensive rate proceeding, encompassing their entire transmission systems, to be a disincentive to making incentive filings. To eliminate this disincentive, EEI supports single-issue ratemaking.

To be consistent with the intent of Congress, the goal of this NOPR should be to design incentives that will encourage the construction of new transmission infrastructure, regardless of the ownership of facilities. FERC transmission policies should not favor one corporate structure, business model, or retail regulatory model over another. FERC should be flexible and allow individual transmission owners to propose any additional incentives that meet their particular needs. This is important particularly with respect to the role of the states and their broad jurisdiction over cost recovery and corporate structure.

EEI believes that, whether public power is or is not involved, a consortium that builds new transmission infrastructure whose costs are recovered in FERC-approved rates should receive the same incentives that all other FERC-jurisdictional public utilities receive for building new projects

The industry has long been receptive to performance-based regulation ("PBR"), provided that it shares benefits fairly and provides an appropriate risk-return balance. Of course, PBR policies should be entered into voluntarily.

EEI supports exploring ways to encourage the deployment of advanced transmission technologies. However, the Commission should avoid linking incentives to a predetermined list of "advanced" technologies. There is increased risk in deploying a technology that may not be as fully tested. In instances where the use of an advanced technology would provide particular benefits that cannot be achieved from other technologies, an incentive may be necessary to ensure that the project utilizing the advanced technology is able to move forward. EEI encourages the Commission to provide for such special incentives, in the form of an ROE adder that is sufficient to balance the increased risks for such projects.

The Commission also requested comments on additional provisions that would accomplish the transmission investment objectives of the Act. EEI believes that the almost routine imposition of a five month suspension of rates serves as a strong disincentive to transmission providers to construct new transmission infrastructure. Delaying the effective date of rates forces a utility to absorb the costs associated with the new facilities during the suspension period, thereby effectively reducing that utility's return on equity. The negative rate impact of such lengthy suspensions may far outweigh the positive impact of the various affirmative incentives that are being considered in this NOPR. The Commission should allow timely rate relief for utilities' new transmission investment to avoid penalizing utilities for constructing significant new transmission facilities.

In an effort to monitor the effectiveness of its transmission incentives rule, the Commission has proposed to require public utilities annually to report their actual and planned capital spending on electric transmission projects and, in addition, to provide detailed information on each facility involved. The mandatory collection of such information, in particular relating to planned facilities, poses a number of serious concerns. Instead, EEI encourages the Commission simply to monitor the number of applications for new transmission facilities that are filed, the magnitude of facilities involved, and the incentives sought – this will give the most accurate measure of the effectiveness of the incentives rule over time. If additional information on actual expenditures beyond what is available in the FERC Form 1 is required, EEI encourages the Commission to rely on annual aggregate transmission investment information that EEI has provided in the past for the Commission's benefit.

COMMENTS

I. EEI Supports the Proposed Incentives Available to All Jurisdictional Public Utilities

In March of 2005, EEI's Board of Directors approved the attached EEI Principles on Transmission Investment ("EEI Principles"), which articulate EEI's policy positions on transmission investment. (*See* Appendix A). Among other things, the EEI Principles stress the need for cost recovery, and the elimination of various impediments that continue to frustrate and delay transmission investment. By providing regulatory certainty, particularly with respect to attractive returns, incentives, cost allocation and cost recovery, the Commission can support public utilities in raising the capital necessary to construct needed, cost effective transmission facilities.

Furthermore, Congress has recognized the importance of incentives to promote transmission investment by enacting new section 219 of the Federal Power Act ("FPA") as section 1241 of EPAct. Congress specifically directed the Commission to develop the rule that is the subject of this rulemaking. The rule shall "promote reliable and economically efficient transmission and generation of electricity by promoting capital investment in the enlargement, improvement, maintenance, and operation of all facilities for the transmission of electric energy in interstate commerce, regardless of ownership."

FPA section 219(b)(1). The rule also must provide for a "return on equity that attracts new investment in transmission facilities" and allows recovery of all prudently incurred costs related to transmission infrastructure developed under FPA sections 215 and 216. FPA section 219(b)(4).

Consistent with these Congressional directives, the Commission has proposed attractive returns and a number of other incentives including 100 percent of construction work in progress ("CWIP"), the expensing of pre-commercial operations costs, hypothetical capital structures, accelerated depreciation, recovery of costs of abandoned facilities, and deferred cost recovery. The Commission also has included provisions ensuring the recovery of prudently incurred costs related to transmission infrastructure under FPA sections 215 and 216. EEI strongly supports these proposed incentives and believes they should be approved on an as-requested basis. This will allow utilities to select the incentive options that best address their particular investment needs and will stimulate planning and investment in national interest electric transmission corridors.

EEI encourages the Commission to ensure that the incentives in fact are readily available to applicants. In recent transmission rate decisions, the Commission has denied some of the very incentives it proposes in the NOPR to provide, raising a concern about whether these incentives in fact will be made readily available.[4] If the incentives are not generally available to applicants, the Commission will not reach its goal and that of Congress to encourage investment in new transmission facilities needed to improve reliability and reduce congestion.

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[4] *Southern California Edison Co.*, 114 FERC ¶ 61,018 at P 15 (Jan. 9, 2006).

In addition, although not addressed in this rulemaking, the Commission should remain mindful of the need to remove remaining disincentives to increased transmission investment. For example, see discussion of Commission's five-month suspension policy. Consistent with the EEI Principles, the Commission's transmission pricing policy should also ensure cost recovery through effective cost allocation. To the extent practicable, cost responsibility should follow cost causation and the potential for cost shifting should be minimized. However, existing RTO and ISO tariffs should not be affected. FERC also should be open to proposals that deviate from the "higher of" policy where justified.[5] Moreover, where states require purchases of renewable resources that lack siting flexibility, FERC should allow alternative transmission pricing and cost recovery approaches to support the building of transmission facilities to help achieve state renewable resource goals.

A. The Commission Should Streamline the Application Process by Providing Automatic Approvals, ROE Adders, and Single-Issue Ratemaking

1. The Commission Should Provide for Automatic Approval of Applicants' Requests for Incentives

The Commission identifies and proposes six incentives to be available to all jurisdictional public utilities to foster increased transmission investment. NOPR at P 19-35. Public utilities would be required to request incentives and file for approval under FPA section 205. NOPR at P 18. What is not clear, however, is whether the Commission envisions a streamlined approval process or a protracted, potentially litigated approach to awarding incentives. The time requirements and uncertainties associated with a comprehensive, case-by-case review of each application will

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[5] *See* EEI Comments on Notice of Inquiry Preventing Undue Discrimination and Preference in Transmission Services, pages 28-30. Docket No. RM05-25-000. (Filed on November 22, 2005).

significantly discourage incentive filings and may completely negate the intended incentive. An effective incentives program to increase transmission investment must provide benefits with certainty and in a timely manner.

The Commission should establish that its proposed incentives will be automatically approved upon a showing that new transmission investment will "help to ensure reliability and reduce transmission congestion" *See* NOPR at P 19. EEI believes that all new prudently incurred capital investment in electric transmission facilities, including upgrades to the existing transmission system as well as system expansion through the addition of new transmission lines, will satisfy this test.

2. ROE Adder Mechanisms Can Streamline the Approval of ROE Incentives to Attract Greater Investment in Transmission Facilities

The Commission states that the purpose of this rulemaking is to promote greater capital investment in new transmission capacity. *See* NOPR at P 2. However, in addressing the allowed return on equity ("ROE"), the Commission maintains that it will continue to consider and approve ROE levels that attract new transmission projects. *See* NOPR at P 21. EEI believes that this approach involving lengthy proceedings to determine the appropriate ROE that will allow a company to recover its cost of capital falls short of providing incentives to promote increased transmission investment. EEI encourages the Commission to make use of ROE adders as a way to provide meaningful incentives in a timely and certain manner.

a. EEI Supports a 100 Basis Point ROE Adder for All New Transmission Investment

An ROE adder is a basis point increase in the Commission-approved ROE component of a public utility's allowed return. ROE adders can be highly effective at providing an incentive to increase transmission investment, particularly if the process of awarding an ROE adder does not require a lengthy comprehensive rate case under section 205 of the FPA. EEI supports a 100 basis point ROE adder incentive for all new transmission investment or a greater adder as the Commission may deem appropriate. As discussed above in section I.A.1. of EEI's comments, the Commission should provide for the automatic approval of applications for incentive rate treatments, including ROE adder incentives, for all prudently incurred capital investment in electric transmission.

b. The Commission Should Consider an Incentive-Based ROE Adder to Promote Open and Fair Regional Transmission Planning

All prudently incurred capital investment in electric transmission should qualify for the Commission's incentives to help ensure reliability and reduce transmission congestion. While participation in a Commission-approved independent regional planning process should be encouraged by the Commission, a strict requirement may have the unintended effect of slowing additional transmission investment in regions currently without Commission-approved planning processes.

EEI believes that a regional planning process can identify cost-savings opportunities and facilitate the construction of new transmission to support robust wholesale markets and improved reliability. Within RTOs and ISOs, transmission is planned through Commission-approved processes. At the same time, the Commission's authority to mandate regional planning is limited. ROE adders can serve as an incentive mechanism to foster regional transmission planning. The Commission should provide an

ROE adder for transmission facilities planned through open and fair regional planning processes acceptable to the Commission, including processes managed by independent transmission administrators,[6] other regional planning groups, as well as RTOs and ISOs.

3. Single Issue Ratemaking for New Projects Can Provide a Strong Incentive for New Investment

As the NOPR points out, applicants are likely to consider the time requirements and the uncertainties associated with a comprehensive rate proceeding that encompass their entire transmission systems to be a disincentive to making incentive filings. NOPR at P 54. To eliminate this disincentive, the Commission should provide for the recovery of FERC-jurisdictional costs of new transmission facilities without instituting a comprehensive rate case proceeding. Public utilities should be permitted to file with the Commission to establish a revenue requirement to recover the costs of constructing a specific new transmission facility pursuant to section 205 of the FPA. Under this approach, the transmission owner determines whether to establish a new ROE or use its current Commission-approved ROE. Any ROE incentive adders are combined with the ROE to determine the new facility's revenue requirement.[7]

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[6] For example, in *Duke Power*, 113 FERC ¶ 61,288 (December 19, 2005), and *MidAmerican Energy Company*, 113 FERC ¶ 61, (December 16, 2005), the Commission approved OATT amendments under which the planning process would be administered for the transmission providers by independent entities. Similar OATT amendments are pending before the Commission in *Entergy Services, Inc.*, Docket No. ER05-1065-000. Such independent transmission administrators and regional planning groups should also be eligible to qualify, on a case-by-case basis, as "Transmission Organizations" under Section 219 of the FPA.

[7] It is important to establish a crediting mechanism in some cases to harmonize the rate treatment for new and existing transmission facilities. *See Allegheny Power System Operating Co.'s, et al.*, 111 FERC ¶61,308 (2005) at P 54, *reh'g. requested; See also* Request For Rehearing of The PJM Transmission Owners, Docket No. ER05-513-000, filed on June 30, 2005.

B. In Promoting Greater Capital Investment in New Transmission Capacity, the Commission Should Not Confuse an Accurate Estimate of a Company's Cost of Common Equity with Incentive-Based Rate Treatments

Regulatory ratemaking seeks to provide utilities a rate of return equal to their cost of capital. Because the cost of capital is an element of the cost of service, accurate cost of capital determination should be addressed independently of any subsequent application for incentives. A large part of a utility's capital structure is comprised of common equity. A utility's required cost of common equity or allowed return on equity is an important input to setting rates. An allowed ROE that is set below the return in capital markets on alternative investments of equivalent risk will constrain greater capital investment in new transmission investment. EEI encourages the Commission to be open to improvements in estimating a utility's cost of capital. This can ensure that a company's ROE is determined as accurately as possible.

1. The Commission Should Be Open to Proposed Improvements to Its DCF Methodology

Accurate cost of capital determination is essential to ensure adequate investment in needed transmission. As applied by Commission staff, the discounted cash flow ("DCF") methodology does not account for different degrees of financial leverage (risk) among utilities to which a given utility is being compared.[8] Failure to recognize, and

[8] The DCF method posits that a firm's market-required return on equity is the discount rate that equates expected future cash flows from owning a share of common stock to its current market price. These cash flows may result from (1) future dividends, and (2) total share price appreciation as of the time the stock is sold. Since it is impossible to know and tedious to compute future cash flows from both of these sources, a simplified version of the DCF model generally is used. This simplified model assumes constant growth in dividends and earnings, along with other simplifying assumptions, so that the market-required return on equity can be determined as a function of the current dividend, the current share price, and the long-term (constant) growth rate.

adjust for, such differences can result in material errors in cost of equity estimation. The solution is to use the after-tax weighted-average cost of capital to adjust for leverage differences among sample companies.[9] In addition, Commission staff uses the *market* value of equity to estimate the market cost of equity, then applies this rate of return to the *book* value of equity to calculate the equity return component of revenue requirements. This is fundamentally inconsistent. For utilities whose market to book ratio exceeds 1:1, it means they are unable to achieve the market required return estimated by the DCF. The solution is to apply DCF results to the market value of equity.

2. Consideration of Additional ROE Estimation Methods Can Enhance the Accuracy of Cost of Capital Determinations

The Commission and its rate case staff should be open to utility proposals to employ additional methodologies, beyond DCF, that can enhance the accuracy of cost of capital determinations. Using other financial models will permit the Commission to base its cost of capital determinations on a broader set of information, so that its decisions are not held hostage to short-term aberrations that distort the results obtained from a single financial model. Examples of other methods include the following: risk premium models, the Capital Asset Pricing Model ("CAPM"), and comparable earnings methods.

Risk premium models calculate the cost of equity as the sum of a low-risk interest rate (e.g., a government bond or a corporate bond index), plus a premium tied to the utility's risk profile. Such models present fewer estimation problems than DCF.

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[9] *See The Effect of Debt On the Cost of Equity In a Regulatory Setting*, The Brattle Group (prepared for EEI), January 2005.

The CAPM is the best-known example of a "risk positioning" model. Developed initially for use in managing stock portfolios, the CAPM calculates the market-required return for any equity (ROE for any company) as the sum of the risk-free rate, and a premium that is a function of the market price of risk and the equity's particular risk profile. An equity's risk profile is measured by a single term, beta, which is calculated as the slope of the regression line fitting the utility's equity returns to those of a broad market basket of stocks. Beta is intended to measure an equity's non-diversifiable risk. The comparable earnings method takes an average of realized accounting (book) returns for comparable companies. Usually, the comparable companies are outside the utility sector and determined to be of comparable investment risk based upon published risk measures such as beta, bond rating, or other investor information services.[10]

C. EEI Supports the Option of Allowing 100 Percent of CWIP in Rate Base and the Expensing of Pre-Commercial Operations Costs

The Commission proposes to allow public utilities to include up to 100 percent of prudently incurred transmission-related CWIP in rate base and to permit the expensing of prudently incurred pre-commercial operations costs. *See* NOPR at P 27. Since 1987, the Commission's general policy has been to allow only 50 percent of the non-pollution control/fuel conversion construction costs as CWIP in rate base.[11] The remaining construction costs (including an accrual of allowance for funds used during construction ("AFUDC") which provides a return on those expenditures) generally would be

[10] In addition to the foregoing conventional methods, multifactor models (*e.g.*, as described by Fama & French; Elton, Gruber, and Mei), are not in use in regulatory jurisdictions today, but are under active development and may be available in the near future.

[11] *See* 18 CFR section 35.25(c) (3)

capitalized and included in rate base only when the plant went into commercial operation, *i.e.*, when the plant became used and useful. *See* NOPR at P 24.

EEI agrees that the Commission's proposal for inclusion of up to 100 percent of prudently incurred transmission-related CWIP is appropriate and should be available to utilities when they request it. This will encourage transmission construction through improved cash flow and greater rate stability and will have the benefit of lower future rates to customers. EEI also supports the Commission's proposal to permit the expensing of pre-commercial operations costs rather than capitalizing these costs when requested by a utility. This can reduce construction costs by minimizing the amount that needs to be financed by debt or equity, and this will further facilitate the new construction financing and provide improved cash flow.

All pre-construction activities for projects and construction costs should specifically be considered "pre-commercial operation costs." In this regard, the Commission should consider all costs that may be associated with planning, related studies, and siting. For example, the cost of obtaining regulatory approvals and construction costs (which are not typically recovered entirely in rate base until commercial operation commences), should be classified as "pre-commercial operation costs." Accordingly, EEI proposes that "pre-commercial" operation costs should include, but not be limited to, the following costs and associated overheads:[12]

1) *Planning, design and engineering to determine the best alternative transmission route*, including: (a) computer simulation to evaluate the expected performance and effectiveness of possible alternatives; (b) cost/benefit analysis of possible alternatives; and (c) studies to examine

[12] See *American Transmission Company, LLC*, 105 FERC ¶ 61,388 (2003), *order approving settlement*, 107 FERC ¶ 61,117 (2004).

the relative environmental, social and ecological impact of potential routes.

2) *Technical and legal services needed to complete regulatory filing requirements specified by Federal, State, Local regulatory agencies*, including the services provided by legal and technical experts to prepare all documents required by various regulatory bodies with authority to certify the proposed transmission route.[13]

3) *Studies and consulting services which address information requests during the certification and siting process*, including: special studies that the transmission owner may be required to provide in the course of the certification process.

4) *Public meetings and processes to seek input and share information regarding the proposed project's need and route*, including public information, newspaper publications and public information meetings.

5) *Development and implementation of interim measures to maintain adequate reliability level due to the delayed completion of the proposed project*, including interim measures to mitigate delay in the implementation of the project due to lengthy route certification processes.

6) *All planning, engineering, design, material procurement and labor associated with the construction of the project*, including all cost incurred prior to the commercial operation of the project.

The Commission should also consider certain costs that have been traditionally expensed, including the costs of resetting relays, using a mobile transformer, making payments to other transmission owners for upgrades to their lines, and the write-off of the undepreciated cost of facilities that are being replaced with new transmission investment, as pre-commercial operations costs. Moreover, it is important that a utility can choose the pre-commercial operations costs that are to be expensed and also the pre-commercial

[13] This may include environmental, ecological, archeological and other technical or scientific studies survey, and procurement of rights-of-way.

operations costs sought for 100 percent CWIP recovery. This policy will provide utilities with the necessary flexibility to respond to the unique needs of each investment project.[14]

D. Hypothetical Capital Structures Should Be an Option

Hypothetical capital structures may be particularly useful for businesses that are emerging from financial distress or entering a large capital expenditure program that may be aiming for a capital structure they have not yet realized. EEI believes the Commission should be open to considering requests to employ hypothetical capital structures and that such requests should be reviewed on a case-by-case basis.

E. EEI Supports Accelerated Depreciation on an As-Requested Basis

The NOPR appropriately recognizes that allowing utilities to use accelerated depreciation is a means to increase cash flow to utilities and thereby remove a potential disincentive to investing in transmission facilities.[15] EEI strongly supports allowing utilities to have the choice to depreciate transmission facilities over a period of fifteen years in place of the typical Commission practice to allow depreciation over the useful life of the facilities. EEI notes that undertaking significant new transmission investment can present cash flow issues for utilities regardless of corporate structure, and therefore urges the Commission to make clear in its Final Rule that all public utilities regardless of corporate structure will have the option of accelerated depreciation**.**

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[14] For example, this approach would allow for the tracking and recovery of all pre-commercial costs required for single-issue ratemaking for new projects.

[15] *See* NOPR at P 30. Note that in Order No. 2000, the Commission found that it is appropriate to provide those willing to make new transmission investments with the flexibility to propose that such assets follow non-traditional depreciation schedules, and the Commission explained that the purpose of providing such flexibility is to remove disincentives for the construction of new facilities Order No. 2000 at ¶ 31,194.

EEI agrees that in some circumstances using accelerated depreciation is an appropriate choice for utilities, and therefore the Commission's policy should allow utilities flexibility with respect to that option. Moreover, the availability of accelerated depreciation can foster the refurbishment of existing transmission assets and prevent the derating of equipment. Thus, EEI believes that, on an as-requested basis, the Commission should find that fifteen years is an appropriate time period for cost recovery and that utilities should be permitted to match the tax law depreciation methodology, which weights the tax depreciation more heavily toward the beginning of the life of the project rather than spreading it evenly over fifteen years. EEI further believes that, in some cases, it may be appropriate for the Commission to find a shorter depreciable life for certain new transmission facilities. Accordingly, the Commission should not establish a presumption of a shorter or longer depreciable life for new transmission facilities.

In the NOPR, the Commission also sought comment on whether accelerated depreciation has any longer-term negative impacts that would undermine the goals of the Act. In this regard, issues may arise, for example, related to the treatment of facilities that will have a useful life beyond fifteen years – this is one of the reasons EEI suggests that the Commission allow a utility the flexibility to choose whether and how to accelerate depreciation of its transmission facilities to appropriately meet its circumstances with the goal of increasing transmission investment.

F. Recovery of Costs of Abandoned Facilities Will Improve Regulatory Certainty

EEI believes that the Commission's present policy to limit recovery from ratepayers to only 50 percent of a utility's prudently incurred investment in abandoned or cancelled plant (*i.e.*, facilities not completed and placed into operation) presents an obstacle to investment in large-scale transmission projects. Where a public utility does not control the decision to develop or abandon the transmission project or, in the case of interconnections, generation facilities, the Commission's existing policy does not serve the Commission's articulated objective of ensuring that transmission providers weigh the risk of abandonment or cancellation before embarking on project.[16] Thus, in *Southern California Edison Co.*, 112 FERC ¶ 61,014 at P58-61, *reh'g. denied*, 113 FERC ¶ 61,143 at P 9-15 (2005), recognizing this distinction, the Commission granted a public utility's request to recover 100 percent of the prudently-incurred costs even if the subject facilities are abandoned or cancelled.

EEI believes that extending recent precedent on abandoned cost recovery to requesting utilities is warranted in light of the need to attract new transmission investment. In particular, the Commission may reduce the uncertainty associated with higher risk projects by providing for recovery of 100 percent of the prudently-incurred costs of facilities that may later be cancelled or abandoned due to factors, which the Commission finds to be beyond the control of the public utility requesting such cost recovery.[17] In this manner, the Commission's proposed policy for the recovery of

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[16] *See, e.g., New England Power Co.*, Opinion No. 295, 42 FERC ¶ 61,016 at 61,068, *order on rehearing*, 43 FERC ¶ 61,285 (1988)("Opinion No. 295")(public utility's management had control over the development of the cancelled nuclear power plant).

[17] EEI believes that such costs should include all siting and planning (*i.e.*, "pre-commercial") costs for such facilities. EEI notes that MISO's tariff provides that costs for network upgrades not completed shall include, but are not limited to: the costs associated with attempting to obtain all necessary approvals for the project and studies and any construction costs. See MISO TEMT, Attachment N, Section G (Second Revised Sheet No. 1,309).

abandoned plant costs would strike an equitable balance between the interests of investors and ratepayers.

G. Only with Federal and State Collaboration Can Deferred Cost Recovery Avoid Trapped Costs and Provide Other Benefits

The Commission proposes to permit utilities to use a deferred cost mechanism that allows them to begin recovery of new facility costs in FERC-jurisdictional rates at the end of a retail rate moratorium. *See* NOPR at P 35.

As a threshold matter, conflicting federal and state policies and regulatory models will more than just "undermine incentive ratemaking at the federal level."[18] Where state commissions retain jurisdiction over transmission rates, the very efficacy of the Commission's initiative hinges on state support. Thus, EEI supports the Commission's proposal to allow utilities to use deferred cost recovery when requested by the transmission owner. Deferred cost recovery can be helpful to utilities facing conflicting federal and state policies that can lead to "trapped costs."[19] Allowing some utilities to use deferred cost recovery will allow them to rationalize revenue streams and thereby prevent rate shocks. Accordingly, allowing public utilities subject to retail rate moratoriums to avail themselves to a deferred cost recovery mechanism may be helpful towards encouraging investment in such transmission facilities by improving regulatory certainty. However, EEI cautions that these benefits will not be possible without a high level of federal-state collaboration.

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[18] *See* NOPR at P 39 wherein the Commission recognizes that investments by traditional public utilities subject to company-wide state-level rate case face risks that can undermine incentive ratemaking at the federal level.

[19] "Trapped costs" are costs that are not recoverable from ratepayers as a result of inconsistent regulatory policies. Costs may be trapped as a result of state rate freezes or federal/state regulatory inconsistencies. For example, a trapped cost may occur when the Commission issues a decision requiring a utility to take a particular action, while the state sets the utility's rates as if the utility had made a different choice.

Since investments by traditional public utilities are generally subject to company-wide-state-level rate case risks, EEI believes it is critical that the Commission work with state regulators to resolve state/federal issues if this proposal is to be effective. It is essential for this proposal that the Commission to make sure cost recovery is actually possible. Clearly, if states oppose the proposal, then it will not work. Therefore, it is imperative that the Commission reach out to the states. The Commission must ensure that the necessary regulatory mechanisms are in place to allow cost recovery and should cooperate with the states on developing these recovery mechanisms, including transmission cost recovery tracker mechanisms. A reasonable balance must be struck between the states' regulatory model and their legitimate retail ratepayer protection interests on one hand, and the Commission's broader national economic interests and concerns on the other. Only by working in close partnership with states can the Commission achieve full success in fulfilling the purposes of FPA section 219.

II. FERC Transmission Policies Should Not Favor One Corporate Structure or Business Model

The Commission proposes to encourage the formation of stand-alone transmission companies or transcos by permitting these public utilities to receive an ROE that both encourages transco formation and is sufficient to attract new investment. *See* NOPR at P 40. Thus, the Commission is offering transcos two separate ROE incentives: an ROE incentive to attract new investment that will be permitted for all public utilities and an additional ROE incentive to encourage the formation of transcos. In addition, the Commission proposes to encourage transco formation by also providing adjustments to transco rates to provide recovery of Accumulated Deferred Income Taxes ("ADIT") to remove any disincentives that might prevent the sale or purchase of transmission assets. *See* NOPR at P 43.

EEI believes that to be consistent with the intent of Congress, the goal of this NOPR should be to design incentives that will encourage the construction of new transmission infrastructure, regardless of the ownership of facilities. FERC transmission policies should not favor one corporate structure, business model, or retail regulatory model over another. EEI also believes FERC should be flexible and allow individual transmission owners to propose other incentives that meet their particular needs. This is important particularly with respect to the role of the states and their broad jurisdiction over cost recovery and corporate structure.

A. FERC Incentives Should Be Designed to Encourage Transmission Investment Rather Than Changes to Corporate Structure or Business Models

The focus and the goal of the newly-enacted section 219 of the Federal Power Act is to promote investment in transmission. Moreover, the need for increased transmission investment is immediate, while changing corporate business models is a long-term issue. In accordance with section 219(b) of the FPA, the Commission needs to support all transmission owners in building new transmission infrastructure. FERC incentive policies should not give the impression that the Commission is seeking to restructure the transmission sector, whether intended or not. FERC should focus on the near-term and critical objective of increasing transmission investment by supporting all entities, regardless of business model, that invest in transmission infrastructure.

This position is consistent with policies adopted by EEI's member companies.

Specifically, as mentioned above, the EEI Board of Directors approved the attached EEI Principles in March 2005, articulating EEI's policy positions on transmission investment (S*ee* Appendix A). Among other things, the EEI Principles stress the need for cost recovery, and the elimination of various impediments that continue to frustrate and delay transmission investment. Importantly, the EEI Principles stress that EEI supports <u>all</u> transmission business models, and that many different structures and business models can coexist in a competitive wholesale marketplace for the construction of transmission, provided there are fair rules in place for all market participants. The Commission should focus on encouraging industry behavior that increases transmission investment, and should avoid trying to manage business models. Corporate structures should be left to jurisdictional utilities. FERC transmission policies should not favor any particular corporate structures or business models.

B. FERC Should Be Flexible in Allowing Transmission Owners to Define the Structure of Their Business and the Incentives They Need

In this docket, the Commission has proposed a range of incentives available to all public utilities to promote transmission investment. EEI supports this approach. However, the Commission should also allow individual companies to propose, on a case-by-case basis, any additional incentives that work in the context of each entity's particular business model, financial structure, or regulatory posture. An incentive that may be beneficial for one company may prove to be of little or no value to another company. FERC should approve incentives through this rulemaking that encourage investment by all transmission owners while considering the particular needs of each entity on a case-by-case basis.

As the costs associated with transmission incentives must ultimately be borne by retail ratepayers, state regulatory policies often drive the success or failure of an incentive. Just as was the case with the Commission's standard market design proposal[20],the states have a vital role in regulating electric transmission. In order for the Commission's transmission investment policies to succeed, state concerns must be addressed. As individual companies are in a much better position to understand the efficacy of particular incentive mechanisms as applied to them, particularly with respect to any state issues, the Commission should allow applicants to define the structure of the business and the incentives they need to successfully increase transmission investment.

[20] Docket No. RM01-12-000, *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*; FERC's NOPR in this proceeding was issued on July 31, 2002 and order terminating proceeding was issued on July 19, 2005.

In this way, the Commission can provide incentives to encourage increased transmission investment without attempting to prescribe particular corporate structures that may not prove to be fruitful when applied to individual companies.

III. The Commission Should Offer a 50 Basis Point ROE Adder for Utilities that Participate in a Transmission Organization

The Energy Policy Act directs the Commission to provide incentives "to each . . . electric utility that joins a Transmission Organization." EPAct section 1241, adding new FPA section 219(c). The Commission indicates that it will continue to consider requests for ROE-based incentives for utilities that join an RTO and it will extend this consideration to utilities that join an ISO. *See* NOPR at P 45. EEI supports making this incentive available to those utilities that join or have joined and continue as supportive members of RTOs, ISOs, and other transmission organizations.

In a recent decision, the Commission rejected Southern California Edison Company's ("SCE") request for an incentive adder for its membership in an ISO.[21] The Commission stated that such an adder is intended to be an incentive for transmission owners to turn over operational control of their transmission facilities to an ISO or RTO, and thus "does not apply to transmission owners who have already done so, as they need no inducement to take such an action."[22] EEI believes that denying an incentive to existing Transmission Organization members while awarding it to new members who join these organizations unfairly discriminates against those entities that should be

[21] *Southern California Edison Co.*, 114 FERC ¶ 61,018 at P 15 (Jan. 9, 2006).
[22] *Id.; see also Allegheny Power System Operating Co's, et al.*, 111 FERC ¶61,308 (2005) at P 54, *reh'g. requested* (questioning whether an incentive should be offered to a long standing utility member of an RTO).

rewarded for taking the initial step of establishing and joining an independent Transmission Organization. FERC should grant 50 basis points to all who attain Congress' goal of joining a Transmission Organization. Providing a 50 basis point adder to existing Transmission Organization members rewards these utilities for remaining members of the Organization.

IV. EEI Supports the Use of Performance-Based Policies to Encourage Efficiency

The industry has long been receptive to performance-based regulation ("PBR"), provided that it shares benefits fairly and provides an appropriate risk-return balance. At a time when transmission rates are increasing - reflecting new spending to expand transmission capacity and increase system reliability for all users, and in some regions, to develop organized wholesale markets, properly designed PBR mechanisms may help contain cost growth by encouraging increased efficiency of regulated operations, both in the construction of new capacity, and in the operation of existing capacity. At the same time, EEI cautions that poorly designed PBR mechanisms may defeat the goal of building new transmission infrastructure. Of course, PBR policies should be entered into voluntarily. To ensure symmetry and fairness, they should never be imposed, but should be the product of a negotiation that is mutually acceptable to the Commission and the utility, or utilities, involved.

A. PBR Should Not Be an Alternative for Adequate Allowed Return

The adoption of a PBR mechanism should not lead the Commission to approve an allowed return that is lower than it otherwise would be (*e.g.*, on the assumption that the PBR will allow the utility to make up the difference in return). This is because PBR requires utilities to bear new risk. This is the implication of "performance-based" policies; the utility must take new risk (e.g., by applying new technologies, or redesigning processes) in order to increase its performance. A below-market allowed rate of return, combined with a PBR that exposes the utility to new risk, still leaves the investor inadequately compensated for the amount of risk they are being asked to bear. For this reason, PBR policies must be calibrated so that they provide an appropriate risk – return balance.

B. Benefits Sharing Is Essential

There should be mechanisms for sharing gains from regulated operations with ratepayers, because to be sustainable over time, incentive policies must produce a "win-win" for customers and shareholders. There are many ways to do this. For example, the customers' share of productivity savings (however measured) can be flowed into rates annually, as a credit against next year's revenue requirement; the customers' share can be added to depreciation reserves (*i.e.*, to reduce the rate impact of new capital projects); or the customers' share can be credited at the end of a multi-year period, when costs are reviewed and rates re-set.

Note, however, that in the interest of fairness, sharing mechanisms must be designed to share both efficiency gains <u>and potential cost overages</u>. Symmetry, the balance between upside potential and downside potential, is a key requirement for incentive policies that are effective and sustainable. Without symmetry, incentives can become confiscatory in the sense that expected outcomes are losses for utility shareholders. Symmetry can be achieved without exposing customers to losses, but only if the utility retains 100 per cent of any efficiency gains.

C. The Design of Cost Performance Benchmarks Should Account for Regional Differences

Performance-based benchmarks for transmission cost are difficult to calculate accurately in the best of circumstances. In fact, little progress made to develop benchmarks for transmission utilities that are worthy of integration into a PBR mechanism. Regional differences (*e.g.*, in geography, climate, and customer density) undoubtedly produce differences in transmission costs. In order to establish benchmarks that are just and reasonable, the Commission would need to take account of such differences.

V. A Consortium that Builds New Transmission Infrastructure Should Receive the Same Incentives that All Other Public Utilities Receive for Building New Projects

The Commission has requested comments on what actions it should take in this rulemaking to encourage public power participation in new transmission projects. In EEI's view, the over-arching goal is the expansion of the nation's transmission grid and government-owned utilities may be important contributors to achieving this goal.

The NOPR asks whether the incentives applicable to transcos should be applied to a consortium involving public power formed to develop a transmission project. EEI believes that, whether public power is or is not involved, a consortium that builds new transmission infrastructure, whose costs are recovered in FERC-approved rates, should receive the same incentives that all other public utilities receive for building new projects.

At the same time, as the Commission noted, public power entities have access to certain benefits, such as access to lower cost financing, which can be helpful to construction projects. In addition to access to lower cost financing, these entities enjoy additional benefits, such as not paying income taxes and the ability to set their own rates. Therefore, the transmission rate incentives the Commission is considering in the NOPR are not applicable to these entities. Moreover, these benefits convey competitive advantages that public power entities already enjoy over Commission-jurisdictional public utilities. The Commission should not widen that gap.

There may be other actions that the Commission may take to encourage the participation of public power entities. Public utilities operating outside of RTOs and ISOs whose transmission rates include the costs of public power entities' shares of facilities should not be subject to rate cases as to the level of their own transmission revenue requirement ("TRRs") when the TRR of a non-jurisdictional participant changes due to the addition of new facilities. These public utilities should be permitted to increase their total TRR to reflect the public power entity's proposed increase, but FERC's review should be limited to only the change in the total TRR that results from the non-jurisdictional entity's increased costs. Of course, public power entities should only be permitted to include in a jurisdictional utility's rates costs that ensure that such jurisdictional utility's rates remain just and reasonable. Such determination can be made on a stand-alone basis by examining the costs of the public power entity. This would encourage joint projects in cases where the public power entity seeks to include and recover transmission costs in the rates of a jurisdictional utility.

Finally, in order to make the most efficient use of the current transmission grid, the Commission should vigorously implement FPA section 211A to ensure that government-owned utilities and electric cooperatives provide comparable open access to their transmission facilities.

VI. Utilities Require Flexibility in Determining the Appropriate Technology Application for New Transmission Projects

EEI and its members are pleased that Congress and the Commission are exploring ways to encourage the deployment of advanced transmission technologies. EEI would like to provide several comments to help the Commission ensure that appropriate technologies are selected on the basis of the benefits that will be provided to consumers.

The Commission should avoid linking incentives to a predetermined list of “advanced” technologies. Such a list would necessarily become outdated as new technologies are developed and other technologies once considered “advanced” become less so. Prescribing a list of technologies may actually provide a disincentive to the use of other worthwhile technologies that are not on the “incentives” list.

In addition, EEI believes that the Commission’s broader goal of providing an incentive for capital investment in transmission to promote reliability and reduce transmission congestion would be poorly served were the Commission to link all of the proposed transmission incentives to a requirement that an advanced technology be chosen. Generally, the incentives being considered in this proceeding should be available to all new transmission investment, not just those projects in which advanced technologies are being utilized. This will encourage capital investment in transmission while providing public utilities flexibility to choose technologies that provide the most benefits to consumers, as measured by increased reliability and reduced congestion, without encouraging the choice of unduly risky technologies simply for the sake of using an advanced technology. The use of advanced technologies should be an option, rather than a requirement.

To encourage innovative use of technologies, the Commission should be open to requests for special ROE adders for the application of advanced technologies on a case-by-case basis. There may be instances when the use of an advanced technology would provide particular benefits that cannot be achieved in the same measure from other technologies; yet the increased degree of risk in deploying a technology that may not be as fully tested provides a disincentive to invest in that technology. In these cases, an additional financial incentive may be necessary to ensure that the project utilizing the advanced technology is able to move forward. We encourage the Commission to provide for such special incentives, in the form of an ROE adder that is sufficient to balance the increased risks for such projects.

Because the selection of technologies for a project, including a discussion of alternate technologies that were considered but not chosen, will appropriately occur during planning, siting, or when a prudence review of the project is undertaken, EEI believes that the Commission should not require a separate technology statement in applications for incentive-based rate, as this would be duplicative and burdensome to applicants.

VII. The Commission's Suspension Policy Should Be Consistent with Its Goal of Promoting Greater Capital Investment in New Transmission Capacity

In the NOPR, the Commission also requested comments on additional provisions that would accomplish the transmission investment objectives of the Act. EEI believes that in some cases, the Commission's current electric rate suspension policy, as articulated in *West Texas Utilities Co*., 18 FERC ¶ 61,189 (1982) ("West Texas"), and the Commission's subsequent application thereof, can act as a hindrance to transmission investment. The Commission has considerable discretion in determining the length of the suspension period applicable to a rate increase. Section 205(e) of the FPA allows the Commission to suspend rate schedules "not for a longer period than five months . . . ." 16 U.S.C. § 824d (e). Under the principles set forth in West Texas, and its progeny, the Commission's policy is to impose the maximum five month suspension when the Commission determines that more than ten percent of the proposed rate increase may be excessive. *See Xcel Energy Serv., Inc.*, 111 FERC ¶ 61,084, at P 15 (2005); *West Texas*, at 61,375. The Commission claims it determines whether rates are excessive based on a preliminary analysis "that is a rough, first-cut review performed within a statutorily-mandated limited time (typically within sixty days) on the basis of then-available information." [23] The Commission refuses to even discuss this analysis because doing so "would involve an inappropriate prejudgment on the merits of the issues being set for hearing and settlement judge procedures."[24] Although the Commission does not reveal anything about this rough-cut analysis, the analysis typically results in a five-month suspension when the rate increase is large (as a percentage of existing rates) or vociferously protested. *See, e.g., Puget Sound Energy, Inc.*, 81 FERC ¶61,268, at 62,321 (1997) (imposing a five month suspension on a rate increase of only $880,000).[25] It should be noted, however, that virtually all transmission rate cases involve large rate increases because utilities are hesitant to file such resource-consuming cases unless there has been a significant change in their circumstances. Hence, utilities often delay filing

[23] *Southern California Edison Co.*, 112 FERC ¶ 61,045 at P 16 (2005).
[24] *Id.*
[25] Notably, one of the factors the Commission uses in determining whether the utility's proposed rates are excessive is the pleadings or protests submitted in response to the rate filings. *See Xcel Energy Serv., Inc.*, 111 FERC at P 15. Protesters in a rate case, however, will always have a strong incentive to argue that a utility's proposed rates are excessive, and this may be one reason that the Commission generally imposes the maximum suspension.

rate cases until they have made very significant transmission investments, and almost inevitably, most transmission rate cases are protested vigorously due to their typically broad impact.

Furthermore, in practice, EEI believes that the Commission, in most cases, imposes the full five month suspensions on utilities' transmission revenue rate filings. This almost routine imposition of a five month suspension of rates serves as a strong disincentive to transmission providers to construct new transmission infrastructure. Delaying the effective date of rates forces a utility to absorb the costs associated with the new facilities during the suspension period, thereby effectively reducing that utility's return on equity. In many cases, the negative rate impact of such lengthy suspensions may far outweigh the positive impact of the various affirmative incentives that are being considered in this NOPR. These negative impacts undermine the very objectives Congress and the Commission have attempted to achieve with those incentives.

For example, the Commission recently issued an order in SCE's transmission owner rate case imposing a five month suspension of SCE's proposed rates.[26] The Commission's order contained no discussion concerning why a five month suspension was appropriate other than to state that its "preliminary analysis indicates that [SCE]'s proposed rate increases may be substantially excessive."[27] As SCE noted in its filing letter, this five month suspension is equivalent to a reduction of SCE's proposed ROE by 258 basis points.[28] A decrease of this magnitude of a utility's ROE obviates any benefit that ROE adders and other incentives provide. This result provides a strong disincentive

[26] *Southern California Edison Co.*, 114 FERC ¶ 61,018 at P 14.
[27] *Id.*
[28] *See* Filing Letter from Ellen A. Berman to Magalie Roman Salas, November 10, 2005, Docket. ER06-186-000, at 9-10.

for a utility to invest in transmission infrastructure in the future, especially when it is earning a much higher effective rate of return on non-transmission facilities.

Additionally, EEI believes the practice of routinely imposing a five month suspension is not necessary to protect customers since a utility's customers already are sufficiently protected because any rate increase authorized by the Commission can be made subject to refund, which would be paid with interest. Thus, if the Commission ultimately finds that a utility's proposed rates are too high, its customers will be made whole.

EEI believes that the Commission's current suspension policy is punitive and discourages the construction of critical transmission improvements. The Commission should revisit its suspension policy in its Final Rule. Consistent with the Commission's goal of promoting greater capital investment in electric transmission, the Commission should allow timely rate relief for utilities' new transmission investment to avoid penalizing utilities for constructing significant new transmission facilities.

VIII. EEI Encourages the Commission Not to Impose the Proposed New Annual Reporting Requirement

In this rulemaking, the Commission has proposed to require public utilities annually to report their actual and planned capital spending on electric transmission projects and, in addition, to provide detailed information on each facility involved, using a proposed new Form X. However, the Commission has not provided adequate justification for this new data collection, as required by the Paperwork Reduction Act [29] –

[29] Under the Paperwork Reduction Act, 44 U.S.C. sections 3501 *et seq*., the Commission along with all other federal agencies is directed to ensure that it minimizes the reporting and information collection burdens it imposes on the regulated community. To meet this responsibility, agencies focus on such issues

especially given that the Commission already collects information on utility transmission investment and planning in the existing FERC Forms 1, 714, and 715 – nor has the Commission demonstrated the need to make the information collection mandatory. Furthermore, the collection of such information, in particular relating to planned facilities, poses a number of serious concerns.

Information on planned new transmission facilities is necessarily uncertain, given all the federal, state, and local regulatory approvals that are required to site the facilities (including rate, land use, and environmental approvals) and given all the lending and business decisions involved. To require companies to report such information is to invite inappropriate reliance on the information by the Commission, state commissions, and the public, who may expect the plans to be implemented without regard to the regulatory approvals and applicant and market decisions involved. Furthermore, reporting information on planned future facilities can lead to unnecessary opposition that might not occur with a proper public siting process, and it can lead to speculation in land use fees that can harm the applicant's customers. Also, reporting on planned new facilities can give terrorists or others who would disrupt the electric grid a roadmap to areas where existing facilities may be stressed, helping to target those areas.

Given these negative consequences of collecting such information, EEI encourages the Commission not to impose the proposed new reporting requirement. Instead, EEI encourages the Commission simply to monitor the number of applications for new transmission facilities that are filed, the magnitude of facilities involved, and the incentives sought – this will give the most accurate measure of the effectiveness of the

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as the need for the information, including whether it is necessary for performance of agency functions, the burden involved in reporting it, and ways to avoid or minimize the burden.

proposed incentives at promoting transmission investment over time. At most, if the Commission desires additional information on actual expenditures beyond what is available in the FERC Form 1, EEI encourages the Commission to rely on annual aggregate transmission investment information that EEI has provided to the Commission and can continue collecting for the Commission's benefit.[30]

A. The Information the Commission Proposes to Collect Is Not Needed to Determine the Effectiveness of the Proposed Incentives

The Commission states that it is imposing the new data collection requirement in part to provide a basis for determining the effectiveness of the proposed incentives. *See* NOPR at P 49. However, it is not clear how facility-level data on planned transmission investment would be helpful in gauging the effectiveness of the Commission's proposed incentives rule, in particular because the Commission has correctly proposed incentives that are not directly linked to any one type of facility, upgrade, or technology, but must be requested by an applicant case-by-case. In this setting, the only accurate measure of the effectiveness of the incentives is how many applications are filed in reliance on the incentives – information best gleaned from the applications directly.

Thus, in its proposed reporting requirement, the Commission is clearly asking for a level of detail that falls well outside the scope of its proposed incentives rule. Instead, EEI believes that the best indicator to gauge the new rule's effectiveness will be the number of requests the Commission receives for incentive treatment and the number of

[30] On May 4, 2005, EEI submitted to the Commission the *EEI Survey of Transmission Investment.* Docket No. AD05-5-000.

approvals the Commission grants. The Commission obtains this information directly from its own files without imposing additional reporting requirements on public utilities.

B. The Information the Commission Proposes to Collect Is Not Needed to Assess the State of Transmission Investment

The Commission also says that it is imposing the new annual reporting requirements to provide the Commission an accurate assessment of the state of the industry with respect to transmission investment. *See* NOPR at P 49. However, the Commission already collects information from each public utility on the utility's investment in transmission infrastructure in FERC Form 1 and on the transmission system in FERC Forms 714 and 715. Moreover, RTO and ISO planning processes in some regions provide yet another rich source of data on transmission investment. EEI believes that this information, together with applications the Commission will receive in the future to obtain incentives under the current rulemaking, will give the Commission ample information for monitoring transmission infrastructure and investment without the need for the proposed new data collection. Again, if the Commission wants additional information, EEI offers to continue to collect and to provide the Commission with aggregated transmission investment information.[31]

C. The Potential Negative Consequences of Imposing the Proposed Mandatory Reporting Data Outweigh the Benefit that This Information Would Provide

Many details of planned investment at the individual facility or project level are necessarily subject to change, until a utility or other entity has completed the complex

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[31] *EEI Survey of Transmission Investment* filed with the Commission on May 4, 2005, in Docket No. AD05-5-000.

review and siting process. As the Commission is aware, planning to construct an entirely new transmission project and actually seeing the project sited and built are two very different things. Many factors outside of the control of the transmission owner may come into play to modify or derail a well planned transmission project. For this reason, collecting information on investment in specific facilities, in particular planned facilities, would not provide the public with an accurate assessment of future transmission investment. But requiring companies to provide information at this level would build expectations among regulators, market stakeholders, investors, consumers, and others who might inappropriately rely on the information. This would present reporting companies with a serious concern about potential obligations and liability stemming from such mis-reliance, presenting the companies with a risk that outweighs the benefit of such reporting. Moreover, given the potential for mis-reliance on the information, companies might feel practically compelled to frequently update their reports to the Commission as facility and project level plans evolve, substantially further increasing the reporting burden. In addition, reporting on potential future investments in specific transmission infrastructure could lead to real estate price escalation in the vicinity of identified potential new projects and other negative effects, again outweighing any potential benefits of such detailed reporting. Given the risks and burdens associated with the new reporting requirements, the Commission should not impose these requirements. Instead, it should rely on existing reporting requirements combined with the additional information it will receive from the applications for incentives under the new rule.

IX. Whatever Data the Commission Does Collect Should Be Collected from All Transmission Providers and Should Be Afforded Appropriate Confidentiality Protection

A. The Commission Should Require Non-Jurisdictional Utilities to Provide the Same Level of Information Collected From Jurisdictional Utilities

All transmission providers – including municipalities and electric cooperatives – should be required to provide the same types of information on their transmission infrastructure and investment to the Commission.[32] EEI bases this argument on both competitive and common sense grounds. The Commission justifies its collection of data on transmission as a basis for determining the "effectiveness" of the proposed incentives as well as to gain an "accurate assessment of the industry with respect to transmission investment." *See* NOPR at P 49. However, without collecting the information from all transmission providers, the Commission's assessment based on the collected information would be incomplete. Approximately 30 percent of the nation's transmission lines are owned and/or operated by public power entities.

For example, in the Western region of the U.S., public utility transmission systems are highly integrated with those of other transmission providers, many of which are large non-"public utilities" as defined in the FPA. Moreover, because such non-public utilities make up a significant segment of the nation's transmission system in some regions, any data the Commission might compel from public utilities would likely be misleading in the absence of similar data from non-jurisdictional entities. Without gathering information from all transmission providers, the Commission would not compile sufficiently reliable, complete, and accurate information to form the basis for any

[32] The Commission has the authority to request such information under FPA section 311, 16 U.S.C. 825j.

meaningful assessment of the proposed transmission incentives or the state of the U.S. transmission investment in general.

B. The Commission Should Provide Appropriate Confidentiality Protection for Information it Does Collect

As the Commission has recognized in the context of its final rule on Critical Energy Infrastructure Information ("CEII"), 68 Fed. Reg. 9857 (Mar. 3, 2003), the Commission has the authority to protect sensitive information from public disclosure under the Freedom of Information Act ("FOIA") and other applicable information reporting and disclosure laws. EEI appreciates the Commission having evaluated the need for confidentiality from a security perspective in that rule.

Since the information that the Commission proposes to request in this rulemaking (1) clearly relates to the production, generation, transmission, or distribution of energy, (2) could be useful to a person planning an attack on critical infrastructure, and (3) gives strategic information beyond the location of the critical infrastructure, EEI strongly urges the Commission to afford the information CEII treatment.

EEI also encourages the Commission to perform a similar evaluation of the proposed information as to the need for confidentiality of selected company information from a commercial perspective, recognizing that the release of commercially sensitive information can damage a company's operations just as significantly as physical damage being addressed in the CEII context. The Commission should treat company-specific and project-specific information as confidential, commercially sensitive data. EEI requests that the Commission provide confidential treatment for the commercially and financially sensitive information that may be contained in any information the Commission may elect to collect under a final rule in this proceeding.

CONCLUSION

For the foregoing reasons**,** EEI respectfully requests that the Commission consider these comments and ensure that any future Commission action ordered as a result of this proceeding is consistent with the points discussed above. If the Commission has any questions relating to these comments, please contact either me, Russell Tucker at (202) 508-5519, Ed Comer at (202) 508-5615, or Henri Bartholomot at (202) 508-5622.

Respectfully submitted

- signature -

David K. Owens
Executive Vice President,
Business Operations Group
Edison Electric Institute
701 Pennsylvania Avenue, N.W.
Washington, D.C. 20004
(202) 508-5000

Dated: January 11, 2006

<u>Appendix A</u>

EEI Principles on Transmission Investment

EDISON ELECTRIC
INSTITUTE

March 17, 2005

EEI Principles on Transmission Investment

Effective Wholesale Competition Needs a Robust, Reliable and Cost-Effective Transmission Infrastructure

Greater competition in electricity markets is expanding the use of the nation's electric transmission grid. Built originally to serve existing and future loads, interconnect neighboring utilities, and support reliability, the grid also is now being used to support a larger number of wholesale transactions across regions. EEI's members continue to actively invest in the transmission system in order to meet these needs.

The Federal Energy Regulatory Commission has raised concerns about whether integrated electric utilities are building transmission facilities. Historical and projected data demonstrates that both integrated companies and stand-alone transmission companies are making increasing investments in transmission. Reversing a trend of declining transmission investment, from 1999 to 2003 annual transmission investment by shareholder-owned utilities increased 12 percent annually and totaled nearly $18 billion over the period. From 2004-2008, preliminary data indicates that utilities have invested or are planning to invest $28 billion, a 60 percent increase over the earlier period.

Shareholder-owned utilities will continue to build transmission facilities for which they can obtain cost-recovery. However, existing impediments continue to frustrate and delay transmission investment. Federal and state regulatory and legislative policies should be aimed at eliminating these impediments. This will bolster efforts to build more transmission in the future, which in turn, will enhance local, regional and inter-regional wholesale electricity markets. These policies are outlined below:

Eliminating Impediments, Providing Regulatory Certainty and Cost Recovery, and Facilitating Transmission Investment

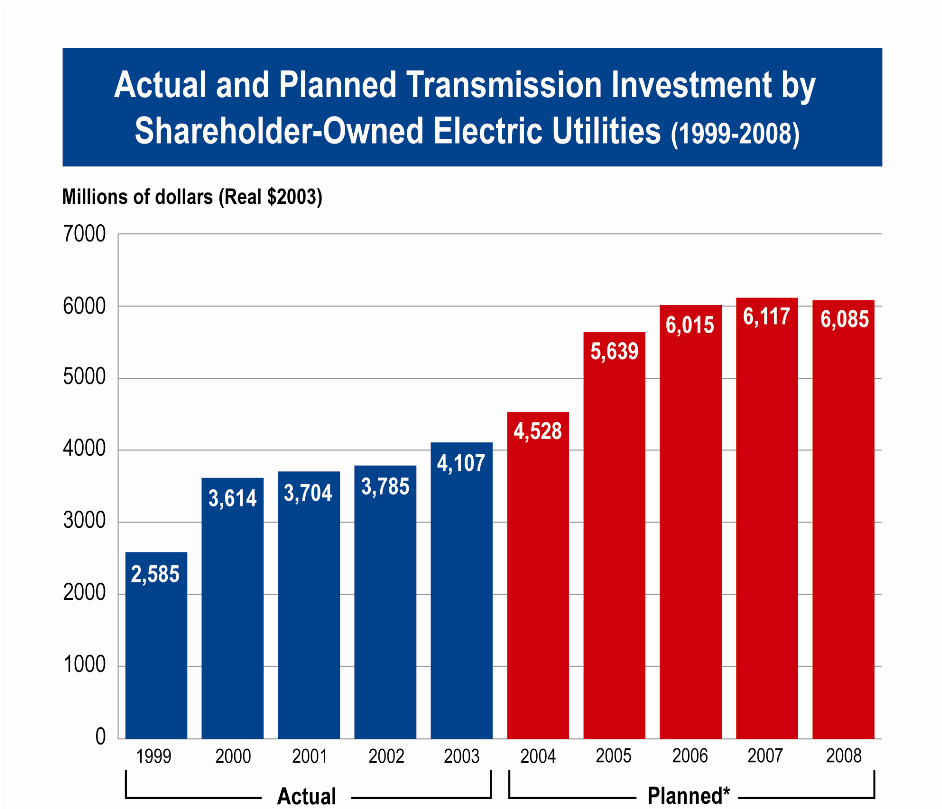
1. State and federal policy should eliminate regulatory impediments and provide regulatory certainty, particularly with respect to attractive returns, incentives, cost allocation and cost recovery, in order to raise the capital necessary to construct needed, cost-effective transmission facilities.
2. Transmission pricing should (a) allow for cost recovery of fixed and variable costs and a reasonable return on transmission investment, (b) ensure, to the extent practicable, that cost responsibility follows cost causation, (c) minimize the potential for cost shifting, (d) permit the recovery of all prudently incurred transition costs, and (e) promote efficient siting of new transmission and generation facilities.
3. Conflicting federal and state regulatory policies can result in unrecoverable, trapped costs. FERC and the states must ensure that the necessary regulatory mechanisms are in place to allow for the full recovery of all prudently incurred costs and the avoidance of trapped costs.

4. FERC and the states should allow full recovery of all prudently incurred costs to design, study, pre-certify, and permit transmission facilities. FERC should amend its rules to allow full recovery of the prudently-incurred costs of abandoned transmission projects.
5. FERC should allow utilities to include construction work in progress (CWIP) in rate base (in lieu of AFUDC) as this will encourage transmission construction through improved cash flow and greater rate stability.
6. FERC should allow for accelerated depreciation in ratemaking to improve financial flexibility, and promote additional transmission investment.
7. Where states require purchases of renewable resources that lack siting flexibility, FERC should allow alternative transmission pricing and cost recovery approaches to support the building of transmission facilities to help achieve state renewable resource goals.
8. FERC transmission policies should not favor one corporate structure, business model or retail regulatory model over another. Many different structures and business models can coexist in a competitive wholesale marketplace for the construction of transmission, provided there are fair rules in place for all market participants.
9. The Congress should take action to attract the capital necessary to build transmission capacity by repealing the Public Utility Holding Company Act (PUHCA), with appropriate federal and state access to books and records, and by providing the appropriate incentives in the tax code, including accelerated depreciation.

Improving Transmission Planning, Siting and Reliability

1. A regional planning process can identify cost-saving opportunities and facilitate the construction of new transmission to support robust wholesale markets and improved reliability.
2. Regional state committees (RSCs), where in existence, should facilitate the obtaining of necessary state regulatory approvals by parties seeking to build new transmission facilities that cross state boundaries or have multi-state impacts.
3. RSCs should assist in coordinating state siting activities through the use of standardized applications, joint data and studies, coordinated schedules and deadlines, and other mechanisms, where possible.
4. Regardless of whether there is an RSC in their region, states should streamline their transmission line siting processes and take regional considerations into account as appropriate.
5. FERC should have backstop siting authority if states cannot or will not act on applications to build transmission to relieve critical transmission bottlenecks and the Department of Energy (DOE) should act as lead agency to coordinate all authorizations and environmental reviews required under federal law to site transmission facilities on federal lands and to set deadlines for federal reviews.
6. All market participants should be subject to mandatory, enforceable reliability standards that are developed or approved by the North American Electric Reliability Council (NERC), with oversight and enforcement by the Federal Energy Regulatory Commission.

Shareholder-Owned Utilities Plan Substantial New Transmission Investment



The Handy-Whitman Index of Public Utility Construction Costs used to adjust for inflation from year to year. Data represents shareholder-owned electric utilities. *Planned total industry expenditures estimated from 93.5% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey as of 4/13/05. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey and FERC Form 1s.

- From 1999 to 2003, transmission investment by shareholder-owned utilities totaled nearly $18 billion.
- From 2004-2008, survey data shows that industry is planning to invest $28 billion. If realized, this would represent a 60 % increase over actual investment in the earlier period.
- Combined actual and planned investment over the 1999-2008 period increases 10% annually.
- Net book value of shareholder-owned transmission assets totaled approximately $45 billion in 2003.
- Planned investment over the 2004–2008 period is 63% of year 2003 net book value.
- Direct generator interconnection, on average, accounts for approximately 6.5% of annual transmission budgets for about one-third of respondents. About two-thirds of the respondents indicated zero dollars were budgeted for generator interconnection.

ATTACHMENT B

REPLY COMMENTS OF NORFOLK SOUTHERN RAILWAY COMPANY

STB EX PARTE NO. 722

RAILROAD REVENUE ADEQUACY

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

	)	
Promoting Transmission Investment	)	**Docket No. RM11-26-000**
Through Pricing Reform	)	
	)	

REPLY COMMENTS OF THE EDISON ELECTRIC INSTITUTE

I. INTRODUCTION

The Edison Electric Institute ("EEI") submits these reply comments in response to the comments raised in the above-captioned proceeding seeking significant changes in the Commission's policies under Order No. 679,[1] including the comments submitted February 17, 2012 by the National Association of Regulatory Utility Commissioners ("NARUC"), and the March 5, 2012 letter by a number of state commissions, agencies, attorney generals, consumer-owned utilities and non-governmental organizations (collectively referred to herein as the "Joint Commenters"). In these reply comments, EEI responds generally to the comments seeking such changes and also provides specific responses to the Joint Commenters.

II. GENERAL COMMENTS

As discussed below, the Commission should refrain from making significant changes to the existing Order No. 679 incentive rate policies based only on the unsupported statements of certain commenters that existing incentives are "overly generous" at the expense of consumers.[2]

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[1] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2007), *order on reh'g*, 119 FERC ¶61,062 (2007).

[2] *See, e.g.*, Letter of Joint Commenters at 1 (Mar. 5, 2012) ("The current incentive structure places unwarranted burdens on consumers. . ."); Letter of the National Association of Regulatory Utility Commissioners (Feb. 17, 2012) (concluding that the granting of incentive rates under the Commission's current transmission-incentive regulations

(cont…)

As EEI explained in its initial comments in this proceeding, while there are some areas of improvement that can be made to the incentives policies, the Commission should retain all of the existing incentives and not restrict their availability through this proceeding.

Restricting incentive rates would jeopardize the Commission's Congressional mandate to provide incentives to ensure that needed transmission is built. Instead, the Commission should focus on improving the current Order No. 679 policies by implementing minor changes such as providing better guidance for the application of the nexus test, treating construction work in progress ("CWIP") and abandoned plant cost recovery under general ratemaking principles, and providing more transparency in orders granting or denying incentives.[3] This approach would be consistent with the Commission's appropriate determination in Order No. 679 to avoid static policies and formulaic criteria in favor of a case-by-case approach that matches incentives to project risks through the nexus test.[4] Many commenters, including EEI, have offered useful suggestions for improving the current transmission incentives policy without placing pre-defined limits on incentives and without creating categorical exclusion of certain projects from incentives consideration.

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and policies under Order No. 679 has transferred hundreds of millions of dollars from consumers to transmission investors without any clear showing of need or benefit and Order 679 prescribes policies that are in dire need of reform.); Comments of Certain State and Consumer-Owned Entities at 16 (Sept. 12, 2011) (" . . . the broad application of overly generous transmission rate incentives has imposed unwarranted and excessive charges on consumers."); Joint Comments of the American Forest & Paper Association, et al., at 16 (Sept. 12, 2011) ("we cannot know [the effects of the incentives policies], but we do know that consumers substantially overpaid for the new transmission facilities that have been constructed."); Comments of Electricity Resource Consumers Council at 5 (Sept. 12, 2011) ("it is clear that whatever speculative benefits may have resulted from transmission incentives approved by FERC, they have been far outweighed by the excessive costs charged to rate payers.").

[3] *See* Comments of EEI, Docket No. RM11-26-000, at pp. 2-3, 14-21 (Sept. 12, 2011).

[4] *See* Order No. 679 at P 22, 24.

In response to comments submitted in this proceeding arguing for restricting incentives, EEI submits that significant changes to the Commission's policies are both unnecessary and counterproductive for the following reasons: (1) adequate returns for transmission investment continue to be needed to attract sufficient transmission investment and do not result in unjust rates; (2) the Commission's incentive policies have not burdened consumers; (3) existing planning processes adequately protect against unnecessary transmission investment; and (4) transmission developers continue to face significant risks completing projects which necessitate offsetting incentive measures.

A. Adequate Returns Are Essential to Encourage Needed Transmission Investment

The crux of the issue is what incentives, including returns on equity ("ROE") incentives, are adequate to encourage continued investment in needed transmission without being overly burdensome to consumers. Importantly, with respect to burdens on consumers, EEI emphasizes that transmission is the smallest part of a customer's bill.[5] Transmission projects receiving incentives under Order No. 679 account for only a small subset of such charges. The economic reality is that ROE incentives are necessary in many cases, as explained more fully below, to attract investment because transmission development is high risk.[6] ROE incentives can be

[5] While the transmission component may vary over time and by region, the Department of Energy ("DOE") estimates that transmission comprises eight percent of a customer's bill. *See, e.g.*, Energy Information Agency, "Major Components of U.S. Average Electric Price, 2010", *available at*: http://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices.

[6] The risks associated with transmission development are discussed at length in the original record of comments in this proceeding. *See, e.g.,* Comments of EEI at pp 9-13. (Sept. 12, 2011); Comments of American Electric Power Service Corporation at 6-8 (Sept. 12, 2011); Comments of Southern California Edison Company at 9-11 (Sept. 12, 2011); Comments of Northeast Utilities Service Co. at 9-12 (Sept. 12, 2011); Comments of Credit Suisse Securities (USA) LLC and Barclays Capital (Sept. 12, 2011); Comments of American Transmission Company LLC at 9 (Sept. 12, 2011); Comments of the PPL Companies at 3-5 (Sept. 12, 2011); Comments of MidAmerican Energy Holdings Co. at 4-5 (Sept. 12, 2011); Comments of Pepco Holdings, Inc., at 12-13 (Sept. 12, 2011).

politically unpopular, in part because the ROE is a highly visible component of a transmission project's revenue requirement that can be easily criticized out of context, while the long-term benefits and cost savings that result from transmission investments involve complex, forward-looking data that is harder to quantify.

Many commenters in this proceeding do not give full consideration to the ongoing need for new transmission infrastructure, the significant risks facing transmission developers, and the positive role the Commission's incentive policies have played in supporting new transmission investment. Instead, most of their focus has been on the purported cost burdens of new facilities. As Congress recognized in the Energy Policy Act of 2005, however, there is a great need for new transmission infrastructure in the United States. The Commission correctly found in Order No. 679 that "[t]he issue of whether there is a need for new transmission investment has been put to rest by Section 219."[7]

Congress's determination of great need for new transmission is shown not only by enactment of Section 219 through the Energy Policy Act of 2005, but by the other provisions of the Energy Policy Act of 2005 that are intended to expedite transmission planning and construction.[8] For example, Section 1221 of the Energy Policy Act of 2005 is intended to expedite the siting of interstate transmission facilities within National Interest Electric Transmission Corridors[9] and Section 368 of the Act is intended to expedite siting transmission

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[7] Order No. 679 at P 13, 19.

[8] *E.g.*, ENERGY POLICY ACT OF 2005, Pub. L. No. 109-58, 119 Stat. 594, 946 ("Subtitle B, Transmission Infrastructure Modernization").

[9] *Id*.

within corridors on federally-owned land.[10] However, the intended benefits of these provisions have not yet been realized due to litigation.

In addition to these statutory provisions, the Executive Branch departments and agencies have only recently focused on coordination activities to address challenges to developing transmission, through establishment of the interagency Rapid Response Team for Transmission, which applies only to a small number of priority projects, such as the Susquehanna-Roseland and Gateway West projects discussed herein.[11] This effort recognizes there is an urgent need to address federal permitting and siting challenges to expedite development of needed transmission and that much more needs to be done.

Due in part to the difficulties in implementing the full panoply of provisions of the Energy Policy Act of 2005 relating to transmission and the uncertain impacts of the federal agency coordination noted above, building transmission continues to be a risky endeavor. Moreover, even if these efforts were, or become, effective, the best planned facilities have been and may still get mired in litigation and/or delayed. These circumstances lead to increased risks and costs, reinforcing the need for regulatory certainty through continued application of the incentives policy.

At the same time, public policy goals, particularly those evidenced by state renewable portfolio standards and various tax incentives for renewable generation, have led to an increased need to construct new transmission facilities to connect regions rich in renewable resources to

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[10] *Id.*, 119 Stat. 594, 727.

[11] *See* Council on Environmental Quality, Interagency Rapid Response Team for Transmission, *available at*: http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission.

load. For example, renewable energy goals in California are the primary driver for Southern California Edison Company's Tehachapi transmission project. Approved in 2007 by the California Independent System Operator Corporation ("CAISO"), the Tehachapi project is estimated to accommodate a potential of 4,500 MW of renewables generation and 15.2 TWh of energy per year, approximately one-third of the total needed in the CAISO's area to meet the state's 33% Renewable Portfolio Standard goal.[12] Moreover, current trends of increased reliance upon natural gas as a generation fuel, closures of coal plants necessitated by Environmental Protection Agency ("EPA") regulations and other factors, and development of natural gas in new regions of the country may well lead to changes in both generation patterns and uses of the transmission system.

As stated in many of the initial comments in this proceeding,[13] in its short period of implementation, Order No. 679 has been successful in encouraging transmission investment, and it is vital that this policy continue to do so. Now is not the time to dramatically change course. While EEI believes minor improvements to the Commission's transmission incentive policy can be made to fulfill Congress's Section 219 statutory mandate, meet emerging public policy objectives, and protect the continued reliability of the nation's electric grid through a robust transmission system, the Commission must retain the overall flexibility to match appropriate incentive rate treatment to transmission development risk on a case-by-case basis. A contrary

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[12] *See* CAISO's 2011 Annual State of the Grid Report at 17 *available at*: http://www.caiso.com/Documents/2011AnnualStateoftheGrid-20110817web.pdf

[13] *See, e.g.*, comments of Midwest ISO Transmission Owners, New England Transmission Owners, LS Power Transmission, LLC, Atlantic Power Corporation, Enbridge Inc., Southwestern Power Group., and Energy Investors Fund filed in Docket No. RM11-26-000.

approach risks jeopardizing the progress that has been made since the Commission implemented Order No. 679.

In this proceeding, no party has submitted evidence suggesting that the existing transmission infrastructure has suddenly become adequate and that new infrastructure should not continue to be encouraged. The need still exists, as demonstrated by a 2008 Brattle Group study of the state of transmission facilities in the United States, which concluded that an additional $300 billion in transmission investment is needed over the next twenty years.[14] More recently, in April 2012, the American Society of Civil Engineers ("ASCE") issued a report that attempted to quantify the estimated future investments in transmission.[15] As the ASCE Report acknowledges, transmission investment has been steadily increasing under the current incentives policies.[16] Nevertheless, the ASCE Report projects a transmission investment gap of approximately $112 billion by 2040.[17] In addition, the impact of compliance with the EPA's evolving clean air and water regulations will drive more capital investment, including additional investment in transmission.[18] Order No. 1000 also focuses on the need for additional transmission to meet

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[14] *See*, The Brattle Group, "Transforming America's Power Industry: The Investment Challenge 2010-2030" (November 2008), Executive Summary page xi, and pages 37-40, *available at:* http://www.eei.org/ourissues/finance/Documents/Transforming_Americas_Power_Industry.pdf.

[15] AMERICAN SOCIETY OF CIVIL ENGINEERS, FAILURE TO ACT: THE ECONOMIC IMPACT OF CURRENT INVESTMENT TRENDS IN ELECTRICITY INFRASTRUCTURE (April 2012) ("ASCE Report"), *available at*: http://www.asce.org/uploadedFiles/Infrastructure/Failure_to_Act/SCE41%20report_Final-lores.pdf

[16] *See id*. at 33 ("the planned investment in transmission infrastructure picked up significantly starting in the 2006-10 period."). The ASCE Report also notes the contributions of FERC's incentive rate policies on transmission investment, finding that "incentives provided by FERC and supported by mandates or planning studies by states and regional transmission organizations have led to an uptick in investment planning." *See id*. at 32.

[17] *See id*. at 34.

[18] Generator retirements may necessitate transmission upgrades. Indeed, on May 17, 2012, the PJM board of directors approved nearly $2 billion in transmission upgrades aimed at ensuring reliable electric service in the wake of recently announced power plant retirements. *See* Platts, "PJM board approves nearly $2 billion in grid upgrades," *available at*: http://www.platts.com/RSSFeedDetailedNews/RSSFeed/ElectricPower/6309301. Relevant to the issues in this proceeding, the EPA recently has proposed four sets of regulations that collectively impose more

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state and federal public policy initiatives as well as evolving reliability and cyber security requirements.

To meet these burgeoning capital needs, adequate returns on investments in transmission, including appropriate incentives, must be set with a long-term perspective that will provide regulatory certainty and continuity throughout both the typical five to seven year project construction timeline and the 30-40 year life of the transmission asset. The bottom line is that while the past five years have been a good start, the Congressional goal of meeting the country's long-term transmission requirements will not be achieved if the Commission retreats from awarding reasonable incentives for eligible new transmission projects.

The Commission's incentives policy is working. EEI members' investment in new transmission facilities and upgrades in 2010 was $10.2 billion, which is approximately thirty-five

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stringent requirements on generators, and the regulations would require generator owners to determine whether to retrofit their units with environmental controls or retire them. These regulations are: (i) Cooling Water Intake Structures (http://water.epa.gov/lawsregs/ lawsguidance/cwa/316b/index.cfm); (ii) Coal Combustion Residuals (http://www.epa.gov/osw/nonhaz/ industrial/special/fossil/ccr-rule/index.htm); (iii) Cross State Air Pollution Rule (http://www.epa.gov/airtransport/); and (iv) Mercury and Air Toxics Standards (http://www.epa.gov/ttn/atw/utility/utilitypg.html). As units are retired due to these regulations, transmission solutions in some situations will be required in order to maintain reliability. NERC noted in a report released in November 2011 that the regulations are expected to result in generator retirements and cause a need for additional transmission investment:

> As replacement generation is constructed, new transmission infrastructure may be required to interconnect these new generation resources. Transmission impacts need to be assessed and also given ample time for preventative measures to be put in place. Additionally, existing generation resources may not be deliverable to due to transmission limitations in the existing system and enhancements may be needed in order to support firm and reliable transmission service. *See* NERC *2011 Long-Term Reliability Assessment* at 75 (Nov. 2011), *available at*: http://www.nerc.com/files/2011LTRA_Final.pdf.

Studies of the impacts of the EPA regulations have been performed. For example, a recent Midwest Independent System Operator (MISO) study projects that between 2,919 MW and 12,652 MW of coal plant capacity would be at-risk for retirement due to the EPA regulations and that, over a twenty-year planning period, between $580 million and $880 million of additional transmission system upgrades could be required to maintain system reliability. *See* Presentation, *EPA Impact Analysis: Impacts from the EPA Regulations on MISO*, pp. 5-6 (October 2011) *available at*: https://www.midwestiso.org/Library/Repository/Study/MISO%20EPA%20Impact%20Analysis.pdf.

percent more than their new investments in 2005 ($7.5 billion), immediately prior to issuance of Order No. 679. Furthermore, EEI's 2012 Transmission Projects: At A Glance report describes over 100 transmission projects completed, or expected to be completed from 2011 through 2022, totaling approximately $64 billion (nominal dollars). While this report is not a comprehensive compilation of all transmission projects and transmission investments being undertaken by EEI's members, the sampling of projects described captures a wide variety of project types. To provide a sense of the regional nature of the facilities and the expected benefits of these projects, sixty-six percent of the projects are interstate transmission projects, seventy-seven percent of the projects facilitate the integration of renewable resources, and sixty-five percent of the projects have multiple utility participants.[19]

Despite the progress that has been made, there are no assurances that transmission will continue to be constructed at sufficient levels. As the ASCE Report and Brattle Group study underscore, significant transmission investment is needed in coming years. Furthermore, transmission investment is not immune to current economic conditions. EEI's data shows a slight decrease in 2013-2014 planned transmission investment level compared to the 2012 level.[20] However, transmission incentives are thirty to forty year assets, and incentives policy accordingly should not fluctuate with market conditions. EEI is concerned that restricting the Commission's current incentives policies could make the decrease in transmission investment observed in its data worse in the long run.

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[19] Edison Electric Institute, "Transmission Projects: At A Glance" (May 2012), *available at*: http://www.eei.org/ourissues/ElectricityTransmission/Documents/Trans_Project_lowres.pdf.

[20] *See* Edison Electric Institute, "Actual and Planned Transmission Investment By Shareholder-Owned Utilities (2005-2014)" (Sept. 2011), *available at:* http://www.eei.org/ourissues/ElectricityTransmission/Documents/bar_Transmission Investment.pdf.

B. The Commission's Incentives Policy Has Not Burdened Consumers

Parties seeking significant reforms of the Commission's incentive policy in this proceeding discount the fact that there are adequate protections existing to safeguard consumers against unreasonable rates. Existing qualifying requirements for incentive treatment are sufficiently rigorous to appropriately determine projects that satisfy FPA Section 219. Rates that include Order No. 679 incentives are cost-based, subject to Commission review to determine whether they are just and reasonable. Pursuant to Commission regulations, in order to receive incentive rate treatment pursuant to Order No. 679 for a particular project (or group of projects), an applicant must show: (1) that the facilities for which it seeks incentives satisfy the requirements of FPA Section 219, *i.e.*, they either ensure reliability or reduce the cost of delivered power by reducing congestion; (2) that the total package of incentives is tailored to address the demonstrable risks or challenges faced by the applicant in undertaking the project (the "nexus" test); and (3) that the resulting rates are just and reasonable.[21] Rates that are in effect may also be audited and further reviewed if necessary.[22] On this issue, EEI supports transparent review of projected rate impacts when the Commission evaluates a request for incentives.

EEI urges the Commission to be cautious in considering arguments that incentives—particularly ROE incentives—are overly generous. Little in the way of concrete support for such arguments has been provided. On the other hand, placing excessive restrictions on incentives could impair needed transmission investment to the detriment of consumers. The nexus test,

[21] *See* 18 C.F.R. § 35.35(d).

[22] Pursuant to FPA Section 206, 16 U.S.C. § 824e, the Commission can may initiate a Section 206 review of transmission rates on its own initiative or pursuant to a complaint filing.

properly applied, can continue to ensure that transmission incentives, including ROE incentives, are appropriate and commensurate with actual development risks. In addition, the resulting rates produced after application of incentives must always be established as just and reasonable, which includes an assessment of whether the overall ROE inclusive of any incentive adder is within the zone of reasonableness, as established by Commission precedent.

Parties seeking reform of the Commission's incentive policies in this proceeding also give little consideration to the actual benefits to consumers of the transmission improvements that Congress intended to incentivize and that are now being built.[23] Among other things, by providing access to lower cost and more diverse generation resources, transmission investments provide long-term service and reliability benefits, help achieve public policy goals and can actually lower the energy component of a consumer's bill.[24] Though the benefits of some transmission projects may not be easily quantifiable, the sample of projects included in the table below demonstrate that transmission investments can return net benefits for consumers in a short amount of time:

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[23] For example, in a May 11, 2012 letter to the Commission in this proceeding, Representative Edward J. Markey notes his concern that New England consumers are paying excessive charges due to the Commission's incentives policy, but Rep. Markey does not acknowledge the benefits received from new transmission projects in New England. *See* Letter from Representative Edward Markey to Chairman John Wellinghoff, Docket No. RM11-26-000 (May 11, 2012). ISO New England Inc.'s ("ISO-NE") 2003 Regional system plan makes it clear that the New England system in 2003 had reached or surpassed its design limits, creating a variety of reliability issues across New England. New England has been successful in making necessary investments in recent years, and the most recent ISO-NE 2011 Regional plan states that "The transmission system, which for decades saw little investment, has been upgraded to better serve the region's load." ISO New England Inc., 2011 Regional System Plan at 1 (Oct. 11, 2011) ("RSP"), *available at*: http://www.iso-ne.com/trans/rsp/2011/index.html. It also shows that congestion-related costs have decreased. *Id*. at 5 ("In 2010, system-wide congestion-related costs totaled approximately $37 million, and payments for generators in "must-run" situations…totaled $9 million. These represent significant reductions from 2008 when congestion totaled $273 million and generator payments for "must-run" situations totaled $212 million").

[24] Unlike transmission, which makes up a small fraction of the overall electric customer bill, the energy component is the largest percentage, typically over fifty percent. *See, e.g.*, Energy Information Agency, "Major Components of U.S. Average Electric Price, 2010", *available at*: http://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices.

Project Name	Estimated Annual Cost (Millions)[25]	Estimated Benefits (Millions)
TrAIL Project (TrAILCo)	$200	**Annual:**[26] $1,000
Phase I 345 kV (NSTAR)	$44	**Annual:**[27] $260
Tallgrass/Prairie Wind (OGE, Westar and Electric Transmission America)	$220	**Annual:**[28] $628 - $728
Tehachapi (SoCal Edison)	$500	Accommodate 4,500 MW of renewables, approximately 1/3 of California's 33% RPS[29]
Pioneer Project (Pioneer Transmission, LLC)	$220	4,000 MW capacity will accommodate thousands of MWs of new wind generation.[30]

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[25] These figures are intended for illustrative purposes and are derived by applying a hypothetical 20 percent carrying charge to the total estimated cost of the project. The 20 percent carrying charge is utilized to arrive at a conservative estimate of the total costs. For an explanation and example of a carrying charge, *see* Fair Pricing Group Comments, Docket No. EL05-121-006, Exh. FPG-100 (May 13, 2010), *available at*: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12356739.

[26] *See,* FERC Office of Enforcement, *2011 State of the Markets Report* (Apr. 19, 2012), *available at*: http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/som-rpt-2011.pdf. In addition, it appears that the TrAIL project entering service in 2011 (along with some other transmission improvements) will reduce congestion costs by about $1 billion in 2012. *See,* Figure 13.2 of the 2010 PJM RTEP Plan, *available at*: http://www.pjm.com/documents/reports/rtep-report/~/media/documents/reports/2010-rtep/2010-section13.ashx.

[27] Electricity Transmission Infrastructure Development In New England: *Value Through Reliability, Economic and Environmental Benefits*, Pages 3-4 (December 2007), *available at*: http://www.newenglandenergyalliance.org/downloads/New%20England%20Transmission%20Paper.pdf

[28] Tallgrass Transmission, LLC, Request for Incentives, Docket Nos. ER09-35-000, *et al*., Exh. TGT-103 at 10 (Oct. 3, 2008), *available at*: http://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=11823413

[29] California Independent System Operator Corp., 2011 Annual State of the Grid Report, at 17 (Aug. 17, 2011), *available at*: http://www.caiso.com/Documents/2011AnnualStateoftheGrid-20110817web.pdf

[30] Pioneer Transmission, LLC, Request for Incentives, Docket No. ER09-75, Exh. PNR-200 at 16 (Oct. 15, 2008), *available at*: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=11832073.

EEI emphasizes that the benefits highlighted in the preceding table are not necessarily the total benefits provided by these projects. These projects may also provide benefits of assuring system reliability, providing congestion relief, reducing capacity costs, or facilitating the implementation of public policy goals.[31] Transmission is a key component of electricity supply, enabling the movement of energy in bulk from geographically diverse resources to load. Importantly, as noted above, transmission costs are the smallest part of a customer's bill compared to production and distribution costs. For transmission projects that reduce capacity costs, there may be significant production cost savings. Such savings, along with other benefits, more than offset the cost of a transmission project in most cases.

C. Existing Planning Processes Adequately Protect Against Unnecessary Transmission Investment

Current planning policies under Order No. 890[32] and the requirements of Order No. 1000[33] provide transparency for stakeholders and ensure that the transmission projects advanced through planning processes are necessary and beneficial. As the Commission explained in developing reforms to planning processes in Order No. 890-A, "[t]ransmission planning is critical because it is the means by which customers consider and access new sources of energy and have an opportunity to explore the feasibility of non-transmission alternatives."[34] Thus, regional planning processes and coordinated interregional planning must analyze projects in the

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[31] *See* note 25, *supra*, *2011 State of the Markets Report* at n.37.

[32] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 471, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[33] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, 139 FERC ¶ 61,132 (2012).

[34] Order No. 890-A at P 4.

context of alternatives and help determine whether a given project is needed, whether it is a cost-effective solution, and whether it is the right solution amidst the range of options. At the same time, new transmission projects are subjected to additional reviews as part of state integrated resource planning, Commission and state prudence reviews, and siting processes.

These are adequate consumer protections. While some commenters suggest that there is a need to better protect consumers,[35] no harm or material burden to consumers from new transmission has been specifically identified that also reasonably accounts for the benefits to consumers from new transmission. Moreover, as the projections such as the Brattle Group report show, what is needed to truly protect consumers is more transmission, not less.[36] When evaluated in the context of these planning processes, the concerns that the Commission's transmission incentives policies will lead to burdensome and unnecessary transmission investment are not justifiable.

On the contrary, the Commission's existing review over rates that include incentives and the open and transparent transmission planning processes ensure that necessary transmission is built at just and reasonable rates. As a result of the Commission's transmission planning reforms, transmission projects are approved in regional planning processes that must take into account alternatives that can meet the region's needs on a more cost effective or efficient basis. At the same time, however, the regional planning processes must be able to address needs that require higher risk transmission solutions where no other alternative would suffice. In the experience of EEI's members, the Commission's incentive policies are fundamental to incenting

[35] *See* note 2, *supra*.

[36] *See* section I.A, *supra*.

the construction of such solutions. Importantly, while these planning processes protect consumers against unnecessary costs, they do not protect transmission developers against risks of costly litigation, damage to reputation, and costly delays in getting permits approved.

D. Transmission Developers Continue to Face Significant Risks in Completing Projects Which Warrant Offsetting Incentive Measures

Transmission providers continue to face significant risks in completing a new transmission project, particularly in the siting process, as several examples can illustrate. These risks include delays in siting approvals by federal agencies and litigation over permitting or siting. These events raise project costs, making projects more risky. In addition, project delays tie up capital that is committed to fund the project, constraining the availability of capital for other utility needs.

One example of risks faced in project development is provided by the Trans-Allegheny Interstate Line ("TrAIL") project, completed in 2011. The TrAIL project was approved in the PJM Regional Transmission Expansion Plan ("RTEP") in 2006. The project was labeled a reliability project, but also offered other benefits when coupled with other PJM transmission upgrades.[37] TrAIL sponsors faced enormous challenges in the siting process, including considerable local opposition. The siting process for the TrAIL project was complex, as the

[37] *See* table, *supra*, Section I.B. Moreover, as reported in the Commission's 2011 State of the Markets presentation on April 19, 2012, congestion cost savings, a reduction in capacity costs, and enhanced system reliability and operational flexibility have been realized due to the TrAIL project. *See* FERC Office of Enforcement, *2011 State of the Markets Report* (Apr. 19, 2012), *available at*: http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/som-rpt-2011.pdf. For example, Commission Staff found that, as a result of the TrAIL project being placed in service, total congestion costs on the AP South interface and the Bedington-Black Oak interface dropped by half to $262 million in 2011. *See id.* at slide 13. As another example, the difference in capacity prices in PJM's forward capacity market between the east and west regions decreased from $100 /MW-day in 2009/2010 to zero for the 2011/2012 delivery year. *See id.*

project crossed West Virginia, Virginia, and Pennsylvania, requiring permits from each state. Securing these permits required a demonstration of need. To receive final approvals on siting, TrAIL sponsors were required to meet siting and construction challenges from over a thousand counties, cities, individuals, and environmental groups. This project required acquisition of approximately 180 miles of new right-of-way, more than eighty percent of TrAIL's approximate length of 210 miles. The project developers exercised due diligence to assure siting was done appropriately with minimal impacts.

A second example of risks is provided by the Susquehanna-Roseland project, a 500kV transmission line extending 130 miles from the Susquehanna switchyard in northern Pennsylvania to a new substation (Jefferson) and on to the Roseland substation in New Jersey. The project also includes two new transformers in northern Pennsylvania and at the Roseland station. In 2008, PJM found that the Susquehanna-Roseland project needed to be operational by 2012 to prevent overloads on existing power lines and directed Public Service Electric & Gas Company ("PSE&G") and PPL Electric Utilities Corporation ("PPL") to construct the project. Despite having received approvals from both Pennsylvania and New Jersey, delays in obtaining necessary approvals from the National Park Service due to upgrading existing facilities crossing federal land, delayed implementation of the project. The National Park Service initially estimated it would release its decision in the 2013-2014 timeframe, which could be up to six years after the project was approved in PJM's regional transmission plan. The impacts of the delays were expected to be considerable: in 2010, PJM estimated that delays would cost ratepayers approximately $160 million in 2012 and $280 million in 2013.[38] With assistance

[38] *See*, PJM 2010 Regional Transmission Expansion Plan, pp. 89, 218, 346 and 400, *available at*: http://www.pjm.com/documents/reports/rtep-report/~/media/documents/reports/2010-rtep/2010-rtep-report.ashx.

from DOE, PSE&G was able to expedite the process and obtain initial approvals from the National Park Service in March 2012. However, the National Park Service's decision is under challenge by environmental groups, including the Sierra Club. In addition, PSE&G is still working with the National Park Service to finalize a mitigation package. As a result, it is not clear when the project will be completed.

A third example of risks is PacifiCorp's Gateway West project, which has been included in the company's integrated resource plans and regional transmission planning efforts—including those of Northern Tier Transmission Group and the Western Electricity Coordinating Council—since the project's announcement in 2007. This project is part of PacifiCorp's Energy Gateway project, which will strengthen the interconnections between PacifiCorp's two control areas and provide needed reliability improvements to help maintain low-cost delivery and service reliability for network customers. Gateway West is needed to provide long-term benefits to the existing transmission system in order to relieve operating limitations, increase capacity, and improve reliability in the existing electric transmission grid, which will also result in additional high-voltage backbone transmission for efficient, flexible and diverse resource development in resource rich areas, including renewables.

PacifiCorp initiated the environmental review process under the National Environmental Policy Act for Gateway West in 2007. However, a Draft Environmental Impact Statement ("DEIS") was not issued by the Bureau of Land Management ("BLM") until July 2011—approximately two and a half years after BLM's initial target date for issuing the DEIS. Further, the DEIS was issued without an agency preferred route, injecting additional risk and complexity into the project timeline, the public involvement process, and ultimately, the timing of integrating incremental generation resources. Based on this uncertainty, the project has been delayed and is now not scheduled for completion until sometime between 2016 and 2021.

E. Conclusion

Without conclusive evidence that the Commission's incentives have resulted in burdensome costs and "overly generous" compensation for transmission developers, there is no justification to undertake the wide-reaching reforms to the existing policies that certain parties advocate. New transmission projects, particularly multi-state projects, continue to be subject to significant risks. Existing state and Commission processes, including the Commission's reforms to the transmission planning processes, provide multiple layers of review to new transmission projects and ensure that consumers are not burdened with costs for projects from which they do not benefit. However, to meet transmission needs in the coming years, it is critical that the Commission maintain the primary aspects of its existing incentives policies, including offering an incentive return for transmission developers.

III. RESPONSE TO JOINT COMMENTERS

Many of the issues raised by commenters arguing for a restriction in incentives policies are also raised in the March 5, 2012 letter filed by the Joint Commenters. EEI responds to these specific arguments below.

A. "Above-Cost" Incentives

The Joint Commenters argue that the Commission should grant-risk-reducing incentives first and award "above-cost" incentives rarely.[39] Among other things, the Joint Commenters claim that CWIP and abandoned plant incentives should be considered first where unusual risks

[39] Joint Commenters' Letter at 1.

are shown to be present, and the Joint Commenters suggest that formula rates and CWIP and abandoned plant incentives can obviate the need for an incentive ROE.[40] However, the Commission has routinely found that each of the incentives correctly serves a different purpose.[41] The Joint Commenters have not identified any changes in circumstances that would necessitate a different finding now.

The Joint Commenters' concern that incentives may be "above-cost" is misplaced. Authorizing an appropriate return for a project that has above-average risk does not amount to providing an incentive that is above cost. All incentives under Order No. 679 are cost-based and can only be implemented to the extent they result in rates that are within a zone of reasonableness, as determined by the Commission. The Commission's existing policies, including its review under FPA Section 205 of a request to recover incentives through rates, are sufficient to guard against "above cost" projects and further limitations on the types of incentives that may be offered are not needed.

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[40] *See id*. at 1-2.

[41] For example, the Commission has explained the difference between the CWIP incentive and the ROE incentive:

> [T]he CWIP incentive and ROE incentive serve two separate purposes. The inclusion of CWIP in rate base enhances cash flow, reduces interest expense, and assists utilities with financing, all of which were important to PATH given the long lead time and significant outlay of capitol associated with the Project. In contrast, a higher ROE encourages new transmission investment because it provides a longer term higher ROE after the project comes on line, only for that new investment, and makes that transmission project more attractive as an investment. *Potomac-Appalachian Transmission Highline, L.L.C.*, 133 FERC ¶ 61,152 at P 85 (2010) (*citing* Order No. 679 at P 91, 115)).

Furthermore, EEI agrees with the Commission's prior findings that a formula rate does not preclude impact eligibility for incentives recovery. As the Commission explained in *Potomac-Appalachian Transmission Highline, L.L.C.*:

> The Commission finds that PATH's use of a formula rate does not prevent PATH from receiving an incentivized ROE or other rate incentives. While a formula rate is designed to improve cash flow by providing for the timely and administratively efficient recovery of costs, the very purpose of the incentive rates is to provide additional rate assurance in order to encourage investment in the Project. *Id*. at P 88 (*citing* Order No. 679 at P 1).

B. Excluding Reliability Projects and/or Projects That Utilities Are Obligated to Build Overlooks the Development Risks of These Projects

The Joint Commenters contend that the Commission should not provide incentives for projects that a utility has a legal obligation to build or projects built to ensure compliance with reliability standards. With regard to reliability projects in particular, the Commission has already found that it is not a reasonable interpretation of FPA Section 219 to exclude them from consideration for incentives.[42] As explained by the Commission in Order No. 679, such an interpretation "would be contrary to a fundamental goal of EPAct 2005 to improve reliability of the interstate transmission grid."[43] There is no evidence in the record that would justify the Commission making a different finding now that is contrary to the Congressional mandate in FPA Section 219.

Regarding projects which a utility may be obligated to build, the recommendation of the Joint Commenters is based on a narrow view of such projects. The experience of EEI's members is that transmission investment decisions have greatly benefited from the Commission's incentive policies because utilities have been able to consider and develop transmission projects that might be deemed too risky otherwise. Although utilities have an obligation to construct transmission projects to facilitate transmission service, that obligation often can be satisfied through smaller, localized projects designed only to meet the limited need created by the service. Incentives enable consideration of higher-risk transmission projects that are regional or larger scale, would more efficiently meet multiple types of needs at once, and which offer greater long-term value for a broader base of customers.

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[42] *See* Order No. 679 at P 42.

[43] *Id*.

Concerns that transmission projects would be over-sized in such circumstances are misplaced because the projects must be tailored to satisfy specific, identified needs through the open and transparent transmission planning process established through Order No. 890, as well as satisfy federal and state prudence reviews before recovery through rates. Moreover, current Commission policy typically does not allow incentives for projects that are found to be of a "routine" nature.[44] State integrated resource planning adds a further layer of review to new projects. Thus, it would be a mistake from a policy perspective to categorically exclude projects that meet a service obligation from incentives eligibility. The Commission's existing nexus test and other policies governing the distribution of incentives to projects are more than sufficient to guard against the Joint Commenters' underlying concern.

On a fundamental level, the Joint Commenters' recommendation wrongly presumes there is no risk associated with reliability projects or projects that a utility has a legal obligation to build. In fact, of all construction risks facing a public utility transmission provider, new transmission projects are among the greatest. Transmission projects often cover significant areas and involve multiple landowners, which increases the risks of extensive efforts to obtain right-of-way, opportunities for political pressure, opposition, and litigation. Moreover, transmission line lead-time can be significantly longer than generation and distribution projects (*i.e.*, lead-times may be as much as five years or longer for transmission projects). Transmission projects may have higher development risk, over longer periods of time, and have more complex siting requirements. These considerable risks facing transmission developers are illustrated by the TrAIL, Susquehanna-to-Roseland, and Gateway West projects discussed above.

[44] *See generally* Order No. 679 at P 27, 94; Order No. 679-A at P 23; *Baltimore Gas & Elec. Co.*, 120 FERC ¶ 61,084 at P 48-55 (2007).

C. Incentives Where Lower-Cost Alternatives Are Available

The Joint Commenters argue that the Commission should not incent expensive solutions when lower-cost alternatives are available. While EEI does not disagree with the basic principle that only the most economic solution should be adopted, there is no need for the Commission to adjust its incentive rate policies in this proceeding to address the Joint Commenters' concern. First, there is no evidence presented in this proceeding that expensive solutions have been granted incentives and implemented where lower-cost alternatives were adequate substitutes.[45] Second, there are processes in place that guard against the Joint Commenters' basic concern. For example, a basic component of traditional resource planning in most, if not all States, is consideration of alternatives and a consideration of the relative economics of the approach chosen by the utility.

At a regional level, the Commission has adopted planning reforms in both Order No. 890 and Order No. 1000 that address this very concern. For example, in Order No. 890, the Commission required that transmission planning processes be established that are open to all stakeholders and that, in a transparent manner, make available the criteria, assumptions, or data underlying transmission plans.[46] These reforms encourage collaboration with stakeholders to identify the most efficient solution. The Commission also required that transmission planning

[45] Concerns that incentives for transmission may reduce the relative attractiveness of demand response, energy efficiency, and distributed generation, such as those described in Congressman Markey's May 11, 2012 letter to Chairman Wellinghoff, appear to overlook the considerable progress that has been made on these issues during the time the Order No. 679 incentives policy has been in effect. In New England, for example, as noted by ISO-NE, there are robust demand response and energy efficiency programs in place and these programs have increased by "huge strides" between 2003 and the present. *See* Comments of ISO New England Inc., Docket No. RM10-17-000 at 2 (Oct. 13, 2010).

[46] *See* Order No. 890 at P 435-442, 471.

processes consider generation and demand resources comparably with transmission projects.[47] In addition, one of the primary objectives of Order No. 1000 is to "ensure that transmission planning processes at the regional level consider and evaluate, on a non-discriminatory basis, possible transmission alternatives and produce a transmission plan that can meet transmission needs more efficiently and cost-effectively."[48] Among other things, the Commission required in Order No. 1000 that public utility transmission providers in a transmission planning region, in consultation with their stakeholders, create a regional transmission plan that will identify transmission facilities that more efficiently or cost-effectively meet the region's reliability, economic, and public policy requirements.[49] Commenters that suggest that lower-cost alternatives are not being considered are effectively challenging these Commission policies and the adequacy of the transmission planning processes that have been developed to comply with them.

In the experience of EEI's members, the Commission anticipated correctly in Order No. 679 where it rejected a request for a screening function for incentives in order to keep project implementation costs low and minimize cost overruns. The Commission found that "regional planning processes that evaluate and compare the costs and benefits of expansion proposals, as well as state commission reviews and requirement that costs be prudently incurred will serve to provide [this] screening function . . . and therefore additional processes are not necessary."[50] As a result of the Commission's transmission planning reforms, transmission projects are approved in regional planning processes that must take into account alternatives that can meet the region's

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[47] *See* Order No. 890-A at P 216.

[48] *See* Order No. 1000 at P 4 (2011).

[49] *Id*. at P 11.

[50] Order No. 679 at P 279.

needs on a more cost effective or efficient basis. At the same time, however, the regional planning processes must be able to address needs that require higher risk transmission solutions where no other alternative would suffice. In the experience of EEI's members, the Commission's incentive policies are fundamental to incenting the construction of such solutions.

D. Transparency in the Price of Incentives

The Joint Commenters argue that the Commission should make the price of incentives transparent. This issue has merit because, as a general matter, while the specific incentives awarded to a transmission project are transparent, the actual impact on consumer rates is not. EEI therefore agrees that anticipated customer rate impacts from requested incentives should be considered by the Commission when acting on a request for incentives. The benefit of using CWIP to reduce the overall project cost, as well as other ratemaking practices, can also be identified through such a review.

E. Basing Incentives Eligibility on Project Scale

The Joint Commenters argue that the Commission should not base eligibility for above-cost rewards on project scale. Again, EEI does not disagree with the point in principle, but there is no evidence that this is an issue that necessitates a change in course in the Commission's incentives policies. Generally, the cost to build any project depends on the risks presented and the risks may not correspond to scale. For example, despite their size, smaller transmission projects may still carry a higher risk due to siting constraints, and should be eligible for incentives under such circumstances. Existing Commission policy does not preclude consideration of incentives for smaller projects with high risks, and EEI has not observed that the Commission has granted incentives for a project only based on scale. No change in policy is necessary to address the Joint Commenters' concern.

F. ROE Incentives for Cost Overruns

Joint Commenters argue that the Commission should not apply ROE adders to cover construction cost increases over what was estimated for a project during the planning phase of the project. However, the Joint Commenters ignore important facts: often the routing and siting of a transmission line (as opposed to the description of the line on a one-line diagram) requires considerable re-evaluation, re-engineering, and final design during the routing and siting process. Together with the long lead times necessary to develop transmission, the frequent imposition of real world route-specific changes or rerouting for transmission projects to accommodate concerns of the public most directly affected by a project can result in costs that differ from initial estimates. EEI believes the Commission has correctly determined in the past that attempting to constrict incentives to initial project estimates would be unworkable and counter-productive to the purposes of Section 219 of the FPA.[51] The Commission has broad authority to review the prudence of a developer's expenses -- that is the appropriate vehicle to assess the reasonableness of any cost overruns. Incentives deemed appropriate for a project when approved should apply if the costs are prudently incurred.

G. Applying ROE Incentives to Abandoned Plant

Joint Commenters argue that the Commission should not apply ROE adders to abandoned plant amounts. By definition, abandoned plant cannot be recovered unless the project fails for reasons beyond the developer's control. For this reason, the Joint Commenters' suggestion that

[51] *See* Order No. 679 at P 121 n. 81 ("It would be difficult to hold electric transmission projects to the original budget estimate when it can be 10 to 15 years between the time the project is proposed and lines are actually built."); *New England Conference of Public Utilities v. Bangor Hydro-Electric Co., et al.*, 124 FERC ¶ 61,291 at P 47 (2008) (explaining that restricting incentives to the original budget "would send the wrong message to investors because it would create uncertainty about whether an approved incentive could be collected on costs that are unavoidable (but prudently incurred).").

abandoned plant does not provide an incentive to complete a project, but instead "promotes high-risk projects that never get built," is clearly based upon a flawed premise.[52] Because the cancellation has nothing to do with the developer's actions, there is no reason to penalize the developer for relying on an abandoned plant incentive in proceeding with the project. The Commission has explained that it requires a recipient of an abandoned plant incentive to make a Section 205 filing for recovery of abandoned plant costs in rates at the time the project is abandoned and to demonstrate therein that the costs were prudently incurred.[53] State public service commissions also perform prudence reviews prior to permitting a project to be recovered through retail rates. Because there is often a prudence review by state authorities and the Commission of abandoned plant costs before they can be included in rate base, there should be no real concern that the abandoned plant incentive creates a "lucrative business model" for developers to start projects, but not complete them.[54]

H. Categorizing Projects As Presumptively Ineligible for Incentives

Joint Commenters argue that the Commission should identify types of projects that are presumptively ineligible for incentives. EEI disagrees that the Commission should attempt to categorically exclude certain projects from incentives eligibility. The Commission's current policy that presumes incentives are appropriate for projects that enhance reliability or reduce delivered energy costs reflects Congress's intent in enacting Section 219 of the FPA. EEI believes this is the appropriate standard to continue. Attempting to categorize projects up-front would not be productive, as many projects cannot be narrowly defined; many projects meet both

[52] *See* Joint Commenters' Letter at 3.

[53] Order No. 679 at P 166; *Green Power Express LP*, 127 FERC ¶ 61,031 at P 52 (2009).

[54] *See* Joint Commenters' Letter at 3.

reliability and economic needs and the industry's "labels" for projects continue to evolve.[55] At the same time, a narrow definition of the types of eligible projects could frustrate Congressional intent without enhancing the ability of the Commission to appropriately encourage strategic transmission development.

IV. CONCLUSION

EEI appreciates this opportunity to submit reply comments on the issues raised in this proceeding. To continue progress made in encouraging necessary new transmission projects, EEI urges the Commission to consider adopting only those changes to the incentives policies of Order No. 679 suggested herein and in its initial comments in this proceeding. If the Commission has questions regarding these reply comments, please contact Tony Ingram, Senior Director, Federal Regulatory Affairs, (202) 508-5519, tingram@eei.org; or Chris Hargett, Manager, Federal Regulatory Affairs, (202) 508-5715, chargett@eei.org.

Respectfully submitted,

/s/ David K. Owens
David K. Owens, Executive Vice President
James P. Fama, Vice President, Energy Delivery
Edison Electric Institute
701 Pennsylvania Ave., NW
Washington, DC 20004

[55] *See, e.g., Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221 (2010), *order on reh'g*, 137 FERC ¶ 61,074 (2011) (accepting proposal for Multi-Value Projects, which may provide reliability and economic benefits as well as meet public policy goals).

ATTACHMENT C

REPLY COMMENTS OF NORFOLK SOUTHERN RAILWAY COMPANY

STB EX PARTE NO. 722

RAILROAD REVENUE ADEQUACY

WHITE PAPER

Industry Challenges

Fiscal pressures are being felt across all service offerings in the transportation industry, including Intermodal, Over the Road, Brokerage, and Dedicated.

Increased recruiting expenses and mileage pay, truck and maintenance costs, preparation for future regulations on equipment, lost productivity due to new regulations and a precarious market capacity situation are all stressing forces. The key factors highlighted below are:

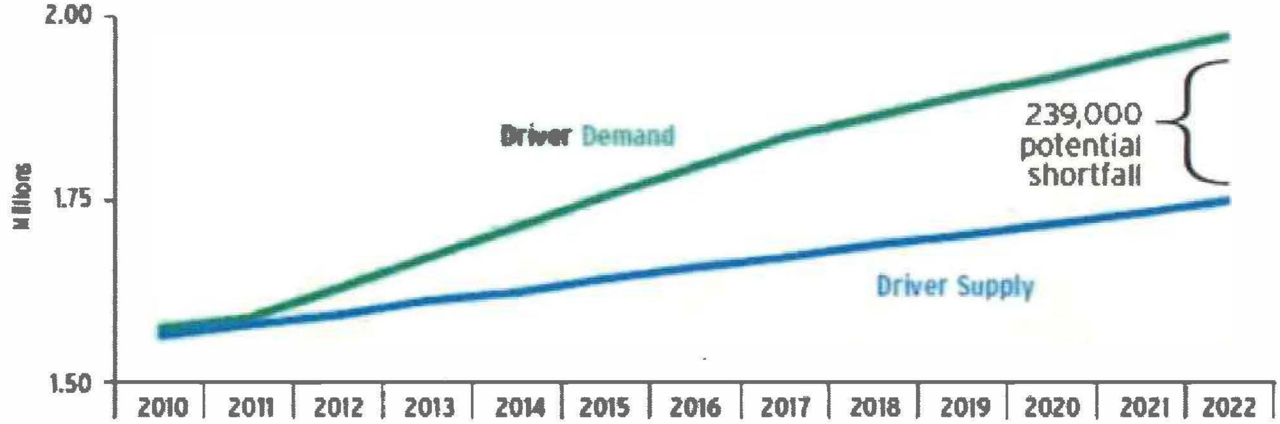
> Driver shortage and retention
> Tightening regulations/Hours of Service
> Capacity
> Railroad investment
> Equipment costs
> Productivity

Driver Shortage and Retention

Industry insiders and analysts alike have forewarned of a looming driver shortage since the last recession. According to the American Trucking Association (ATA), roughly 96,000 new drivers are required annually to keep pace with demand. If freight demand grows as expected, the annual driver shortage could balloon to nearly 240,000 by 2022.[1] There are many contributing factors, including an aging workforce, new and tightening regulations, and a need for increased capacity during our current economic upturn.

The accumulation of increasing difficulties is substantial enough to "begin moving the driver markets in the contract segment. Budgets for recruiting have risen, and driver pay is increasing."[2] Carriers have also reported increased recruiting expense, sign-on bonuses, and mileage pay[3] as they struggle to keep drivers in trucks.

Driver Shortage Worsening[1]



Source: ATA.com

Tightening Regulations/Hours of Service

Tightening regulations continue to contribute to fiscal pressure. Carriers continue to adjust to 3%-5% effective capacity reductions created by the latest changes to Hours-of-Service (HOS) regulations, which have been in effect since July 2013.[2] Downward pressure on capacity combined with freight volume growth could create an even tighter market for some trucking services[4], though the full impact of revised HOS rules isn't predicted to be absorbed until the use of Electronic Logging Devices (ELDs) becomes mandated. ELD regulations are predicted to go into effect by late 2015 or early 2016.[4]

Furthermore, several other proposed regulatory changes could further constrain trucking capacity over the next several years.[4] The Environmental Protection Agency (EPA) and the National Highway Traffic Safety Administration (NHTSA), for example, have released new standards that aim to reduce greenhouse gas emissions and fuel consumption for Class 8 trucks by approximately 29%. These changes are scheduled to be phased in between the 2014 and 2018 model years.[4]

According to BMO Capital Markets, "...The cost of the new trucks is expected to increase and maintenance costs may experience upward pressure due to the increased complexity of the engines (similar to the experience with the EPA-compliant engines introduced in 2010)."[4]

Productivity

Driver and asset productivity have fallen with the tightening influence of regulations, particularly Hours of Service. Carriers must regard both their equipment and their drivers' time as perishable commodities. In the days before HOS rules, scheduling inefficiencies could be compensated for by splitting driving time during the day. Through several successive revisions, HOS now mandates a continuously running duty clock. Once started, the duty clock expires exactly 14 hours later, with 11 hours of permissible driving time before a 10-hour break. Time spent at loading docks, fueling, and personal breaks invariably deducts from the 11-hour driving day. The latest round of changes in 2013 introduces limitations on the "34-hour restart," reducing the maximum hours a driver can work in a week by up to 12 hours, or 15%. According to the American Transportation Research Institute (ATRI), more than 80% of surveyed motor carriers have experienced a loss in productivity in relation to the changing HOS, and nearly half of these have stated more drivers are necessary to haul the same amount of freight.[5]

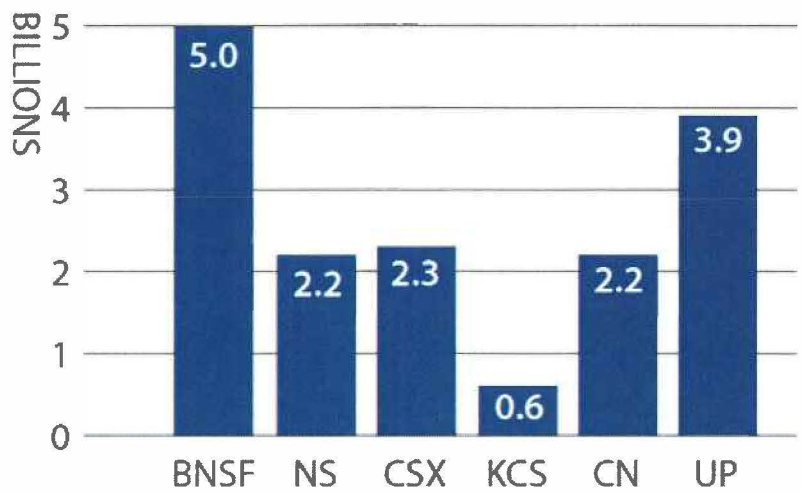
Like any high-investment, low-margin machine, tractors and trailers must be kept in continual productive motion in order to provide proper return. Carriers have segmented their freight and lanes into two broad groups of efficiency. One group, whose characteristics facilitate maximum utility of the 11-hour day and generates productive payload miles, earns the most favorable pricing and anchors sustainable freight networks. The other, with disproportionate consumption of time in unpaid empty miles and in non-driving time awaiting pickup or delivery appointments outside of reasonable transit time, must be priced accordingly.

Rail Investment

Service recovery has remained stalled as railroads continue to cope with substantially higher volumes in both intermodal (+7.9% YOY) and carload (+5.6% YOY). Grain movements saw a whopping 21.5% increase, but nearly all sectors are seeing growth as the economy recovers.[6] All of these commodities use the same tracks, locomotives, crews, and other resources to move freight through their networks. Intermodal shippers should certainly pay attention to capacity consuming activities such as crude-by-rail and re-regulation.

For the most part, the service issue is not due to lack of fixed capacity, such as track and terminals, since railroads continued to invest heavily in their networks during the recession years[7] and their investment activity continues at record levels. Rather, the railroads need more locomotives and crews. Unfortunately, recruiting, hiring, and training a crew member takes time. Furthermore, locomotives are going to become harder to come by. According to *The Wall Street Journal*, with the new Tier 4 air quality regulations coming into effect on January 1st, 2015, locomotive manufacturer EMD "doesn't anticipate having production units ready until 2017."[8] This means only one U.S. locomotive manufacturer (GE) after December 31st.

Class I Railroads Planned Spend[9]



Source: Progressive Railroading

Trailer-on-flatcar (TOFC) remains the strongest intermodal segment at +11.7% year over year, potentially reflecting a shift by shippers and motor carriers away from the highway due to container supply constraints and capacity restrictions in trucking.[10] In fact, in an analysis of the first 34 weeks of 2014, U.S. railroads reported cumulative volume of 8,730,830 intermodal units, up 5.7 percent from last year.[11]

The relatively tight nature of the truckload market and the consequent strength in truck rates could provide upward momentum on intermodal pricing through the 2015 bid season.[10]

Insight from initial reports suggests capital expenditures could likely increase for Class I railroads an average of 9 percent overall in 2014. According to Progressive Railroading, "Railroads once again will top 18 percent of annual revenues on capex, compared with 3 percent for the 'average industrial' company." Further increases could also be announced during the year, as they were in 2013.[9]

Capacity

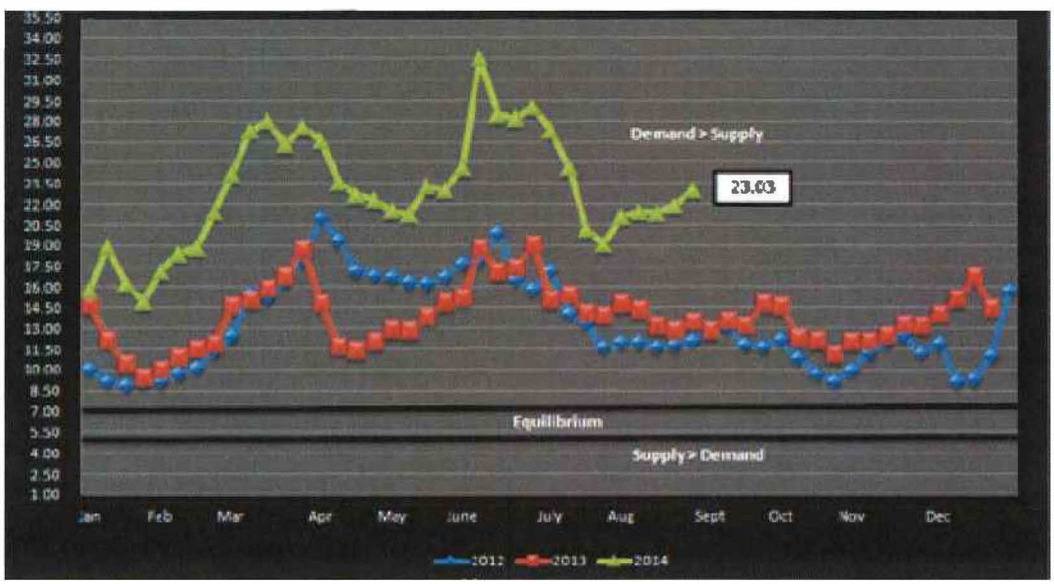
The market will stay near tipping point because of the strength of demand. At best, seasonal peaks and any event which swells demand or degrades capacity will cause a series of short capacity crises. Another wave of regulations will likely hit in 2016, potentially creating capacity concerns, thus making cooperative carrier relationships highly necessary.[3]

Furthermore, recent field reports suggest increasing labor and purchased transport costs. Contract rates are also beginning to move upwards.[3] As seen in the FTR Transportation Intelligence Forecast, total shipping costs are projected to rise in 2014 and in 2015.[3]

In truckload, contract segment costs have begun to rise as labor stress in spot markets leaks into the contract space. Reports for the second quarter show mixed results in cost control concerning Less-Than-Truckload, though most fleets are increasing hiring expenses. Rail is operating at high capacity and total rail costs are projected to rise in 2015.[3]

Truckload cannot meet current demand as changing regulations, the driver shortage, and underinvestment make capacity expansion unlikely.[12] Projections for the full year show a slight softening and there may be greater capacity available for truckload in the second half of the year.[13] However, current capacity trends are holding at 98%, just below the point of serious shortages.[3] FTR Transportation Intelligence predicts the fragile balance to "continue until regulatory pressures increase again in later 2016."[3]

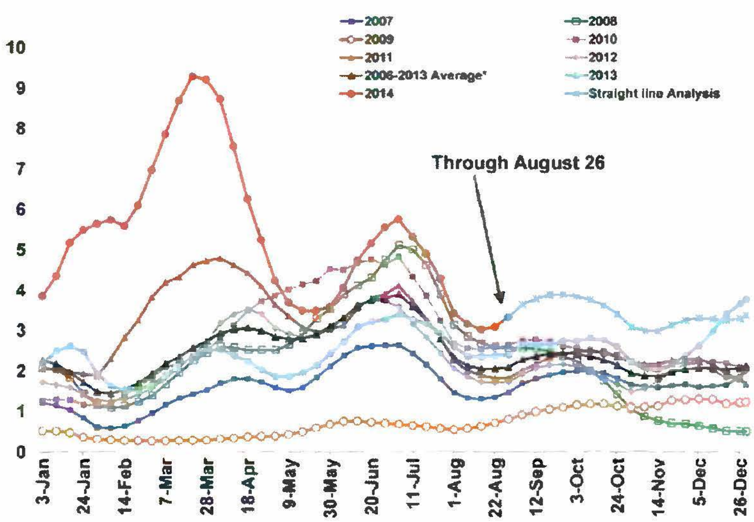
Weekly MDI Data[14]



Weekly MDI Data[15]

INDUSTRY TRENDS	MONTH June 2014 vs May 2014	YEAR June 2014 vs June 2013
Spot Market Loads	+11%	+54%
Spot Market Capacity	-20%	-2.8%
Van Load-To-Truck	+51%	+43%
Van Rates (Spot)	+5.1%	+12%
Flatbed Load-To-Truck	+30%	+134%
Flatbed Rates (Spot)	+3.4%	+11%
Reefer Load-To-Truck	+42%	+34%
Reefer Rates (Spot)	+4.7%	+8.0%
Fuel Prices	-0.9%	+1.6%

Dry Van Truckload Freight Index[16]



The index measures the incremental demand for Dry-Van Truckload services compared to the incremental supply. When a given reading is above prior years' level, it means there is more freight demand relative to available capacity. When a given reading is below prior years' level, it means there is less freight demand relative to capacity. *2006-2013 average trend line excludes financial crisis years of 2008 and 2009; Source: Morgan Stanley Research, Data as of 8/26/2014


Rising Equipment Costs

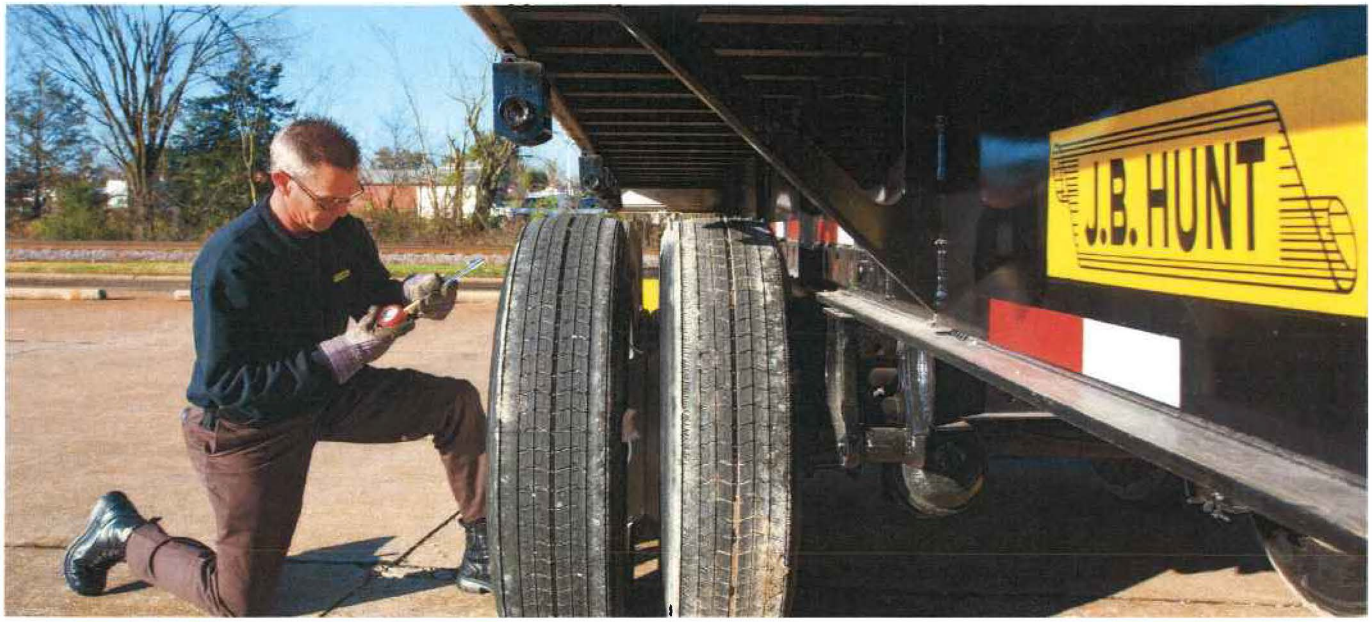
Increased demand means carriers must maintain and grow reliable and efficient fleets. Largely due to increasingly stringent emission standards, the cost of new Class 8 tractors continues to rise.[4] EPA mandates, inflation, and manufacturer cost increases contribute to base price increases. ACT Research estimates the cost of a new tractor has increased by roughly 25% over the 2006-2012 period.[4] Furthermore, following each EPA mandate, Class 8 tractors have experienced an average 10% rise in repairs and breakdowns.[17] With new emission and MPG mandates slated for 2014-2017, carriers are preparing for additional capital expenditures and mechanical challenges for the next generation tractors.

Conclusion

The transportation industry faces many challenges in 2015 and beyond. As highlighted above, increasing recruiting expenses and mileage pay, truck and maintenance costs, preparation for future regulations on equipment, lost productivity due to new regulations and a precarious market capacity situation are all stressing forces.

Shippers should prepare for significant cost recovery and network rationalization efforts from providers of both highway and intermodal services beginning in late 2014 and into 2015.

We hope this document has been informational to you and helpful as your organization begins considering the 2015 budgeting process.



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About J.B. Hunt

J.B. Hunt Transport, Inc. focuses on providing safe and reliable transportation services to a diverse group of customers throughout the continental United States, Canada and Mexico. Utilizing an integrated, multimodal approach, we provide capacity-oriented solutions centered on delivering customer value and industry-leading service.

Our stock is traded on NASDAQ under the ticker symbol JBHT and is a component of the Dow Jones Transportation Average. **For more information about our Company, visit www.jbhunt.com.**

ATTACHMENT D

REPLY COMMENTS OF NORFOLK SOUTHERN RAILWAY COMPANY

STB EX PARTE NO. 722

RAILROAD REVENUE ADEQUACY

VERIFIED STATEMENT NO. 1

BEFORE THE

INTERSTATE COMMERCE COMMISSION

EX PARTE NO. 393 (SUB-NO. 1)

STANDARDS FOR RAILROAD REVENUE ADEQUACY

VERIFIED STATEMENT

OF

WILLIAM J. BAUMOL

and

ROBERT D. WILLIG

August 4, 1986

*   *   *   *

APPENDIX A

February 25, 1985

Economists' Statement in Support of
the Staggers Act

We, the undersigned economists, understand that in the ninety-ninth Congress, amendments are likely to be proposed that would substantially alter major provisions of the Staggers Rail Act of 1980, with the general effect of reducing the freedom of individual railroads to set their rates in accordance with market forces and lessening railroads' opportunity to earn an adequate return on capital. Without commenting on the details of the Act or on the specifics of the Interstate Commerce Commission's implementation of it, we do express our judgement that, in its main thrust, the Staggers Act has brought about a regulatory regime much more attuned to the state of competition that now exists among the various modes of transportation.

The Staggers Rail Act of 1980 was part of a broad, long-term effort to eliminate inefficient economic regulation. That movement, with its enhanced reliance on market forces, has affected such diverse sectors of the economy as transportation, telecommunications and finance. It has its intellectual roots in economic analysis of recent decades which showed that economic regulation has often failed to serve the interest of the public at large; that effective competition serves as a better stimulant to economic efficiency than governmental intervention in the details of market activity and that many industries, including rail transportation, have faced greatly increased competition during the period since World War II.

Partly because of the failures of economic regulation, the railroads, during the years prior to the Staggers Act, deteriorated to a point where their ability efficiently to serve the transportation demands of the country had been severely impaired. Congress was unwilling to see further deterioration of the railroads so long as there was substantial demand for their services. Congress also rejected both railroad nationalization and major new direct rail subsidies, at taxpayers expense. Instead, it elected to provide the railroads greater opportunity to become self-sustaining, by increasing their freedom to price their services as warranted by conditions in the competitive markets they serve. At the same time, the Act provided for the identification of markets in which the railroads held excessive market power and provided for continuing regulation of prices in those markets.

In light of the fact that the Staggers Act stopped short of complete economic deregulation, a number of issues were raised and addressed in the Act and in its implementation, such as:

1. the level of revenues that railroads must be permitted to earn in order to build and maintain the capability to serve their markets.

2. the criteria on which to base a finding that competition is inadequate, i.e. that "market dominance" is present;

3. the criteria for setting rates, given market dominance.

We subscribe to the following principles in addressing these issues:

1. The appropriate standard for determining the adequacy of railroad revenues is a rate of return equal to the current cost of capital on the replacement value of all rail assets that are required to meet the demands for railroad service, regardless of the source of funds used in investing in those assets.

2. In determining whether a railroad faces adequate competition in a particular market, it is appropriate for the Interstate Commerce Commission to consider all sources of competition in that market, including: competition from other carriers moving a given product between the given points of origin and destination, competition arising from consignees' ability to obtain the same product from other sources and to obtain close substitute products from any source, and shippers' ability to sell in other markets.

3. In setting "reasonable rates", which we take to mean rates that encourage the efficient use of resources not only of the railroads and their customers but also of the entire economy, the following principles should apply:

- o Where marginal cost pricing produces total revenues that are less than total cost, some form of pricing that reflects the responsiveness of demand to price (Ramsey-like pricing) is economically efficent and, where returns are below the market cost of capital, is essential for railroad financial viability;

- o Rate prescriptions based on fully allocated cost or other ratios of rate to cost are, in such circumstances, arbitrary and inefficient;

o Defined as the cost a rail carrier would currently have to incur to furnish a particular service or group of services in isolation, "stand-alone" costs provide, in principle, an objective standard for setting the maximum price a railroad, whose revenues are inadequate, should be permitted to charge in markets where competition is not effective.

In summary, we believe that the Staggers Rail Act of 1980 to have been a substantial step toward rationalizing transportation policy and that continued pursuit of the principles stated above would serve the interests of the public at large.

____
(Signature, title, current affilliation for identification only)

______________________________ ________________
(Prior positions) (date)

ECONOMISTS ENDORSING the ECPP STATEMENT in SUPPORT OF THE STAGGERS ACT

Members of the ECPP

Kenneth J. Arrow,
Nobel Laureate; Joan Kenney Professsor of Economics, Stanford University
Former: President American Economic Asociation

William J. Baumol,
Professor of Economics, Princeton University
Former: President, American Economic Association; Senior Author: Contestable Markets and the Theory of Industrial Structure

Allen R. Ferguson,
Economist, President A.F.E., Inc.
Former: President, Public Interest Economics Foundation; Coordinator for International Aviation, U.S. Dept. of State

Hendrik S.Houthakker,
Professor of Economics, Harvard University
Former: Member, Council of Economic Advisors

Norman H. Jones Jr.,
Economist, President N.H. Jones, Inc.
Former: Dep. Asst. Sec. Commerce

Isabel V. Sawhill,
Senior Fellow, The Urban Institute
Editor: The Reagan Record and The Reagan Experiment

Lester Thurow,
Professor of Economics, Sloan School of Management, MIT
Author: Zero Sum Society

James Tobin,
Nobel Laureate, Sterling Profesor of Economics, Yale University
Former: President, American Economic Association

Other Economists

Gardner Ackley,
Professor Emeritus of Economics, University of Michigan
Former: Chairman, Council of Economic Advisors; U.S. Ambassador to Italy

Bruce Allen,
Professor of Economics, Michigan State University

Arman A. Alchian,
Professor of Economics, UCLA

Elizabeth Bailey,
Dean, Business School, Carnegie-Mellon University
Former: Vice Chair, Civil Aeronautics Bd.; Head Ec. Res. Dept. Bell Lab.

Francis Bator,
Professor of Political Economy, Harvard University
Former: Deputy Special Assistant to the President for National Security Affairs

George Break,
Professor of Economics, University of California, Berkeley

Harrison S. Campbell,
Associate Professor, University of Lowell
Former: Vice President, Charles River Associates; Vice President, New York City Rand Institute

William M. Capron,
Chairman and Professor, Dept. of Econ., Boston University
Former: Asst. Dir. Bur. of Budget

Richard E. Caves,
Professor of Economics, Harvard University

James A. Constantin,
David Ross Boyd Professor of Business Administration, University of Oklahoma

J. Dewey Daane,
Frank K. Houston Professor of Banking, Owen Graduate School of Management, Vanderbuilt University
Former: Member, Bd. of Govs. Fed. Res.

Harold Demsetz,
Professor of Economics, UCLA

George C. Eads,
Dean, School of Public Affairs, University of Maryland
Former: Member, Council of Economic Advisors; Research Program Director, the Rand Corp.

Robert Eisner,
William R. Vienan Professor of Economics, Northwestern University

Jose A. Gomez-Ibanez,
Professor, Kennedy School of Government, Harvard University

Gottfried Haberler,
Resident Scholar, American Enterprise Institute
Former: Professor of Economics, Harvard University

Robert H. Haveman,
John Bascom Professor of Economics, University of Wisconsin
Former: Sr. Ecst., Jt. Econ. Comm. U.S. Congress

Arnold C. Harberger,
Professor of Economics, University of Chicago and UCLA

Robert W. Harbeson, McKinley Professor of Public Utility Economics, Emeritus, University of Illinois
Former: Principal Economist, Bureau of Economics, ICC

Stanley J. Hille,
College of Business and Public Administration, University of Missouri

George W. Hilton,
Professor of Economics, UCLA

Jack Hirshleifer,
Professor of Economics, UCLA

Charles C. Holt,
Professor of Management, University of Texas at Austin

Richard H. Holton,
Professor of Business Administration, University of California, Berkeley
Former: Asst. Sec. of Commerce

Leland L. Johnson,
Senior Economist, The Rand Corporation
Former: Assoc. Administrator Nat'l Telecommunication & Information Admin.

Theodore E. Keeler,
Professor of Economics, University of California
Former: Sr. Fellow, Brookings Institution

Michael H. Lee,
Economist, Montana Public Service Commission

Paul W. McCracken,
Edmund Ezra Day Distinguished Professor of Business Administration, the University of Michigan
Former: Chairman, Council of Economic Advisors

William H. Meckling,
Dean Emeritus, Graduate School of Management, University of Rochester

Alan H. Meltzer,
John M. Olin Professor of Political Economy and Public Policy, Carnegie-Mellon University

Leon Moses,
Professor of Economics, Northwestern University

Willard F. Mueller,
Professor of Economics, University of Wisconsin
Former: Exec. Dir., Comm. on Price Stability, Exec. Off. of the Pres.; Chief Economist, F.T.C.

James C.Nelson
Professor of Economics Emeritus, Washington State University

Richard R. Nelson,
Professor of Economics, Yale University

Edmund A. Nightingale
Professor of Economics and Transportation Emeritus, University of Minnnesota

Wallace E. Oates,
Professor of Economics, University of Maryland

Walter Y. Oi
Elmer R. Milliman Professor of Economics, University of Rochester

Josephine E. Olson
Professor, Graduate School of Business, University of Pittsburgh

Theodore Otis
Economist, Utilities Division, Montana Dept. of Public Service Regulation

Marc J. Roberts,
Professor of Political Economy and Health Policy, Harvard School of Public Health

Thomas Romer,
Professor of Economics and Politial Economy, Carnegie-Mellon University

Thomas C. Schelling,
Professor of Economics, Harvard University

Richard L. Schmalensee,
Professor of Applied Economics, Sloan School of Management, MIT

Richard Sullivan,
Professor of Economics, Carnegie-Mellon University

Robert Willig,
Professor of Economics and Public Affairs, Princeton University
Former: Supervisor of Economic Research Dept., Bell Labs.

Lee Wilson,
Professor of Economics, University of Wisconsin

Anthony M. Yezer,
Associate Professor of Economics, George Washington University

Richard Zeckhauser,
Professor of Political Economy, Harvard University

ATTACHMENT E

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Transmission Investment

Adequate Returns and Regulatory Certainty Are Key

June 2013

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Transmission Investment

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Phone: 202-508-5000
Web site: www.eei.org

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I. Executive Summary

A Robust Transmission System Is Critical to Electric Reliability

The North American electric system is comprised of a complex, interconnected network of generating plants, transmission lines, and distribution facilities. Electric utilities have interconnected their transmission systems to ensure reliability of service and to facilitate energy exchanges and other market transactions. Transmission lines link the generators of electricity to the distributors, transporting electricity to local electric utilities, which in turn deliver it to customers.

The numerous benefits of a robust transmission network are undisputed, and the nation's shareholder-owned electric utilities have a long history of making cost-effective investments in needed and beneficial transmission infrastructure. In fact, these utilities have increased their investment in transmission significantly in recent years, and are projected to spend an additional $54.6 billion on transmission infrastructure through 2015 (real $2011). At the same time, electric utilities have invested in cleaner energy sources, greater efficiency, and more resilient and flexible distribution facilities that use modern, smart technologies.

The Federal Energy Regulatory Commission (FERC or the Commission), Congress, and the Administration have determined that cost-effective, properly planned electric transmission investments are needed, and they all have taken actions in the past decade to promote investment. These investments ensure a reliable and efficient electric power grid that can promote robust competitive wholesale electric markets; reduce congestion; support delivery of renewable and cleaner energy resources; respond to emerging security threats; and safely and securely meet the needs of a 21st-century digital economy that increasingly relies on electricity.

Transmission Investment Requires Significant Capital

The electric power industry is the most capital-intensive industry in the United States, with transmission assets accounting for just one aspect of overall utility investments. In 2012, electric utilities invested $90.5 billion in generation, transmission, and distribution systems.

Compared to other assets, transmission investments are extremely risky and require long lead times for the planning process and stakeholder involvement. They also often face extensive and sometimes successful litigation on siting and related issues; in addition, cost recovery can be challenging. As a result, investors require predictable, sustainable, and reasonable returns, or they will reallocate their capital into one of the many other sectors that offer a more competitive return and less risky investments. There are many attractive investment options at this time.

The nation is in a unique economic situation, as the Federal Reserve and other government policies have reduced the cost of debt to serve important economic goals. While there often has been a consistent spread between the costs of debt and equity in the past, the electric power industry, like other domestic businesses, has seen that spread widen considerably in recent years so that the cost of equity is far higher than the traditional spread compared to the cost of debt.

Key Regulatory Policy Goals Must Be Sustained

In recent years, FERC has relied upon a discounted cash flow (DCF) financial model to determine utility cost of equity for transmission. However, that model has not been adjusted to reflect the fundamental shift between the cost of debt and equity that has occurred during the current slow economic recovery. As a result, application of the traditional DCF model can result in dramatically lower returns on equity (ROEs) for transmission investment. Such an application fails to recognize that:

- The current returns are still within the range of reasonableness;
- There is no link between record low interest rates and investors' expected return on transmission investment;
- Adequate long-term returns are important to the long-term investment in the transmission system and other policy goals.

It also does not demonstrate there is any reduction in the risks of planning, siting, and building transmission. While transmission accounts for about 11 percent of an electric customer's total bill, ROEs need to be predictable and sustainable over the long-term in order for a robust, modernized transmission system to produce savings and to promote many different policy benefits.

The Edison Electric Institute (EEI) supports a reasonable and practical solution to a strict application of these challenges. In the past, FERC, like all regulatory commissions, has adjusted its regulatory methodologies to reflect changes in economic and financial realities to ensure that ROEs remain within the range of reasonableness. It is critical that FERC stay the course and provide regulatory certainty and adequate returns by making a few simple adjustments to its analysis of the current challenges and to the DCF methodology. Otherwise, the nation's electric utilities and their investors could divert needed capital to investments with greater returns, jeopardizing transmission reliability.

II. Introduction

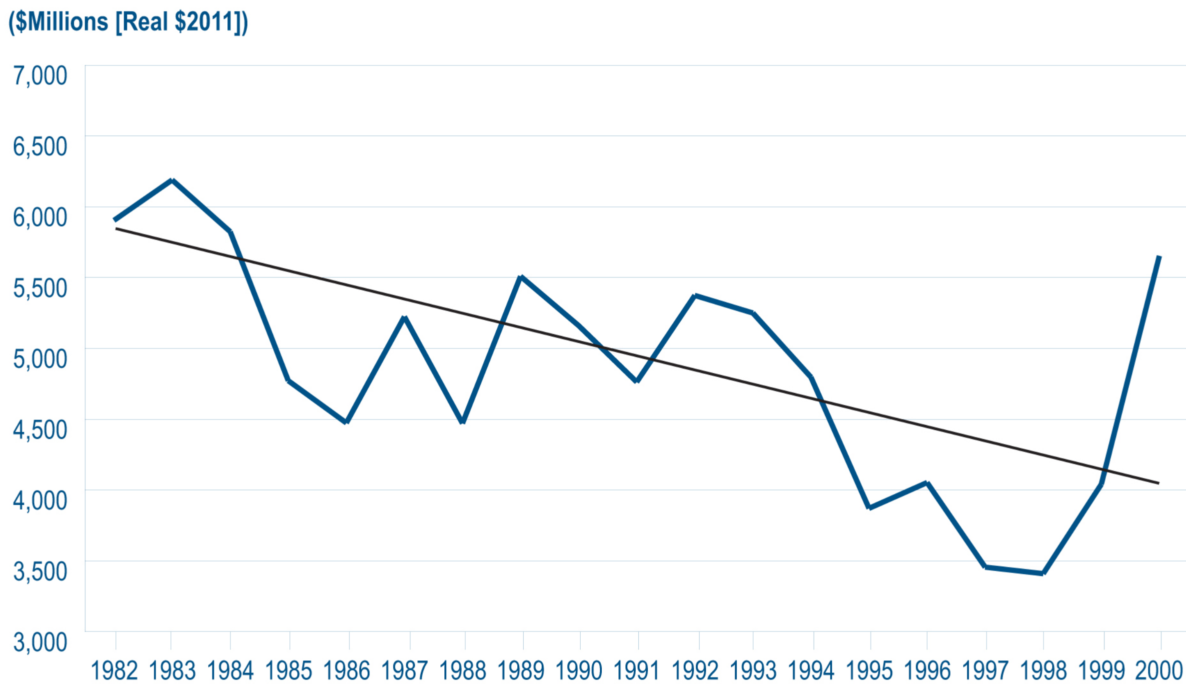
EEI's shareholder-owned electric utility members[1] are making cost-effective transmission investments to ensure that the power grid is reliable and efficient, meets 21st-century electricity needs, and supports competitive wholesale markets. There are numerous benefits of a robust transmission system, which have been recognized by Congress,[2] the Administration,[3] and FERC.[4] Recently, however, several parties have advocated for significant reductions to existing FERC-authorized returns on transmission investments. The parties raising questions rely on a narrow, mechanistic application of FERC's preferred DCF financial model for determining authorized returns during the current period of artificially low record interest rates. This kind of application can produce ROE results that are downward-biased and are insufficient to meet legal and regulatory standards;[5] moreover, such results would compromise established policy goals. These parties fail to: demonstrate that the link between the record low interest rates and investors' expected returns on transmission investment has remained constant; recognize the widespread benefits of a robust transmission network; demonstrate that the risks of developing transmission have diminished; and recognize the premise upon which historical transmission investments were made, *i.e.*, stable returns over the asset lives of the facilities.

EEI urges FERC to consider all of the benefits of transmission, as well as its importance to the Commission's policy goals and regulatory standards, in addressing these challenges by recognizing the limitations of the DCF analysis and assessing the application of the DCF methodology described herein. Over the long term, failure to retain stable and adequate returns for transmission investment that reflect the actual financial conditions influencing that investment likely will prevent the industry from attracting the necessary capital required for a 21st-century transmission grid. Ultimately, this may lead to less efficient and less cost-effective energy solutions for electricity consumers.

III. Robust Transmission Infrastructure Provides Numerous Benefits to Customers

Over the past decade, EEI members have reversed the trend of declining investment in our nation's transmission infrastructure that occurred prior to 2000, as shown in the graph below.

Historical Transmission Investment by Shareholder-Owned Electric Utilities (1982-2000)



Source: SNL Financial and EEI Finance Department

Since 2001, EEI members' year-over-year transmission investment has nearly doubled from $5.8 billion in 2001 to $11.1 billion in 2011 (real $2011).[6] These transmission investments have funded necessary projects, including several projects supported by FERC's Order No. 679,[7] which implemented Congress' directive to incentivize improvement and expansion of our nation's transmission infrastructure.

Customers receive considerable benefits from these transmission investments including:

- An assurance of U.S. electric system reliability;
- Facilitation of robust electric market competition;
- Reduced congestion and line loss costs;
- Integration of new generation resources, including renewables;[8]
- The necessary upkeep of infrastructure; and

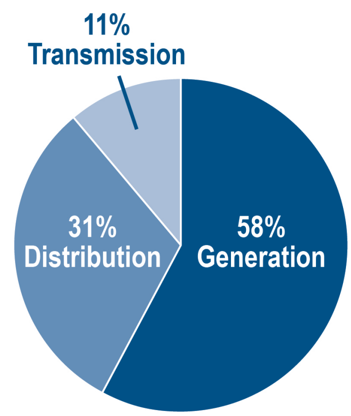
- A more resilient grid in the face of extreme weather events.

All of these benefits are provided by transmission plant, which remains the smallest portion of an electric customer's bill. On average, transmission costs are approximately 11 percent of the price of electricity when compared to generation and distribution.[9]

The benefits of robust transmission infrastructure can be seen around the country:

- Investments made by transmission owners in ISO-New England have resulted in annual savings of approximately $700 million in reduced energy and capacity market costs for electric customers.[10]
- In PJM, the Trans-Allegheny Interstate Line (TrAIL) project that entered service in 2010 resulted in a reduction of congestion costs of 50 percent, saving customers millions of dollars during 2010 and 2011.[11]
- In the MISO region, the Multi-Value Projects (MVPs) portfolio alone is expected to create thousands of jobs and provide additional energy-cost savings. Specifically, MISO estimates that the 2011 portfolio of 11 transmission projects will provide benefits between $15.6 and $49.3 billion, approximately 1.8 to 3.0 times the projected capital costs of $5.2 billion (real $2011).[12]

Major Components of U.S. Average Electricity Price, 2011



Investing in transmission infrastructure also provides grid resiliency, which helps to avoid major electricity blackouts that can result in significant economic losses. For example, due to a transmission issue starting on August 14, 2003, an estimated 50 million people in the Midwest and Northeast United States and Ontario, Canada, experienced an area-wide blackout lasting up to four days in some areas. Total estimates of business and other losses for this event ranged from $4 billion to $10 billion for the outage periods.[13]

The Need for a Robust Transmission Grid Is Undisputed

EEI believes the clear conclusion of governmental and regulatory bodies is that the public policy benefits of transmission investment are without dispute, and the need for greater transmission investments is clear.

FERC continues to articulate public policy reasons for additional investment in transmission infrastructure and recognizes the benefits of a robust transmission system. For example, with the issuance of Order No. 1000, the Commission stated that "[t]he need for additional transmission facilities is being driven, in large part, by changes in generation mix."[14] Also, FERC stated that "additional, and potentially significant, investment in new transmission facilities will be required in the future to meet reliability needs and integrate new sources of generation;" and "…increased adoption of [renewable portfolio standard measures] has contributed to rapid growth of renewable energy resources that are frequently remote from load centers, and thus [increase the] need for transmission to access remote resources …."[15] This also is consistent with FERC's strategic goals (Fiscal Years 2009-2014), which state, in part, that the Commission will "[p]romote the development of safe, reliable and efficient energy infrastructure that serves the public interest" in order to fulfill its mission to "[a]ssist consumers in obtaining reliable, efficient and sustainable energy services at a reasonable cost through appropriate regulatory and market means."[16] To support this strategic goal, FERC has pursued policies to support electric transmission planning and to encourage new electric transmission facilities that advance efficient transmission system operation.[17]

In January 2011, the five sitting FERC Commissioners endorsed the need for transmission investment in a letter to the editor of *The Wall Street Journal*, disputing an editorial critical of FERC's proposed rule covering transmission planning and cost allocation. The Commissioners stated "investment in transmission promotes efficient and competitive electricity markets, which hold down prices for consumers. Transmission investment also enhances reliability and allows access to new energy resources."[18] Indeed, additional transmission investment is needed as electricity providers continue to address the evolving energy needs of our nation.

Recent extreme weather events also have highlighted the need for reinforcing and upgrading electric infrastructure.[19] In addition, the U.S. Environmental Protection Agency (EPA) is promulgating and implementing evolving regulations that are driving significant generation retirements. Managing these generation retirements will increase the need for new and upgraded transmission assets. For example, PJM recently approved more than $5 billion of transmission enhancements driven by plant retirements, generation projects switching to natural gas, and the growth of wind power projects.[20]

Moreover, transmission development to integrate and support renewable energy resources remains critical, especially those remotely located resources that need access to the market and load centers. For example, the American Wind Energy Association recently released a report highlighting that "transmission is 'extremely important' to the future of the wind industry in the United States, and as noted previously, is the 'industry's number one barrier' to integrating more wind energy."[21]

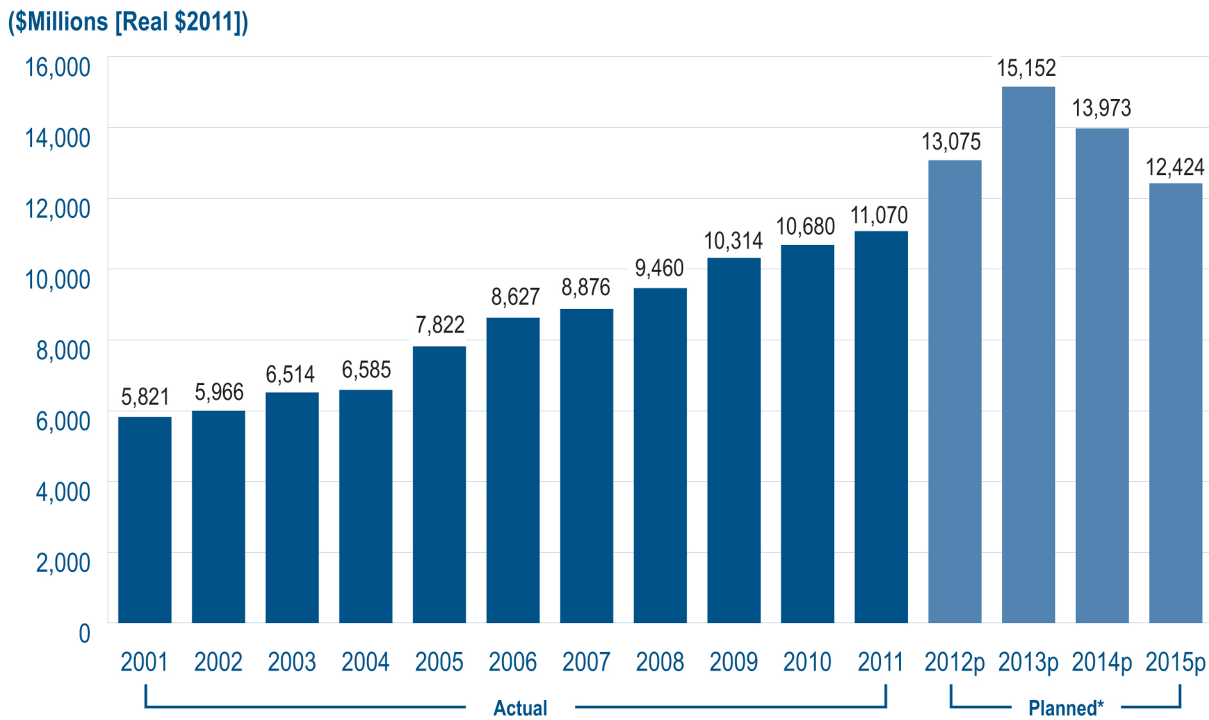
Meanwhile, the North American Electric Reliability Corporation (NERC) and FERC continue to develop and approve a growing list of mandatory standards aimed at ensuring Bulk Power System reliability, requiring incremental capital investments for all utilities that own transmission.[22] In addition, the cyber and physical security needs of the nation's critical infrastructure, including the electric grid, also require increased attention and investment.[23] While there have been increases in distributed energy resources, transmission investments still are needed to support these resources locally and in the wholesale energy markets. And, although demand response and energy efficiency may reduce electricity usage, increased customer participation does not affect the need for transmission materially. Generation resources still are needed to meet electricity demand, and transmission is needed to integrate these resources and reduce system congestion.

As the Nation's Demand for Reliable, Affordable Electricity Grows, EEI Members Remain Committed to Developing the Transmission Needed to Provide Reliable Electricity

EEI members have responded to the growing transmission needs of our nation. The graph below demonstrates EEI members' commitment to meet those needs as demonstrated by the recent increase in transmission investments. These investments have been encouraged by FERC's subsequent policies implementing the Energy Policy Act of 2005 (EPAct 2005).

In response to the sustained need for transmission investments, EEI projects that its members will invest an additional $54.6 billion in transmission through 2015 (real $2011).[24] However, planned transmission investments are affected by economic conditions, capital allocation, financial markets, and public policy objectives. Currently, EEI forecasts a decrease in transmission investment after 2013 (relative to 2013), in part because several major projects recently have been modified, delayed, or cancelled. While transmission investments by EEI members during 2014 and 2015 are anticipated to be significantly higher than in 2011, it is important to note that, given the length of time it takes to plan, permit, and build significant transmission projects (up to 10 years), the ramp up in investment reflects investment decisions made in response to policies enacted by Congress in EPACT 2005 and appropriate ROEs. These planned transmission investments are premised on ROEs that are consistent with currently authorized levels.

Actual and Planned Transmission Investment by Shareholder-Owned Electric Utilities (2001-2015)



p = preliminary
Note: The Handy-Whitman Index of Public Utility Construction Costs used to adjust actual investment for inflation from year to year. Forecasted investment data are adjusted for inflation using the GDP Deflator.
*Planned total industry expenditures are preliminary and estimated from 85% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey and from the FERC Form 1 reports.
Source: Edison Electric Institute, Business Information Group

Longer-term, EEI's 2013 *Transmission Projects: At A Glance* report highlights more than 150 planned transmission projects, totaling approximately $51.1 billion (nominal $) planned through 2023. These projects do not include investments in transmission upgrades or replacements to existing facilities.[25] Fifty-two percent of these projects are interstate projects, which face significant challenges for siting, permitting, cost allocation, and cost recovery from numerous federal, state, and local entities. Seventy-six percent of these projects support the integration of renewable resources, such as wind and solar.[26] These projects are critical to assisting electricity providers' cost-effective compliance with renewable portfolio standards (RPS) currently in place in 29 states and the District of Columbia.[27] For example, Southern California Edison's Tehachapi Renewable Transmission Project is expected to accommodate 4,500 megawatts (MW) of high-quality renewable resources, meeting approximately one-third of California's 33-percent RPS.[28]

While the proposed investment numbers are significant, The Brattle Group estimates that the *need* for additional transmission investment through 2030 is in the range of $240 billion to $320 billion.[29] With supportive FERC policies in place since EPAct 2005, the industry has been able to devote more capital expenditures to transmission and is moving forward to build transmission. But, much more needs to be done, and the risks and challenges of developing and building transmission have not lessened. Many projects that proposed—and needed to provide—the most significant benefits to customers, are the large regional and inter-regional, backbone projects; these projects also carry the most upfront development time, longer construction schedules, and overall risk.

As previously noted, EEI members are obligated to maintain the reliability of the electric system.[30] While EEI members take such obligations seriously, it will be increasingly challenging to ensure robust reliability if expected returns fall below those for other investments that are more attractive and less risky than transmission. Moreover, the choices of how to meet particular reliability needs are numerous, and electric utilities must make those choices within the confines of capital limitations. If ROEs for transmission are not sufficient, a utility may choose a short-term, more-local project or an alternative resource solution to maintain reliability rather than choose the riskier, more strategic option that could provide additional benefits to customers and be more cost-effective. Given the numerous risks and challenges associated with developing large-scale transmission, it is critical that returns are sufficient to encourage EEI members to focus on evaluating and building the larger, more challenging projects needed for a more robust electric grid that will provide reliability and other benefits to customers in both the short and long term.[31]

Order No. 1000 Effectiveness Relies on Continued Transmission Investments

As previously noted, in Order No. 1000, FERC recognized the benefits of a robust transmission system and the need for additional investment. Order No. 1000 establishes key regional planning and cost-allocation requirements for transmission projects. The goal of Order No. 1000 is to promote more coordinated regional planning and inter-regional planning processes to identify needed, cost-effective, transmission along with the implementation of regional cost allocation for projects that provide regional benefits.[32]

These checks and balances protect customers by ensuring that only needed, cost-effective, and efficient transmission projects that meet local and regional needs ultimately are constructed. Properly structured, these open, transparent and comprehensive processes should identify cost-saving opportunities, support robust wholesale electricity markets, and facilitate the construction of new transmission to meet reliability and public policy requirements. However, without adequate returns to support investment in needed transmission, projects evaluated in these planning processes may not be undertaken because limited capital will be invested elsewhere, likely resulting in delay or absence of projects required to address congestion, to implement public policy objectives, and to bring benefits to customers.

IV. The Risks and Challenges of Developing Transmission Have Not Diminished

Investing in transmission introduces a number of risks and challenges, including significant development risk around ultimately championing a project through the planning process,[33] financing risks, and permitting risks and challenges. Congress recognized the importance of transmission investment and the attendant risks of development when it enacted, as part of EPAct 2005, section 219 of the Federal Power Act (FPA). Congress has not amended or taken other action to diminish the importance of transmission investment since EPAct 2005, nor have project risks and challenges fundamentally changed.

Given these risks, transmission investments are unlike investments in any other utility infrastructure where the projects tend to be smaller in size, shorter in duration, and are located in one area. Due to the long-term nature of transmission projects, regulatory certainty is needed to obtain and maintain financing. With regard to financial challenges, transmission developers are frequently faced with low or negative free cash flows (internally generated cash less capital investments) for an extended period of time when embarking on transmission projects, given their heavy development costs and long lead times. These long lead times include pre-construction activities, such as development and siting approvals. Such financial challenges can put pressure on a utility's financial metrics that are used to determine interest rates and terms for accessing needed capital and may limit the ability to access capital on favorable terms. This potentially can drive up a utility's borrowing costs (if it can get access to capital at all) or limit a utility's overall capital expenditures. Since the cost of accessing capital ultimately is borne by customers, it is clearly in everyone's interest that this outcome be avoided.[34] Regulators should look for opportunities to provide certainty by maintaining and authorizing stable, long-term returns for transmission developers and owners to support timely development of beneficial and necessary transmission investments.

Prior to construction, transmission projects generally are evaluated using a Commission-approved transmission planning process, which rigorously evaluates the costs and benefits of each project, assesses the forecasted changes in regional supply and demand, and considers alternative solutions such as new generation or demand-side energy-efficiency measures.[35] Once projects are selected, they still are subject to additional evaluations as part of federal agency and state commission reviews and siting processes.

In some jurisdictions, projects also are subject to additional reviews in subsequent planning cycles and may be delayed, scaled back, or cancelled. In addition, there is a wide disparity in how different planning processes evaluate the benefits of transmission, with some jurisdictions evaluating a significant number of the benefits while others rely mainly on reliability or narrowly defined analyses. However, these reviews and benefit analyses contribute to the riskiness of developing efficient transmission projects.

Lengthy, complicated, and costly siting and permitting processes continue to be major barriers to installing new transmission lines and upgrading existing lines. Since multiple federal, state, and local government agencies often are involved in right-of-way authorizations and related environmental permitting, the lack of inter-agency coordination forms another obstacle to permitting and siting. The challenge of locating lines across states and across federal lands, coupled with targeted, strong opposition from a variety of public interest groups, make the process even more daunting. Rerouting lines occurs with regularity, which increases construction costs.

Federal agencies have agreed to coordinate permitting efforts on federal lands, and a Department of Energy (DOE)-led Rapid Response Team for Transmission has engaged in an effort to streamline the federal approvals for seven large-scale transmission projects. Yet, these efforts have not been implemented broadly yet to significantly reduce the permitting time and expedite permitting on federal lands.[36] Moreover, depending on the location, there may be demands to place transmission underground, which can increase cost and construction times dramatically.[37] This, when coupled with other things such as political challenges, exacerbates the already long lead times for developing transmission and adds another layer of financial risk.

Southern California Edison's Devers-Colorado River ("DCR") transmission line project illustrates the significant challenges that utilities face in developing transmission. The DCR project includes the construction of new 110-mile and 42-mile 500-kilovolt (kV) transmission lines and a new 500-kV switchyard to facilitate, primarily, the development of renewable generation resources. The project originally was estimated to cost $545.3 million (real $2005); however, this estimate has increased to $701.3 million (real $2005). The single largest drivers behind the cost increase are direct and indirect costs associated with extensive environmental measures, including costs for mitigation, land, and field monitors; the costs of preparing permits; notice-to-proceed requests; requests for variances and determinations of National Environmental Policy Act adequacy; addendums; project refinement reports; requests for temporary extra workspace; and the resources needed to prepare, review and process documents.

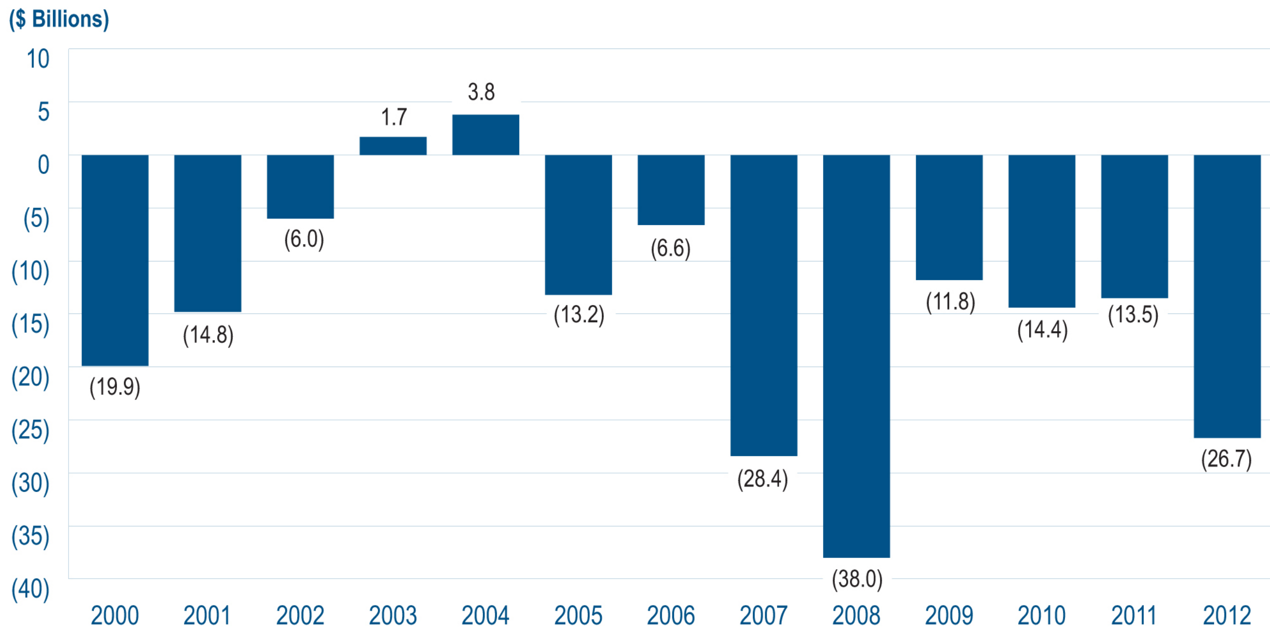
Another example of development challenges is the experience of joint-venture partners to develop the Prairie Wind project.[38] This project is a 110-mile, double-circuit 345-kV line with a projected cost of $225 million. Early in the planning stages, Prairie Wind briefly considered a route through the Red Hills area of Kansas, but rejected it due to concerns expressed by environmental groups, state and federal wildlife agencies, and landowners about a potential adverse impact on sensitive species and substantial additional costs for environmental remediation. Ultimately, the line had to be rerouted to avoid habitats of the lesser prairie chicken and a number of bat species.[39]

American Transmission Company's crossing of the Namekagon River as part of its Arrowhead-Weston 345-kV line tells a similar story. The Arrowhead-Weston Transmission Line Project is a 220-mile, 345-kV line built from Wausau, Wisconsin, to Duluth, Minnesota, to address what was at the time the second-most congested transmission seam in the Eastern Interconnection. The project needed to cross the Namekagon River, a wild and scenic river that is part of the St. Croix National Scenic Riverway, regulated by the National Park Service (NPS). Both a permit and an easement were needed prior to beginning construction. Although the river already was crossed by another utility's 161-kV line and two petroleum pipelines, obtaining the NPS permits took approximately 5.5 years and cost $3.9 million, almost twice the actual $2.0 million construction costs of the river crossing.

V. Transmission Investments Must Compete with Alternative Investment Opportunities

EEI members invested $90.5 billion in generation, transmission, and distribution systems in 2012 and are projected to invest approximately $85 billion annually through 2015 with the expectation of retaining currently existing ROEs.[40] Meanwhile, industry free cash flow, or internally generated cash flows less capital investments before financing, has been negative since 2005.[41] This requires utilities to access the equity and debt markets to fund investments. Moreover, transmission assets generate low levels of cash flows for reinvestment, since a primary source of cash flows from utility assets is depreciation, and many transmission assets are at the end of their depreciable lives. Therefore, access to equity capital in the financial markets to fund needed transmission is all the more critical as utilities work to maintain and/or expand their systems to meet customers' needs reliably and cost-effectively.

Industry Free Cash Flow



($ Billions)	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
Net Cash Provided by Operating Activities	42.1	55.4	56.3	57.0	58.1	50.2	69.4	61.1	61.3	82.9	77.7	84.4	84.2
Capital Expenditures	(47.4)	(57.2)	(49.0)	(43.0)	(41.1)	(48.4)	(59.9)	(74.1)	(82.8)	(77.6)	(74.2)	(78.6)	(90.5)
Dividends Paid to Common Shareholders	(14.6)	(13.1)	(13.4)	(12.3)	(13.2)	(15.1)	(16.1)	(15.4)	(16.5)	(17.1)	(18.0)	(19.3)	(20.5)
Free Cash Flow	**(19.9)**	**(14.8)**	**(6.0)**	**1.7**	**3.8**	**(13.2)**	**(6.6)**	**(28.4)**	**(38.0)**	**(11.8)**	**(14.4)**	**(13.5)**	**(26.7)**

Note: Totals may not equal sum of components due to rounding. Source: SNL Financial and EEI Finance Department

Utilities Compete Globally and with Other Industries for Capital

The ROE approved by FERC is intended to provide investors a return comparable to returns on similar investments of comparable risk. In order for utilities to attract capital to develop needed transmission, the ROE approved by FERC must be adequate and stable to attract investors and meet regulatory standards affirmed by the courts.[42] Investors only are willing to commit capital to utilities if they expect to earn a predictable return that is commensurate not only with the risks and challenges associated with developing transmission but also with the returns available to investments with comparable risks. It is both the level of return and the stability of that return that attract investment.

To the extent that FERC decisions result in a significant reduction of base ROEs after facilities have been placed into service, investors and financing entities will view future investment in the sector as less desirable, given the potential for unpredictable results as well as the diminished return. The result is that actions to reduce base ROEs have a magnifying effect of increasing investors' required cost of capital, further shrinking the available pool of funds for transmission investment.

Now is not the time to make significant reductions to ROEs on transmission investments. The competition for capital for infrastructure is growing, as illustrated by projected and significant capital needs in other industries. In addition to the electric power industry's capital expenditure needs, the American Petroleum Institute projects oil and natural gas industry investments of $5 trillion through 2035.[43] Also, a 2012 study on drinking water infrastructure needs estimates that the most urgent investments could be spread over 25 years at a cost of approximately $1 trillion.[44] There are other studies that identify infrastructure needs that will require significant amounts of capital.[45]

Apart from other investment opportunities in the energy industry, capital markets offer a wide variety of comparable risk alternatives in other sectors of the economy that compete with transmission investments for investors' scarce capital. As a result, there will be significant competing demands for capital and financing. If returns on electric transmission infrastructure are not sufficient and stable, investors will avoid such investments and instead will seek better and more stable returns elsewhere. For example, review of FERC's historical decisions indicates that, in 2011, FERC's approved ROEs for natural gas pipelines were 264 basis points higher, on average, than those of electric utilities and present alternative investment opportunities. ROEs proposed by complainants and FERC staff in current section 206 filings before the Commission would imply a dramatic and unwarranted increase in this differential.

Transmission Investments Compete with Alternative Utility Investments

As currently applied by the Commission, the DCF methodology results in transmission ROEs that are below currently authorized state ROEs. In some cases, these differences may amount to 200 or more basis points. For example, EEI data shows that the average state-approved ROE in 2012 was 10.15 percent, which—even being at the lowest in decades—is significantly above those under review and pending before FERC.[46]

Rational markets would not produce such significant and abrupt adjustments to existing ROEs; if anything, such anomalous results should signal that the Commission must reexamine its application of the DCF model and recognize that the model is not working in the current environment. As a result, changes to the DCF methodology and its evaluation of the results are needed. Rather than sending unintended investment signals with sharp downward adjustments to utilities' ROEs, the Commission should take the opportunity to consider the practical and necessary adjustments to its DCF methodology, as well as the insight offered by alternative approaches and the competition for capital.

With the needs for utilities not only to invest in ongoing transmission upgrades, but also generation and distribution system upgrades, it will be difficult for utilities to justify continued transmission investment, or to attract capital to such investment, if they cannot offer investors the opportunity to earn a fair, stable return. Transmission continues to be inherently more difficult to develop, construct, and operate than other areas of infrastructure development. As a result, transmission infrastructure development remains a pressing need across the country.

In determining a just and reasonable ROE, the Commission should consider state ROEs in relation to the result produced by the DCF methodology and its own policy goals related to transmission development. Such an approach would help to avoid undermining the progress that has been made in developing transmission by allowing the Commission to consider broader policy needs and the supporting actions necessary to achieve those results.

Capital markets are highly sophisticated and will move to risk-comparable investment opportunities with higher returns where such opportunity exists. FERC should give careful consideration to the competition for capital when determining just and reasonable ROEs for transmission, particularly where rigid application of the current DCF methodology leads to unsupported divergence between transmission ROEs and ROEs of risk-comparable utilities such as natural gas pipelines.

VI. FERC's Ratemaking Should Align with Its Public Policy Priorities

As required by the FPA, FERC must assure just and reasonable rates. In Order No. 1000, FERC adopted reforms, including a requirement that transmission providers consider needs driven by public policy goals in regional and interregional requirements in the planning processes. Public policy goals include cost-effective integration of renewable resources required under state statutes and voluntary guidelines. In particular, as noted, 29 states and the District of Columbia have set statutory deadlines to achieve these goals. In addition to these mandated deadlines, eight states have voluntary guidelines for development and integration of renewable resources.[47]

Compliance with state statutory goals will require additional transmission. Given the long lead times and risks, stable and compensatory ROEs are needed to ensure that the capital necessary to finance these and other projects is available. To ensure that ROEs remain sufficiently robust to support investment in this additional transmission, EEI recommends the Commission adopt the principles described in the following sections.

To Provide a More Stable Regulatory Framework for Investment, Requests to Lower Existing Returns Should Be Required to Demonstrate That These Returns Fall Outside of the Range of Reasonableness

Under section 206 of the FPA, parties requesting revisions to existing utility rates bear the burden of demonstrating that existing rates are not just and reasonable before FERC may consider whether a new rate should be established.[48] Accordingly, complainants must meet this initial burden of proof: specifically, they must show that the existing ROE falls outside of the statutory *range of reasonableness* in determining an ROE using the FERC-preferred DCF methodology. This range of reasonableness is bound by a low-end ROE calculation and a high-end ROE calculation, which result from the DCF financial model. The evaluation of whether an existing rate can be considered to be unjust and unreasonable should continue if, and only if, the complainant demonstrates the existing rate falls outside of this *range of reasonableness*. Without this standard, there is no real measure as to whether an existing rate is just and reasonable and calls into question every previously authorized return, depending on market conditions.

FERC's Analytical Method of Determining ROEs Should Not Be Allowed to Undermine Its Policy Objectives and Hinder Needed Transmission Investment

While FERC has relied solely on the results of a specific application of the DCF model to determine ROEs for electric transmission operations, dependence on a single, mechanical approach heightens the risk that the evidence considered by the Commission will not reflect realities in the capital markets accurately. The DCF methodology is a useful tool in estimating investors' requirements, but there is no "perfect" method to calculate a fair and reasonable ROE. Volatile and anomalous capital market conditions further increase the risks that a single, formulaic DCF application will not produce a just and reasonable ROE, particularly when those capital market conditions are the result of abnormal intervention.

There is considerable evidence that current financial market conditions spurred by the Federal Reserve's monetary policy in response to the 2008 recession seriously have undermined the Commission's ability to rely on its DCF approach as the sole determinant of a just and reasonable ROE. The results of FERC's DCF analysis, as it has evolved, can vary dramatically depending on:

- Whether the key metric of central tendency is the median or the midpoint;
- The makeup of the proxy group; and

- The criteria used to eliminate outliers.

Even when there is general agreement on these parameters, the DCF model can produce results that are not sufficient to support transmission investments and can undermine FERC's policy objectives. Legal precedent and the rule of reason support the Commission's careful consideration of current financial market conditions and the results of alternative methods. FERC should exercise flexibility, within or as an adjunct to, its existing DCF methodology, to account for the extraordinary financial environment now extant (*e.g.*, continuing Federal Reserve actions to stimulate the economy by keeping interest rates low, purchasing bonds,[49] etc.) and ensure that ROEs are sufficient to support needed transmission investment.

The Commission Must Recognize Limitations of the DCF Methodology and Adjust Implementation

Today's economic and financial conditions contribute to anomalous results in DCF analysis, as it currently is applied. Further, DCF proxy group result screens and other implementation aspects of the methodology that have been put into place over time have biased the DCF model to produce lower results in the current interest rate environment, which do not reflect financial market conditions in the future.

For example, Southern California Edison's experience with issuing preferred equity demonstrates that investors continue to expect returns that are well above current yields on Treasury securities. Although interest rates have fallen since 2008 as a result of the Federal Reserve's efforts to stimulate the economy, data on rates for preferred equity issued by Southern California Edison indicates that the cost of equity has not experienced a commensurate decline and remains much higher than the interest rates on Treasury securities. This is illustrated in the following table, which shows that the spreads between preferred equity issues and interest rates on Treasury securities have increased as much as 164 to 208 basis points.[50] In fact, the average rate for preferred equity issues increased by four basis points, notwithstanding significant declines in Treasury rates and FERC DCF estimates.[51]

SCE Preferred Equity Rates and Spreads, Before and After 2008

Issue Date	Preference Stock Issue	Projected/ Actual Preferred Coupon		30-Year Treasury Rate	Spread Over 30-Year Treasury		20-Year Treasury Rate	Spread Over 20-Year Treasury		10-Year Treasury Rate	Spread Over 10-Year Treasury
4/27/05	SCE Series A Preference Stock	5.349%	*	#N/A	#N/A		4.65%	0.70%		4.25%	1.10%
9/21/05	SCE Series B Preference Stock	6.125%		#N/A	#N/A		4.52%	1.61%		4.19%	1.94%
1/24/06	SCE Series C Preference Stock	6.00%		#N/A	#N/A		4.63%	1.37%		4.40%	1.60%
	Average Rate/Spread, Prior to 2008	**5.82%**			**#N/A**			**1.22%**			**1.54%**
3/10/11	SCE Series D Preference Stock	6.50%	**	4.53%	1.97%		4.25%	2.25%		3.37%	3.13%
1/17/12	SCE Series E Preference Stock	6.25%	*/**	2.89%	3.36%		2.57%	3.68%		1.87%	4.38%
5/17/12	SCE Series F Preference Stock	5.625%	**	2.80%	2.83%		2.39%	3.24%		1.70%	3.93%
1/29/13	SCE Series G Preference Stock	5.100%	**	3.18%	1.92%		2.79%	2.31%		2.03%	3.07%
	Average Rate/Spread, After 2008	**5.87%**			**2.52%**			**2.87%**			**3.63%**
	Increase in Rate/Spread	**0.04%**						**1.64%**			**2.08%**
	* - Coupon rate floats after ten years										
	** - Cumulative preference stock										

Simply stated, the current DCF analyses may not produce results conducive to attracting the capital that utilities require to meet the need for increased transmission investment. This will make it considerably more challenging to achieve the goals of increased transmission set by Congress and FERC. Consistency in ROE determinations will help to ensure increased long-term capital flow to transmission infrastructure investment. Considering present dislocations in the capital markets, FERC should maintain flexibility in its analysis and exercise its discretion in determining ROEs to protect customers and to enable utilities to attract the necessary capital investment.

Such flexibility should reflect the fact that current utility bond yields are anomalous and are expected to increase significantly, primarily driven by Treasury bonds being artificially and historically low, due to federal intervention to restore economic growth. Nevertheless, investors' required equity risk premium above lower-risk bonds has expanded, making it greater than otherwise would be the case at a more "normal" interest rate level. Equity continues to be the riskiest form of security in a corporation, and investors will not purchase equity unless it provides a return that exceeds the yield on bonds by some amount consistent with investors' premium expectations.

Since investors' required equity risk premium has expanded under current economic conditions, EEI recommends enhancements to provide the Commission flexibility to accommodate shifts in capital market conditions, to ensure that its public policy goals are achieved, and to ensure that utilities can continue to make the level of transmission investment needed. EEI, along with several economic and financial experts in individual FERC proceedings, support the following recommendations:

- Consider the results of alternative approaches, such as the risk premium method and the capital asset pricing model. In addition, consider the results of the current DCF analysis performed on a proxy group of companies from other capital-intensive industries or low-risk firms from the competitive sector. The results of these alternative analyses may be used as benchmarks in evaluating a fair ROE from within the range of reasonableness established by the DCF method applied to electric utilities. This will allow FERC to better set base ROEs in the current environment in the upper end of the zone of reasonableness to offset distortion of the DCF analysis. In parallel, allow flexibility to set ROEs in the upper end of the range of reasonableness based on benchmarking results. (For example, if the results show the central tendency is consistently below other benchmarking methods, FERC should set the ROE to be comparable to the outcome of other methods.) Electric utilities do not compete just with other electric utilities for capital; they also compete with companies from other sectors of the economy.
- Increase the screen for low estimates in a proxy group to be higher, such as 200-300 basis points above the prevailing long-term utility bond yield; and/or incorporate *projected* bond yields and then apply the currently applicable 100-basis-point threshold.
- Recognize that low and high DCF values are independent estimates, and the fact that one is considered to be an outlier does not compromise the remaining estimate, as the two methods are independent of each other. FERC should discontinue its policy of removing both results for a company from the proxy group if only one DCF estimate is identified to be excluded.
- There should be a shorter period of time for excluding companies with a recent dividend cut. FERC's practice of a multi-year exclusion of these companies is unreasonable, especially in instances where the cut was related to an external one-time event (e.g., storm restoration). The DCF is a forward-looking model relying on data that is current, using data that is no more than six months old, and forecasted growth rates. Therefore, a dividend cut that occurred six months prior is reflected in the market price and a longer exclusion from the proxy groups is not warranted.

FERC should make these practical adjustments to its ROE methodology immediately to better align it with current market conditions and facilitate reasonable returns. Furthermore, these changes have the benefit of being relatively simple and straightforward and, therefore, should not require a significant overhaul of the DCF methodology.

VII. FERC Should Reaffirm Its Commitment to Transmission Investment by Ensuring Adequate and Stable ROEs Are Retained

Finally, the Commission must consider the long-term implications of compromising its policy of promoting transmission investment. The record shows that utilities responded to the Commission's policy of promoting transmission by increasing their investments in this area significantly to the benefit of wholesale markets, reliability, renewable integration, and customers nationwide. In addition, numerous utilities pursued the development of wholesale energy markets by joining ISOs and RTOs per Commission policy. For the Commission to backtrack now would signal to the utilities and investors that its policies lack stability and durability.

FERC must realize that utility decisions to make long-term investments, and investors' decisions to commit the capital to back such investments, depend on stable and predictable regulatory policies. If the Commission changes course now, the long-term implications will be significant and may be irreversible. Therefore, rather than undermine its stated policies supporting needed transmission investment, FERC should reaffirm its commitment to transmission investment by making necessary adjustments in its approach to setting a just and reasonable ROE for transmission investment.

Endnotes

1 EEI is the association of U.S. shareholder-owned electric utilities and affiliates worldwide. EEI's members own or operate approximately 70 percent of the electric industry assets in this country, including approximately 70 percent of the transmission facilities in our nation. EEI's diverse membership includes utilities operating in all regions, including in regions with Regional Transmission Organizations (RTOs) and Independent System Operators (ISOs) and companies supplying electricity at wholesale in all regions.

2 *See, e.g.,* Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, § 1241 (2005) (EPAct 2005).

3 *See, e.g.,* Announcement of the Rapid Response Team – Transmission Pilot Projects, Secretary Ken Salazar, "Transmission is a vital component of our nation's energy portfolio…serves as important links across our country to increase our power grid's capacity and reliability…This is the kind of critical infrastructure we should be working together to advance in order to create jobs and move our nation toward energy independence" (2011); Secretary Steven Chu, "To compete in the global economy, we need a modern electricity grid," "An upgraded electricity grid will give consumers choices while promoting energy savings, increasing energy efficiency, and fostering the growth of renewable energy resources" (2011); Announcement of Load Guarantee for One Nevada Transmission Line, Secretary Steven Chu "This project…is a win for the economy as well as for the environment."

4 *See, e.g.,* Chairman Jon Wellinghoff, Testimony before the House Energy and Commerce Committee Energy and Environment Subcommittee, "A robust electric transmission grid is essential to achieving the vision of an energy future that I believe most of us share." (2010); Commissioner Philip Moeller, Statement on Transmission Planning and Cost Allocation, Docket No. RM10-23-000, "By building needed transmission, our nation's transmission network can be maintained at reliability levels that are the envy of the world, while simultaneously improving consumer access to lower-cost power generation." (2011)

5 Sound regulatory economics and the standards for determining compensatory returns are set forth by the Supreme Court in [*Bluefield* (*Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679 (1923)] and *Hope* [*FPC v. Hope Natural Gas Co*., 320 U.S. 591 (1944)], specifically, that a utility's allowed return on common equity should be sufficient to: (1) fairly compensate investors for capital they have invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

6 Actual expenditures are from EEI's Annual Property & Plant Capital Investment Survey and FERC Form 1s.

7 *Promoting Transmission Investment through Pricing Reform*, Order No. 679, FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, FERC Stats. & Regs. ¶ 31,236 (2007), *order on reh'g*, 119 FERC ¶61,062 (2007).

8 It is important to note that reliable integration of renewable resources, such as wind and solar, are dependent on a robust transmission grid.

9 While the transmission cost component may vary over time and by region, the Department of Energy recently estimated that transmission comprises 11 percent of a customer's bill. *See, e.g*., Energy Information Administration, http://www.eia.gov/energyexplained/index.cfm?page=electricity_factors_affecting_prices.

10 *See, i.e.,* ISO-NE Order No. 1000 compliance filing, ER193-000, October 25, 2012.

11 *See,* FERC Office of Enforcement, *2011 State of the Markets Report* (Apr. 19, 2012), available at: http://www.ferc.gov/market-oversight/reports-analyses/st-mkt-ovr/som-rpt-2011.pdf. In addition, it appears that the TrAIL project entering service in 2011 (along with some other transmission improvements) will reduce

congestion costs by about $1 billion in 2012. *See,* Figure 13.2 of the 2010 PJM RTEP Plan, available at: http://www.pjm.com/~/media/documents/reports/2010-rtep/2010-section13.ashx.

12 *See, e.g.,* MVPs Create Jobs, Benefits for States, available at: https://www.midwestiso.org/Library/Repository/Communication%20Material/Power%20Up/MVP%20Benefits%20-%20Total%20Footprint.pdf.

13 *See*, *e.g., The Economic Impacts of the August 2003 Blackout*, Electric Consumer Research Council, February 2, 2004. *See also, Average Cost of a Power Interruption in the U.S.*, source: LaCommare and Eto, 2004, available at: http://www.infrastructurereportcard.org/a/#e/power-interruptions This report includes estimates of average costs of a sustained outage, defined as a sustained interruption of 106 minutes or more.

14 *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 45 (2011) (Order No. 1000), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (Order No. 1000-A), *order on reh'g*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012) (Order No. 1000-B).

15 Order No. 1000 at PP 46, 497.

16 Federal Energy Regulatory Commission, The Strategic Plan - FY 2009-2014 at 3 (revised March 2013) available at http://www.ferc.gov/about/strat-docs/FY-09-14-strat-plan-print.pdf.

17 *See id*. at 22.

18 Letter to the Editor, *The Wall Street Journal*, January 10, 2011.

19 *See, e.g., PSE&G Working to Make NJ "Energy Strong,"* (announcing $3.9 billion, 10-year proposal to reduce power outages, stabilize customer bills, and create 5,800 jobs), available at: http://www.pseg.com/info/media/energy_strong/press_kit/index.jsp; *Washington, DC Mayor Gray Accepts Interim Report and Recommendations from Power Line Undergrounding Task Force* (announcing innovative plan, historic financing is expected to boost electric reliability by 95 percent), available at: http://mayor.dc.gov/release/mayor-gray-accepts-interim-report-and-recommendations-power-line-undergrounding-task-force.

20 *See* PJM Grid Operator Plans Billions In Transmission Improvements to Meet Massive Generator Fuel Shift, available at: http://pjm.com/~/media/about-pjm/newsroom/2013-releases/20130307-rtep_report_published.ashx.

21 AWEA: 2012 was 'best year ever' for wind in the U.S., transmission still a barrier, TransmissionHub (4/11/2013), available at: http://wiresgroup.com/docs/TransHub_AWEA_041213.pdf.

22 *Reliability Standards for the Bulk Electric System of North America* (updated March 12, 2013), available at: http://www.nerc.com/docs/standards/rs/Reliability_Standards_Complete_Set.pdf.

23 *See*, *e.g.,* Executive Order – Improving Critical Infrastructure Cybersecurity, available at: http://www.whitehouse.gov/the-press-office/2013/02/12/executive-order-improving-critical-infrastructure-cybersecurity.

24 Planned total industry expenditures are preliminary and are estimated from an 85-percent response rate to EEI's Electric Transmission Capital Budget & Forecast Survey.

25 A free copy of the report is available as an eBook and PDF on EEI's Web site at: http://www.eei.org/ourissues/ElectricityTransmission/Pages/TransmissionProjectsAt.aspx.

26 *Id*. (Some of these investments are also captured in EEI's total transmission investment projections through 2015.)

27 http://www.eei.org/ourissues/ElectricityGeneration/FuelDiversity/Documents/EEI_State_RES_Mandate_Table.pdf.

28 California Independent System Operator Corp., *2011 Annual State of the Grid Report*, at 17 (August 2011), available at: http://www.caiso.com/Documents/2011AnnualStateoftheGrid-20110817web.pdf. *Transmission Projects: At A Glance* (March 2013), at 126.

29 *See*, *Employment and Economic Benefits of Transmission Investment in the U.S. and Canada*, The Brattle Group, (May 2011), page ii.

30 Section 215 of EPAct 2005 requires a FERC-certified Electric Reliability Organization (ERO) to develop mandatory and enforceable Reliability Standards, which are subject to Commission review and approval. Once approved, the Reliability Standards may be enforced by the ERO, subject to FERC oversight or FERC can independently enforce Reliability Standards, Energy Policy Act of 2005, Pub. L. No 109-58, Title XII, Subtitle A, 119 Stat. 594, 941 (2005), 16 U.S.C. 824o.

31 As noted in *Transmission Projects: At A Glance,* most transmission projects in the report are multifaceted, addressing a range of needs and delivering a number of benefits. *See supra* note 26.

32 Order No. 1000 at p 4.

33 Order No. 1000 provides that certain transmission projects will be open to competition in the planning process and increases the risk of whether a particular project will be selected in the regional plan.

34 While there are certain project-specific rate treatments provided by FERC for qualifying projects, such as full rate base treatment for Construction Work in Progress, they do not fully mitigate the risks of the project for the transmission developer. These additional risks must be addressed by the developer in financing the project.

35 There are also merchant transmission projects that may result from voluntary contracts.

36 *See* Memorandum of Understanding among the nine federal agencies (October 2009), available at: http://energy.gov/sites/prod/files/Transmission%20Siting%20on%20Federal%20Lands%20MOU%20October%2023%2C%202009.pdf; Council of Environmental Quality, *Interagency Rapid Response Team for Transmission,* available at: http://www.whitehouse.gov/administration/eop/ceq/initiatives/interagency-rapid-response-team-for-transmission.

37 *See Out of Sight, Out of Mind 2012*: An Updated Study on the Undergrounding of Overhead Power Lines (January 2013) at pp. 30-33, prepared by Kenneth L. Hall, P.E. of Hall Energy Consulting, Inc. for Edison Electric Institute, available at: http://www.eei.org/ourissues/electricitydistribution/Documents/UndergroundReport.pdf.

38 This project is being jointly developed by Westar Corporation, American Electric Power, and MidAmerican Energy and approved by the Southwest Power Pool pursuant to its regional planning process.

39 *See* Prairie Wind Transmission, available at: http://www.westarenergy.com/wcm.nsf/resources/2011-6-29/$file/2011-6-29.pdf?openelement.

40 Fitch Ratings, "Corporate CapEx Study: Growth Stalls in 2013," October 25, 2012.

41 Free Cash Flow = Net Cash Provided from Operating Activities – Capital Expenditures – Dividends Paid to Common Shareholders. Sources: EEI Financial Department; company reports; SNL Financial.

42 *See Hope*, *Bluefield* discussed *supra*.

[43] *See* American Petroleum Institute "America's New Energy Future: The Unconventional Oil and Gas Revolution and the U.S. Economy" available at: http://www.ihs.com/info/ecc/a/americas-new-energy-future.aspx.

[44] *See, e.g., 2013 Report Card for America's Infrastructure*, American Society of Civil Engineers (2013), available at: http://www.infrastructurereportcard.org; citing a 2012 American Water Works report.

[45] *See* American Association of Railroads estimates $24.5 billion in freight rail investment in 2013, available at: https://www.aar.org/newsandevents/Press-Releases/Pages/Freight-Railroads-Plan-to-Invest-24-Billion-in-Private-Dollars-in-2013-On-Americas-Rail-Network-So-Taxpayers-Dont-Have-To.aspx

[46] *See* Financial Update, Quarterly Report of the U.S. Shareholder-Owned Electric Utility Industry (Q4 2012), available at: http://www.eei.org/whatwedo/DataAnalysis/IndusFinanAnalysis/Documents/2012_Q4_Rate_Case_Summary.pdf.

[47] *See* U.S. Department of Energy Database of State Incentives for Renewables & Efficiency (DSIRE), Renewable Portfolio Standard Policies (March 2013), available at: http://www.dsireusa.org/documents/summarymaps/RPS_map.pdf.

[48] *See, e.g., Nantahala Power & Light Co.*, 19 FERC ¶ 61,152, at 61,276 (1982); *Cal. Mun. Utils. Ass'n v. Cal. Indep. Sys. Operator Corp.*, 126 FERC ¶ 61,315 at PP 69-72 (2009); *Cities of Bethany, Bushnell, Cal. v. FERC*, 727 F.2d 1131, 1143 (D.C. Cir. 1984); *FPC v. Sierra Pacific Power Co.*, 350 U.S. 348, 353 (1956); *Cal. Indep. Sys. Operator Corp.*, 111 FERC ¶ 61,337, P 27 (2005).

[49] *See* Robert Mitkowski, Value Line, *Weak Jobs Report Gives Fed Cover to Continue Bond-Buying Program, but*… (Apr. 13, 2013) ("the Fed's extra-aggressive monetary policy…is creating extreme environments in segments of the economy. Those include the bond market…").

[50] It is reasonable to expect that common stock ROEs would show a similar increase relative to interest rates.

[51] While FERC's present DCF method does not incorporate Treasury rates directly, it does utilize utility bond yields as a cutoff for low estimates, and that cutoff does not incorporate this change in relative risk.

The **Edison Electric Institute (EEI)** is the association of U.S. shareholder-owned electric companies. Our members serve 95% of the ultimate customers in the shareholder-owned segment of the industry, and represent approximately 70% of the U.S. electric power industry. We also have as Affiliate members more than 80 International electric companies, and as Associate members more than 200 industry suppliers and related organizations.

Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas.

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701 Pennsylvania Ave., N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org