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UNITED STATES OF AMERICA
SURFACE TRANSPORTATION BOARD

STB Ex Parte No. 664 (Sub No. 2)

PETITION OF THE WESTERN COAL TRAFFIC LEAGUE TO INSTITUTE A RULEMAKING PROCEEDING TO ABOLISH THE USE OF THE MULTI-STAGE DISCOUNTED CASH FLOW MODEL IN DETERMINING THE RAILROAD INDUSTRY'S COST OF EQUITY CAPITAL

REPLY COMMENTS OF
NORFOLK SOUTHERN RAILWAY COMPANY

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Dated: November 4, 2014

BEFORE THE
SURFACE TRANSPORTATION BOARD

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Norfolk Southern ("NS") joins the reply comments of the Association of American Railroads in this proceeding and also files these separate comments for consideration. In these reply comments, NS makes the following five points. First, there is substantial overlap between the membership of the Western Coal Traffic League ("WCTL") and the Edison Electric Institute ("EEI"). Second, those members common to both groups are at best disingenuous with the Board in this proceeding – taking positions here that are different than the positions they take before their own regulators. Third, the comments and arguments EEI has published support the points made by NS and other railroad parties in the opening comments (and contradicts points made by the WCTL) -- namely: (1) the cost of equity ("COE") is elusive; (2) different models produce different COEs and even the same model can produce different COE's depending on the assumptions; and (3) there is a risk that a single model will not produce a reasonable estimate of the COE. Fourth, testimony and arguments of utilities that are not part of WCTL or EEI to their own regulators also support the railroads' position in this proceeding. Fifth, further investment in any industry depends on an adequate return on equity. NS elaborates on these points below.

First, there is substantial overlap in the membership of WCTL and EEI. In footnote 1 to WCTL's opening comments, WCTL lists fifteen member companies. Of those fifteen, seven are members of EEI, including: Ameren Missouri, CLECO Corporation, Entergy Services, Inc., Kansas City Power and Light Company, MidAmerican Energy Company, and Wisconsin Public Service Corporation.[1]

Second, despite similar members, WCTL's positions here are contrary in many ways to the positions taken by EEI before WCTL's members' own regulators. Thus, Allied Shippers, which includes WCTL and its members, made the specious comment that "whether a modification is suggested with respect to a component of the current test . . . or a new or additional criterion, if the effect is to make the railroads look less health financially it can be assumed that the proponent is results-oriented away from revenue adequacy, and the change should not be adopted."[2] This statement is truly ironic because the inconsistency between the comments they have filed here and the comments filed before their own regulator proves they are not principled and are merely results-oriented here.

For example, in June 2013, EEI defended the discounted cash flow ("DCF") model used by the Federal Energy Regulatory Commission ("FERC") as "a useful tool in estimating investors' requirements . . ." To reiterate, WCTL's members other industry

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1 *See* Exhibit A, map of EEI member companies, attached hereto and made a part hereof.

2 Joint Opening Comments of the Western Coal Traffic League, Consumers Energy Co., and South Mississippi Electric Power Association, Railroad Revenue Adequacy, Ex Parte 722, at 26 (Sept. 5, 2014).

organization, EEI, defended the use of a DCF methodology by FERC as one element in a sound approach to calculate the cost of equity.[3]

Similarly, EEI did not ask the FERC to abandon the use of a DCF in the comments it submitted to the FERC in 2006. Rather, it confirmed exactly what the AAR, NS, and others have said here. EEI urged the FERC to "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 model."[4] Note that EEI did not advocate the abolition of the DCF by the FERC to regulate its WCTL's members.[5] It advocated the use of DCF with other models, including CAPM.[6]

But EEI did not stop there. Recognizing that the FERC must provide for a "return on equity that attracts new investment in transmission facilities," EEI argued for "adders." "An ROE adder is a basis point increase above the Commission-approved

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3 EEI, *Transmission Investment, Adequacy Returns and Regulatory Certainty Are Key,* at 12 (June 2013), available at http://www.google.com/url?url=http://www.eei.org/issuesandpolicy/transmission/Documents/transmission_investment.pdf&rct=j&frm=1&q=&esrc=s&sa=U&ei=C4T_U5m3IYSvggShoIF4&ved=0CBQQFjAA&usg=AFQjCNHOH56YEcBCxAX0dozXqSDERPQLew (attached hereto and made a part hereof as Exhibit B).

4 Comments of the Edison Electric Institute on the Notice of Proposed Rulemaking Promoting Transmission Investment Through Pricing Reform, Docket No. RM06-4-000, at 14 (Jan. 11, 2006) ("EEI 2006 FERC Comment") available at http://www.eei.org/issuesandpolicy/testimony-filings-briefs/Documents/060111OwensFercTransmission.pdf.

5 *See* Exhibit B at 12.

6 Indeed, only a few years ago, WCTL similarly advocated for the Board to "use both a multi-state DCF and CAPM method to derive the cost-of-equity component of the cost of capital." *Methodology to Be Employed in Determining the Railroad Industry's Cost of Capital*, STB Docket No. Ex Parte 664, at 3 (Aug. 14, 2007).

ROE component of a public utility's allowed return."[7] In short, rather than arguing that its own regulator should establish the lowest possible cost of equity and criticizing its agency for calculating an ROE that was too high, EEI sought higher ROE calculations for its new transmission (i.e. infrastructure) projects.

Why the contrasting position here from these companies? WCTL answers this question for us. It is not searching for accuracy in the estimate of the cost of capital in this proceeding; it is simply seeking the lowest cost of capital possible from the STB for railroads. WCTL contends that the STB "substantially improved its methodology" in 2008 not because of some underlying principle but because "the change produced an immediate decline in the COE from 15.18% in 2005 under the SSDCF to 11.13% in 2006 under the CAPM." These companies would never say that at the FERC because they know among other things that:

(1) "An allowed ROE that is set below the return in capital markets on alternative investments of equivalent risk will constrain greater capital investment. . . "[8]

(2) "The nation is in a unique economic situation, as the Federal Reserve and other government policies have reduced the costs 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."[9]

(3) "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."[10]

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7 EEI 2006 FERC Comment at 10.

8 EEI 2006 FERC Comment at 13.

9 Exhibit B at 1 (emphasis added).

10 Exhibit B at 2 (emphasis added).

(4) "It is critical that FERC stay the course and provide regulatory certainty and adequate returns by making a few simple [upward] 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."[11]

Third, when these companies are advocating for what is in their best interest before FERC, their story sounds a lot like what the railroad parties have said in this proceeding.

- The Board has recognized that the COE is elusive.[12] EEI specifically agreed that "there is no 'perfect' method to calculate a fair and reasonable ROE."[13]
- Even when one model is used to estimate the COE, that one model can produce different results depending on the assumptions put into the model. Again, EEI is insightful because it knows that the results of COE calculations vary depending on which model is used and that even the same model will produce different results depending on the assumptions used:

> Of course, commissions will be faced with conflicting points of view as to exactly how high the cost of capital may be for a regulated company. *It is frequently the case that the costs of capital recommendations by intervenor and company expert witnesses diverge widely due to differences in implementation of estimation models, differences in samples, and differences in analysis of the data.*[14]

- There is a risk that a single model will not produce a reasonable estimate of the COE. Again, EEI is in agreement. "Volatile and anomalous capital

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11 Exhibit B at 2.

12 Ex Parte 664 (Sub-No. 1) at 15.

13 Exhibit B at 12.

14 The Edison Electric Institute, The Effect of Debt on the Cost of Equity: In a Regulatory Setting at 1 (January 2005), available at: http://www.eei.org/issuesandpolicy/stateregulation/Documents/effect_of_debt_final.pdf (emphasis added).

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."[15]

- Regulatory consistency is also important. In EEI's words, "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*."[16] Although WCTL would like to continue to pursue the flavor of the month year-after-year, constantly chasing the lowest COE estimate possible is not in the public interest.

Fourth, at least several utilities generally agree with the railroads' position in this proceeding. For example, Wisconsin Electric Power Company sought in 2009 a tariff increase from the Michigan Public Service Commission. One of its witnesses was Mary L. Wolter, a Business Consultant in the Finance Department of Wisconsin Electric Power Company. One of the points she made was that "[e]stimating the cost of equity is complicated because of the very nature of equity."[17] She went on to advocate as follows:

> As we have said, the cost of the equity invested in one asset is the earnings that the investor expects to forego by not investing in alternative assets. These expected earnings on alternative assets cannot be directly observed, so also the cost of equity cannot be directly observed. The various methods and calculations are proxies we use to try to estimate something that is not directly observable. Because no one model can be expected to arrive at a single "right answer", it is common in utility rate proceedings to use several different models and compare or combine the results in order to determine a reasonable estimate of the cost of equity.[18]

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15 Exhibit B at 12.

16 Exhibit B at 15 (emphasis added).

17 Statement of Mary L. Wolter at 16, available at https://efile.mpsc.state.mi.us/efile/docs/15981/0001.pdf

18 *Id.* at 17.

Ms. Wolter's submission even included a DCF model.

Similarly, Delmarva Power and Light Company hired Roger A. Morin, Professor of Finance at the College of Business, Georgia State University, as an expert in one of its rate proceedings in Maryland. His testimony also confirms the railroads' position here.

> . . . when measuring equity costs, which essentially deals with the measurement of investor expectations, no one single methodology provides a foolproof panacea. Each methodology requires the exercise of considerable judgment on the reasonableness of the assumptions underlying the methodology and on the reasonableness of the proxies used to validate the theory. . . It follows that more than one methodology should be employed in arriving at a judgment on the cost of equity and that these methodologies should be applied across a series of comparable risk companies.
>
> There is no single model that conclusively determines or estimates the expected return for an individual firm. Each methodology possesses its own way of examining investor behavior, its own premises, and its own set of simplifications of reality. Each method proceeds from different fundamental premises which cannot be validated empirically. Investors do not necessarily subscribe to any one method, nor does the stock price reflect the application of any one single method by the price-setting investor.
>
> There is no monopoly as to which method is used by investors. Absent any hard evidence as to which method outdoes the other, all relevant evidence should be used and equally weighted, in order to minimize judgmental error, measurement error, and conceptual infirmities. [19]

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[19] Rebuttal Testimony of Roger A. Morin for Delmarva Power and Light Co., Case No. 9093 Before the Public Service Commission of Maryland, at 17-18 (Mar. 2007) available at: http://www.google.com/url?url=http://psc.state.md.us/Intranet/Casenum/NewIndex3_VOpenFile.cfm%3Ffilepath%3DC:%255CCasenum%255C9000-9099%255C9093%255CItem_46%255C%255CCase9093DelmarvaRebuttalTestimonyofRogerA.Morin.pdf&rct=j&frm=1&q=&esrc=s&sa=U&ei=X-k_VJDmIsjLgwSFh4K4Aw&ved=0CBQQFjAA&usg=AFQjCNED-q8EyFWeoZriDKUHHWH8aNNIWg. Professor Morin notes in other testimony that he has testified before "nearly fifty (50) regulatory bodies in North America." Direct Testimony of Roger A. Morin, Ph.d., Application of Consolidated Edison Co. of N.Y. for an Increase in Electric Rates, Case No. 09-E-000, Before the New York State Public Service Commission, at 2 (2009), available at http://media.corporate-ir.net/media_files/irol/61/61493/050809/Roger_A._Morin.pdf (hereinafter "Morin, N.Y. Public Service Commission").

But that was not Professor Morin's only foray into explaining why the use of a single model – as advocated here by WCTL – is a bad idea. He has also stated the following: "As a general proposition, it is extremely dangerous to rely on only one generic methodology to estimate equity costs. The difficulty is compounded when only one variant of that methodology is employed. It is compounded even further when that one methodology is applied to a single company. Hence, several methodologies applied to several comparable risk companies should be employed to estimate the cost of common equity."[20]

Northern States Power, a subsidiary of Xcel Energy, has also provided expert testimony on the cost of equity that is similar to what the railroads have said here. Mr. Benderly, Xcel's expert, testified as follows:

> **Do you believe it is reasonable to employ several approaches for estimating the cost of equity?**
> A. Yes. The cost of equity is not directly observable in the marketplace. Therefore, to estimate the cost of equity, one must take cognizance of financial theory, the legal and regulatory framework for ratemaking and investor perceptions and judgments. There is no one approach that is now recognized, or should be recognized, as the best way to determine the cost of equity. Finally, because I believe there is a large potential for measurement error in determining the cost of equity of an electric utility, using multiple methodologies makes sense.[21]

[20] Morin, N.Y. Public Service Commission at 17. In another proceeding he said – word-for-word—the same thing. Prepared Direct Testimony of Roger A. Morin, Phd. For San Diego Gas and Electric Co., Before the Public Utilities Commission of California, Application A1204016 at 17 (Apr. 20, 2012), available at https://www.sdge.com/sites/default/files/regulatory/SDGE-Direct-Testimony-Roger-Morin.pdf.

[21] Direct Testimony of Zvi Benderly, Application of Northern States Power Company, a Wisconsin Corporation, for Authority to Adjust Electric and Natural Gas Rates, Public Service Commission of Wisconsin, Docket No. 4220-UR-116 at 43, available at http://www.xcelenergy.com/staticfiles/xe/Regulatory/WiRateCaseDirectBenderly.pdf.

He went on to confirm that the academic literature supported the use of multiple models. In response to the question "Is there support in the analytical literature for the need to rely upon multiple cost of-equity models in arriving at a cost of equity estimate," he answered as follows: "Yes, the financial literature supports the use of multiple methods."[22] He then continued by quoting Professor Stewart Myers statement in which Professor Myers said: "Use more than one model when you can....That means you should not use any one model or measure mechanically and exclusively. Beta is helpful as one tool in a kit, to be used in parallel with DCF models or other techniques for interpreting capital market data. There are other noted academicians who explain that no one individual method provides sufficient precision for arriving at a definitive estimate of the cost of equity."[23] Indeed, Mr. Benderly's submission even included a DCF model.[24]

Fifth, EEI confirms investment in any industry depends on the ability to earn adequate returns. The reason that EEI sought higher ROEs as well as "adders" is enlightening even in the railroad context.

> 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.[25]

Stated differently, any model "can produce results that are not sufficient to support transmission investments."[26] In more of EEI's words, "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

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22 *Id.* at 44.

23 *Id.*

24 *Id.* at 59-67.

25 Exhibit B at 15.

26 Exhibit B at 13.

project construction timeline and the 30-40 year life of the transmission asset."[27] Given these statements, it is clear that there should be agreement that unprincipled attempts to lower the COE, which is used in a variety of ways by the STB such as in stand-alone rate cases, are inconsistent with calls by politicians and shippers at the recent service hearings[28] and in recent Senate hearings[29] for railroads to invest in more capacity.

To be clear, NS is not contending that utilities and railroads themselves, or the regulatory systems for utilities and railroads, are similar. Indeed, the Board knows better.[30] Courts do too.[31] However, utility regulators – like the Board – search for a

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[27] Reply Comments of the Edison Electric Institute, Docket No RM11-26-000, at 8 (May 21, 2012), available at http://www.stoppathwv.com/documents/eei-comments.pdf.

[28] Testimony of U.S. Senator John Hoeven, EP 724, United States Rail Service Issues (Sept. 4, 2014) ("We need more capacity in terms of track. We need a bigger railroad. We need more track."); Testimony of North Dakota State Senator Tyler Axness, EP 724, United States Rail Service Issues (Sept. 4, 2014) (urging railroads to "undertake the investment to provide the service that is expected of them"); Testimony of Hal Clemensen, South Dakota Wheat Growers Cooperative, EP 724 United States Rail Service Issues (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"); Testimony of Lucas Lentsch, Secretary of Agriculture, State of South Dakota, EP 724 United States Rail Service Issues (Apr. 10, 2014) ("Farmers spent the capital to increase production, grain companies have spent the capital to handle this new production, and now it is up to railroads to spend the capital to get this production to export. . . . *And now is the time to build up the railroad infrastructure to handle this increased production.*") (emphasis added); Comments of Minnesota Grain and Feed Association at 2-3, EP 724 United States Rail Service Issues (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.").

[29] Statement of U.S. Senator John Hoeven, Freight Rail Service: Improving the Performance of America's Rail System, Committee on Commerce, Science, and Transportation, U.S. Senate (Sept. 10, 2014) ("Railroads need to bring more resources to meet the needs of North Dakota. . . . We need more capacity on the part of the railroads. . . They need to bring more cars, more locomotives, and more people, and they need to build more track."); Statement of U.S. Senator Heidi Heitkamp, Freight Rail Service: Improving the Performance of America's Rail System, Committee on Commerce, Science, and Transportation, U.S. Senate (Sept. 10, 2014) ("Need a response in dollars from the railroads.").

[30] *See e.g.*, *Western Coal Traffic League – Petition for Declaratory Order*, Docket FD 35506 (July 25, 2013) ("Congress deliberately chose to move away from a public

measure of the cost of equity. And what the utilities tell their own regulators is both enlightening and quite different than what they say in this proceeding.

Respectfully Submitted,

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utility model of regulation for the railroad industry. Before 1976, consistent with the public utility model of regulation, the ICC 'was charged with examining *every* railroad shipping rate to ensure that it was 'just and reasonable.'' *Ass'n of Am. R.Rs. v. STB*, 237 F.3d 676, 677 (D.C. Cir. 2001)."; *see also Arkansas Power & Light Co. Petition to Institute Rulemaking Proceeding – Implementation of Long-Cannon Amendment to the Staggers Rail Act*, 365 I.C.C. 983, 989 (1982) ("The Commission does not regulate the overall rate of return for railroads").

31 *Bessemer & Lake Erie Railroad Co. v. I.C.C.*, 691 F.2d 1104, 1113 (3rd Cir. 1982) ("Public utility regulation, by contrast, provides for an assured rate of return to regulated monopolies. In fixing an assured rate of return, it is not unfair to take into account only the embedded cost of debt. Railroad regulation by the ICC, is not, however, classic public utility regulation. For the most part railroads operate in a competitive environment. It is true that under the 4R and Staggers Acts they are subject to regulation of rates for market dominant traffic. They are not, however, assured of a compensable rate of return even on the investment required to serve that traffic.").

EXHIBIT A

Edison Electric Institute
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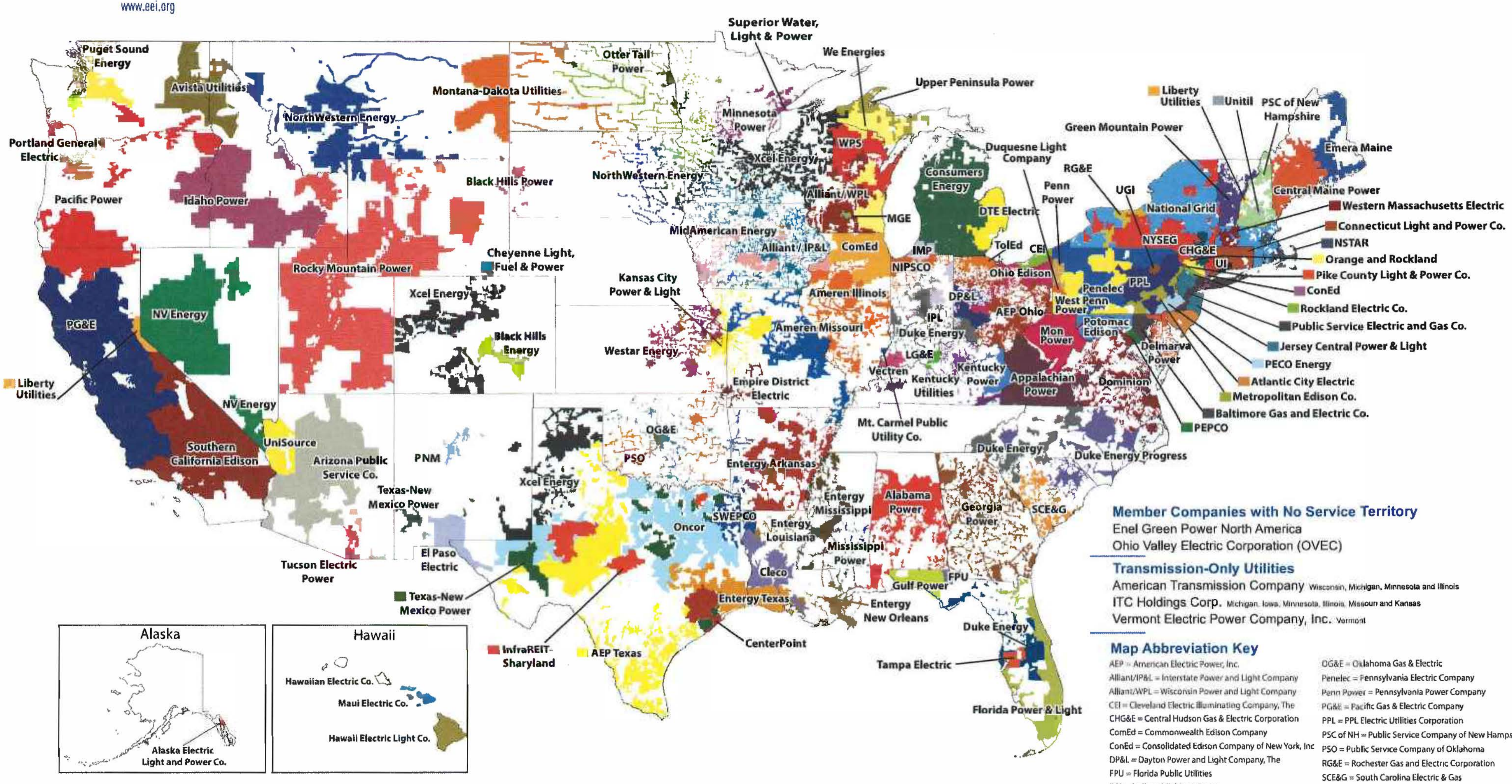
EEI U.S. Member Company Service Territories



Member Companies with No Service Territory

Enel Green Power North America
Ohio Valley Electric Corporation (OVEC)

Transmission-Only Utilities

American Transmission Company Wisconsin, Michigan, Minnesota and Illinois
ITC Holdings Corp. Michigan, Iowa, Minnesota, Illinois, Missouri and Kansas
Vermont Electric Power Company, Inc. Vermont

Map Abbreviation Key

AEP = American Electric Power, Inc.
Alliant/IP&L = Interstate Power and Light Company
Alliant/WPL = Wisconsin Power and Light Company
CEI = Cleveland Electric Illuminating Company, The
CHG&E = Central Hudson Gas & Electric Corporation
ComEd = Commonwealth Edison Company
ConEd = Consolidated Edison Company of New York, Inc
DP&L = Dayton Power and Light Company, The
FPU = Florida Public Utilities
IMP = Indiana Michigan Power
IPL = Indianapolis Power & Light Company
LG&E = Louisville Gas and Electric Company
MGE = Madison Gas and Electric Company
Mon Power = Monongahela Power
NYSEG = New York State Electric & Gas Corporation
NIPSCO = Northern Indiana Public Service Co.
OG&E = Oklahoma Gas & Electric
Penelec = Pennsylvania Electric Company
Penn Power = Pennsylvania Power Company
PG&E = Pacific Gas & Electric Company
PPL = PPL Electric Utilities Corporation
PSC of NH = Public Service Company of New Hampshire
PSO = Public Service Company of Oklahoma
RG&E = Rochester Gas and Electric Corporation
SCE&G = South Carolina Electric & Gas
SWEPCO = Southwestern Electric Power Company
ToIEd = Toledo Edison Company, The
UGI = UGI Utilities, Inc.
UI = United Illuminating Company, The
WPS = Wisconsin Public Service Corporation

Produced by Edison Electric Institute's Project Support Group. Data Source: Ventyx, The Velocity Suite 2014. - map updated August 2014

EEI Member Lookup By Operating Utility

AEP Ohio	American Electric Power, Inc.
AEP Texas	American Electric Power, Inc.
Alabama Power Company	Southern Company
Alaska Electric Light and Power Company	Avista Corporation
Ameren Illinois	Ameren Corporation
Ameren Missouri	Ameren Corporation
American Transmission Company	No Parent
Appalachian Power	American Electric Power, Inc.
Arizona Public Service Company	Pinnacle West Capital Corporation
Atlantic City Electric	Pepco Holdings, Inc.
Avista Utilities	Avista Corporation
Baltimore Gas and Electric Company	Exelon Corporation
Black Hills Energy	Black Hills Corporation
Black Hills Power	Black Hills Corporation
CenterPoint Energy, Inc.	No Parent
Central Hudson Gas & Electric Corporation	CH Energy Group, Inc.
Central Maine Power Company	Iberdrola USA
CH Energy Group, Inc.	Fortis Inc.
Cheyenne Light, Fuel & Power Company	Black Hills Corporation
Cleco Power LLC	Cleco Corporation
Cleveland Electric Illuminating Company, The	FirstEnergy Corp.
Commonwealth Edison Company	Exelon Corporation
Connecticut Light and Power Company, The	Northeast Utilities
Consolidated Edison Company of New York, Inc.	Consolidated Edison, Inc.
Consumers Energy	CMS Energy Corporation
Dayton Power and Light Company, The	AES Corporation
Delmarva Power	Pepco Holdings, Inc.
DTE Electric	DTE Energy Company
Dominion	No Parent
Duke Energy	No Parent
Duquesne Light Company	Duquesne Light Holdings, Inc.
El Paso Electric Company	No Parent
Emera Maine	Emera
Empire District Electric Company, The	No Parent
Enel Green Power North America	No Parent
Entergy Arkansas, Inc.	Entergy Corporation
Entergy Louisiana, Inc.	Entergy Corporation
Entergy Mississippi, Inc.	Entergy Corporation
Entergy New Orleans, Inc.	Entergy Corporation
Entergy Texas, Inc.	Entergy Corporation
Fitchburg Gas & Electric Light Company	Unitil
Florida Power & Light Company	NextEra Energy, Inc.
Florida Public Utilities Company	Chesapeake Utilities Corporation
Georgia Power Company	Southern Company
Green Mountain Power	Gaz Métro
Gulf Power Company	Southern Company
Hawaii Electric Light Company	Hawaiian Electric Industries
Hawaiian Electric Company	Hawaii Electric Light Company
Idaho Power Company	IDACORP, Inc.
Indiana Michigan Power	American Electric Power, Inc.
Indianapolis Power & Light Company	AES Corporation
InfraREIT-Sharyland	No Parent
Interstate Power and Light Company	Alliant Energy Corporation
ITC Great Plains	ITC Holdings Corp.
ITC Midwest	ITC Holdings Corp.
ITC Transmission	ITC Holdings Corp.
Jersey Central Power & Light Company	FirstEnergy Corp.
Kansas City Power & Light Company	Great Plains Energy, Inc.
Kentucky Power	American Electric Power, Inc.
Kentucky Utilities Company	LG&E and KU Energy
LG&E and KU Energy	PPL Corporation
Liberty Utilities	No Parent
Louisville Gas and Electric Company	LG&E and KU Energy
Madison Gas and Electric Company	MGE Energy, Inc.
Maui Electric Company, Ltd.	Hawaiian Electric Light Company
Metropolitan Edison Company	FirstEnergy Corp.
Michigan Electric Transmission Company, LLC	ITC Holdings Corp.
MidAmerican Energy Company	Berkshire Hathaway Energy
Minnesota Power	ALLETE
Mississippi Power Company	Southern Company
Monongahela Power	FirstEnergy Corp.
Montana-Dakota Utilities	MDU Resources Group, Inc.
Mt. Carmel Public Utility Company	No Parent
National Grid	No Parent
New York State Electric & Gas Corporation	Iberdrola USA
Northern Indiana Public Service Co (NIPSCO)	NiSource Inc.
NorthWestern Energy	No Parent
NSTAR	Northeast Utilities
NV Energy	Berkshire Hathaway Energy
OG&E Electric Services	OGE Energy Corporation
Ohio Edison Company	FirstEnergy Corp.
Ohio Valley Electric Corporation (OVEC)	No Parent
Oncor	Energy Future Holdings
Orange and Rockland Utilities, Inc.	Consolidated Edison, Inc.
Otter Tail Power Company	Otter Tail Corporation
Pacific Gas & Electric Company	PG&E Corporation
Pacific Power	PacifiCorp
PacifiCorp	Berkshire Hathaway Energy
PECO Energy	Exelon Corporation
Pennsylvania Electric Company	FirstEnergy Corp.
Pennsylvania Power Company	FirstEnergy Corp.
Pepco	Pepco Holdings, Inc.
Pike County Light & Power Company	Orange and Rockland Utilities, Inc.
PNM	PNM Resources, Inc.
Portland General Electric	No Parent
Potomac Edison	FirstEnergy Corp.
PPL Electric Utilities Corporation	PPL Corporation
Public Service of New Hampshire	Northeast Utilities
Public Service Company of Oklahoma	American Electric Power, Inc.
Public Service Electric and Gas Company	Public Service Enterprise Group, Inc.
Puget Sound Energy	Puget Energy, Inc.
Rochester Gas and Electric Corporation	Iberdrola USA
Rockland Electric Company	Orange and Rockland Utilities, Inc.
Rocky Mountain Power	PacifiCorp
South Carolina Electric & Gas Company	SCANA Corporation
Southern California Edison Company	Edison International
Southwestern Electric Power Company	American Electric Power, Inc.
Superior Water, Light and Power Company	ALLETE
Tampa Electric Company	TECO Energy, Inc.
Texas-New Mexico Power Company	PNM Resources, Inc.
Toledo Edison Company, The	FirstEnergy Corp.
Tucson Electric Power Company	UNS Energy Corporation
UGI Utilities, Inc.	UGI Corporation
UniSource Energy Services	UNS Energy Corporation
United Illuminating Company, The	UIL Holdings Corporation
Unitil Energy System, Inc.	Unitil
Upper Peninsula Power Company	Integrys Energy Group
Vectren Energy Delivery-South	Vectren Corporation
Vermont Electric Power Company, Inc.	No Parent
We Energies	Wisconsin Energy Corporation
West Penn Power	FirstEnergy Corp.
Westar Energy Inc.	No Parent
Western Massachusetts Electric Company	Northeast Utilities
Wisconsin Power and Light Company	Alliant Energy Corporation
Wisconsin Public Service Corporation	Integrys Energy Group
Xcel Energy Inc.	No Parent

EEI Member Lookup By Parent Company

AES Corporation
- Dayton Power and Light
- Indianapolis Power & Light Company

ALLETE
- Minnesota Power
- Superior Water, Light and Power Company

Alliant Energy Corporation
- Interstate Power and Light Company
- Wisconsin Power and Light Company

Ameren Corporation
- Ameren Illinois
- Ameren Missouri

American Electric Power, Inc.
- AEP Ohio
- AEP Texas
- Appalachian Power
- Indiana Michigan Power
- Kentucky Power
- Public Service Company of Oklahoma
- Southwestern Electric Power Company

American Transmission Company

Avista Corporation
- Alaska Electric Light and Power Company
- Avista Utilities

Berkshire Hathaway Energy
- MidAmerican Energy Company
- NV Energy
- PacifiCorp
  - Pacific Power
  - Rocky Mountain Power

Black Hills Corporation
- Black Hills Energy
- Black Hills Power
- Cheyenne Light, Fuel & Power Company

CenterPoint Energy, Inc.

Chesapeake Utilities Company
- Florida Public Utilities Company

Cleco Corporation
- Cleco Power LLC

CMS Energy Corporation
- Consumers Energy

Consolidated Edison, Inc.
- Consolidated Edison Company of New York, Inc.
- Orange and Rockland Utilities, Inc.
  - Pike County Light & Power Company
  - Rockland Electric Company

Dominion

DTE Energy Company
- DTE Electric

Duke Energy
- Duke Energy Progress

Duquesne Light Holdings, Inc.
- Duquesne Light Company

Edison International
- Southern California Edison Company

El Paso Electric Company

Emera
- Emera Maine

Empire District Electric Company, The

Enel Green Power North America

Energy Future Holdings
- Oncor

Entergy Corporation
- Entergy Arkansas, Inc.
- Entergy Louisiana, Inc.
- Entergy Mississippi, Inc.
- Entergy New Orleans, Inc.
- Entergy Texas, Inc.

Exelon Corporation
- Baltimore Gas and Electric Company
- Commonwealth Edison Company
- PECO Energy

FirstEnergy Corp.
- The Cleveland Electric Illuminating Company
- Jersey Central Power & Light Company
- Metropolitan Edison Company
- Monongahela Power
- Ohio Edison Company
- Pennsylvania Electric Company
- Pennsylvania Power Company
- Potomac Edison
- The Toledo Edison Company
- West Penn Power

Fortis Inc.
- CH Energy Group, Inc.
  - Central Hudson Gas & Electric Corporation

Gaz Métro
- Green Mountain Power

Great Plains Energy, Inc.
- Kansas City Power & Light Company

Hawaiian Electric Industries
- Hawaii Electric Light Company
  - Hawaiian Electric Company
  - Maui Electric Company, Ltd.

Iberdrola USA
- Central Maine Power Company
- New York State Electric & Gas Corporation
- Rochester Gas and Electric Corporation

IDACORP, Inc.
- Idaho Power Company

InfraREIT-Sharyland

Integrys Energy Group
- Upper Peninsula Power Company
- Wisconsin Public Service Corporation

ITC Holdings Corp.
- ITC Great Plains
- ITC Midwest
- ITC Transmission
- Michigan Electric Transmission Company, LLC (METC)

Liberty Utilities

MDU Resources Group, Inc.
- Montana-Dakota Utilities Co.

MGE Energy, Inc.
- Madison Gas and Electric Company

Mt. Carmel Public Utility Company

National Grid

NextEra Energy, Inc.
- Florida Power & Light Company

NiSource Inc.
- Northern Indiana Public Service Co (NIPSCO)

Northeast Utilities
- The Connecticut Light and Power Company
- NSTAR
- Public Service of New Hampshire
- Western Massachusetts Electric Company

NorthWestern Energy

OGE Energy Corporation
- OG&E Electric Services

Ohio Valley Electric Corporation (OVEC)

Otter Tail Corporation
- Otter Tail Power Company

Pepco Holdings, Inc.
- Atlantic City Electric
- Delmarva Power
- Pepco

PG&E Corporation
- Pacific Gas & Electric Company

Pinnacle West Capital Corporation
- Arizona Public Service Company

PNM Resources, Inc.
- PNM
- Texas-New Mexico Power Company

Portland General Electric

PPL Corporation
- LG&E and KU Energy
  - Kentucky Utilities Company
  - Louisville Gas and Electric Company
- PPL Electric Utilities

Public Service Enterprise Group, Inc.
- Public Service Electric and Gas Company

Puget Energy, Inc.
- Puget Sound Energy

SCANA Corporation
- South Carolina Electric & Gas Company

Southern Company
- Alabama Power Company
- Georgia Power Company
- Gulf Power Company
- Mississippi Power Company

TECO Energy, Inc.
- Tampa Electric Company

UGI Corporation
- UGI Utilities, Inc.

UIL Holdings Corporation
- The United Illuminating Company

Unitil
- Fitchburg Gas & Electric Light Company
- Unitil Energy System, Inc.

UNS Energy Corporation
- Tucson Electric Power Company
- UniSource Energy Services

Vectren Corporation
- Vectren Energy Delivery-South

Vermont Electric Power Company

Westar Energy Inc.

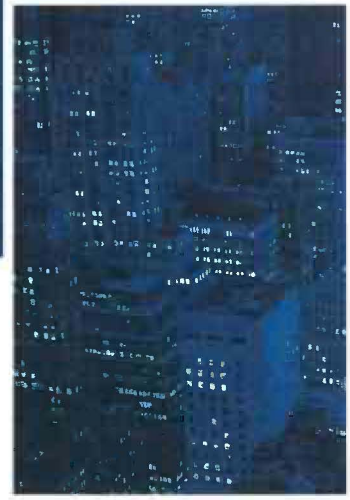
Wisconsin Energy Corporation
- We Energies

Xcel Energy Inc.

EXHIBIT B

Edison Electric Institute

Power by Association[SM]



Transmission Investment

Adequate Returns and Regulatory Certainty Are Key

June 2013

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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

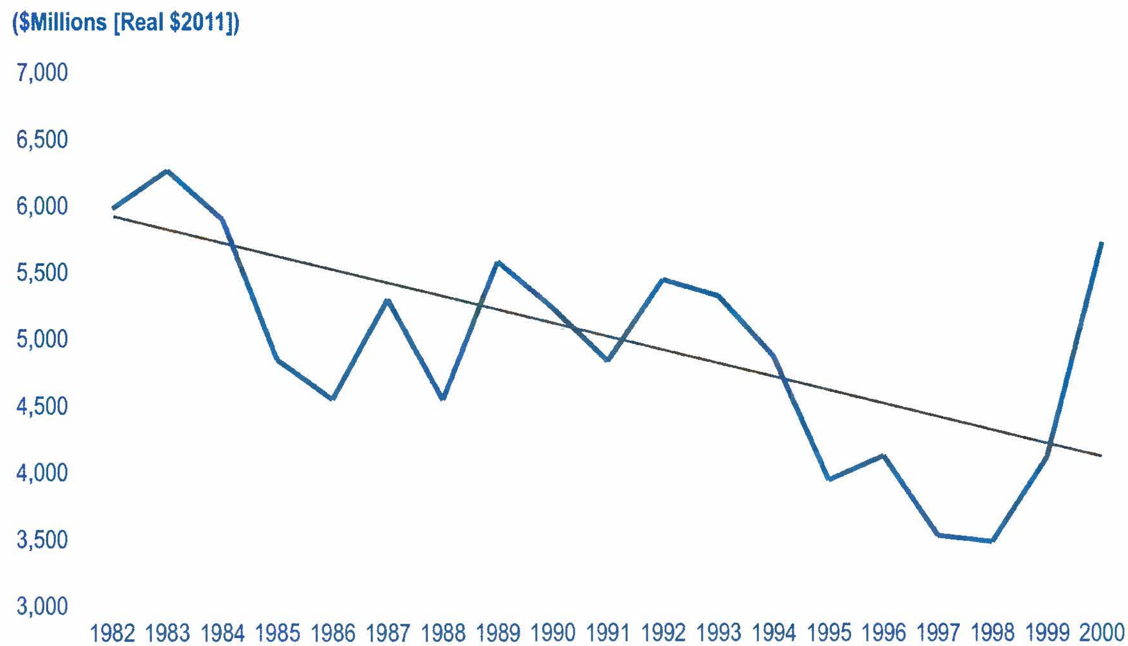
EEI's shareholder-owned electric utility members[1] are making cost-effective transmission investments to ensure that the power grid is reliable and efficient, meets 21st-century electricity needs, and supports competitive wholesale markets. There are numerous benefits of a robust transmission system, 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

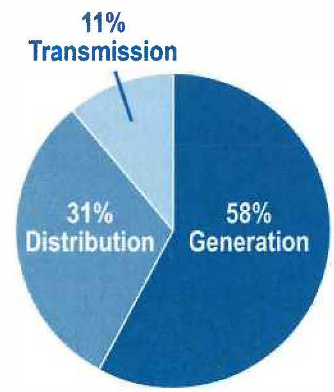
- A more resilient grid in the face of extreme weather events.

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]

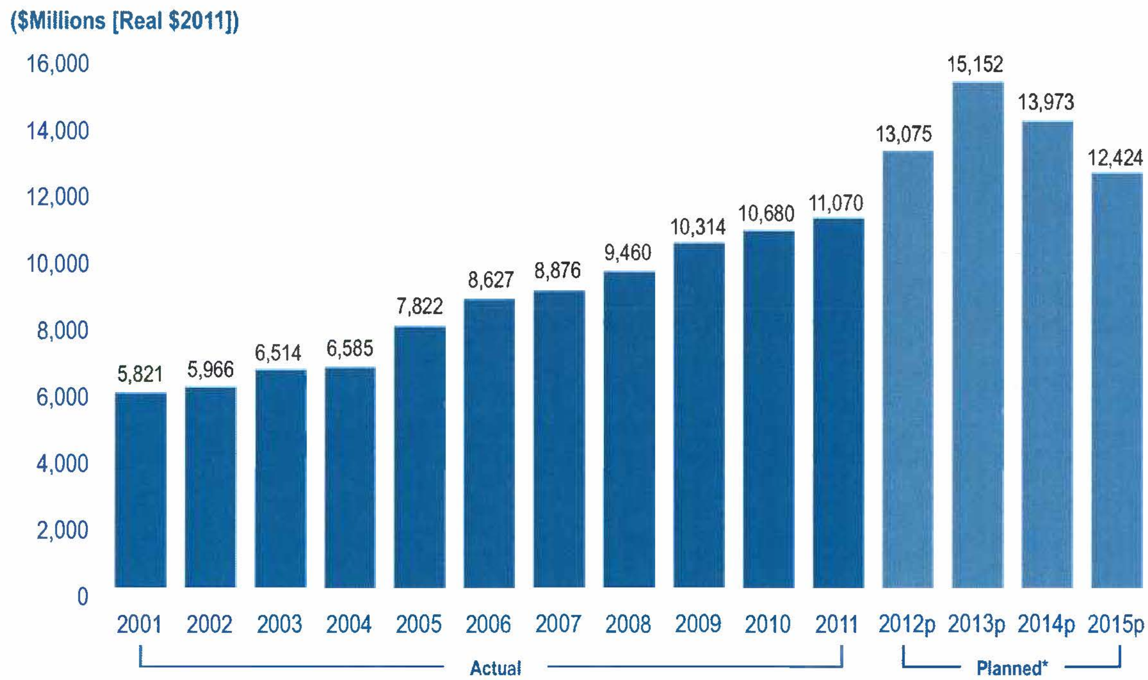
Meanwhile, the North American Electric Reliability Corporation (NERC) and FERC continue to develop and approve a growing list of mandatory standards aimed at ensuring Bulk Power System reliability, requiring incremental capital investments for all utilities that own transmission.[22] In addition, the 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.

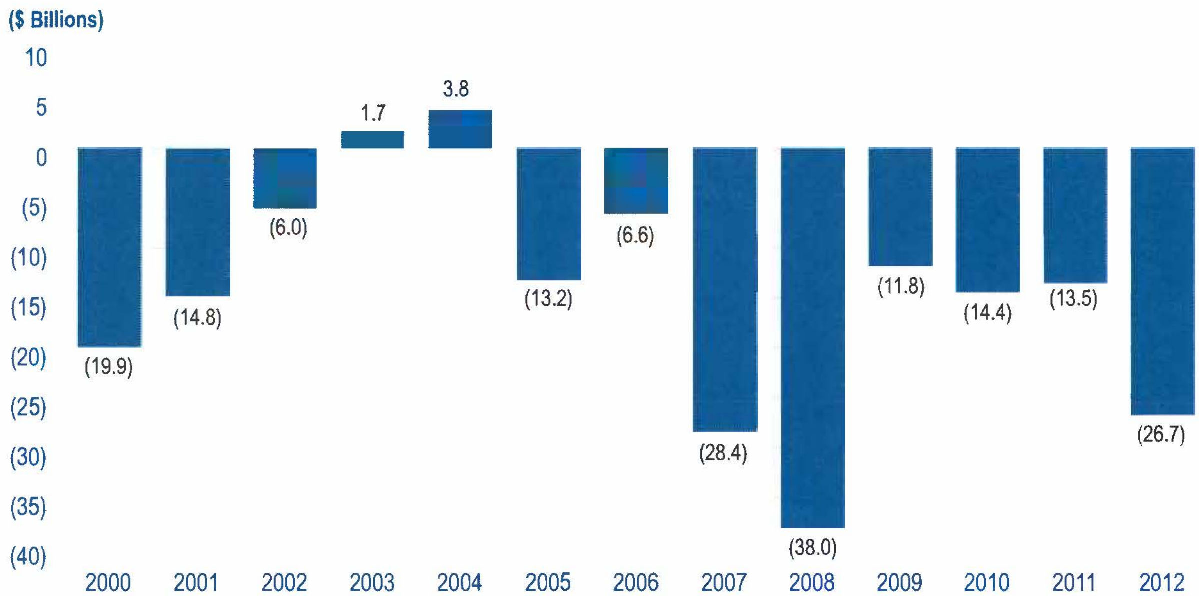
Another example of development challenges is the experience of joint-venture partners to develop the Prairie Wind project.[38] This project is a 110-mile, double-circuit 345-kV line with a projected cost of $225 million. Early in the planning stages, Prairie Wind briefly considered a route through the 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.

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