DIRECT TESTIMONY

OF

SETH PARKER

ON BEHALF OF

MISSISSIPPI PUBLIC UTILITIES STAFF

BEFORE THE MISSISSIPPI PUBLIC SERVICE COMMISSION

DOCKET NO. 2012-UA-358

June 20, 2013

TABLE OF CONTENTS

EXHIBITS

FIGURES

TABLES

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I. INTRODUCTION AND PURPOSE

Q. Please state your name and occupation.

A. I am Seth G. Parker, a Vice President and Principal of Levitan & Associates, Inc. ("LAI"), a management consulting firm specializing in the power and fuels markets. I have been with LAI since 1998.

Q. Please describe LAI.

A. LAI is an energy management consulting firm. LAI is located at 100 Summer Street, Suite 3200, Boston, MA 02110. Since its founding in 1989, LAI has conducted numerous power and fuel assignments throughout the U.S. and Canada. These assignments have encompassed diverse matters pertaining to generation and transmission project evaluations, market energy and capacity price forecasts, competitive market design, power plant valuation, bulk power security, generation resource, power supply, and fuel procurements, contracts, pipeline transportation, and risk management. LAI's clients include utilities, generation companies, gas suppliers, Independent System Operators ("ISOs") and Regional Transmission Organizations ("RTOs"), end-users, debt lenders, and equity investors. LAI has represented state regulatory commissions and other procurement entities in Connecticut, Maine, Maryland, California, Illinois, New York, and Rhode Island.

Q. Please describe your professional experience and qualifications.

A. I am an economic and financial manager with 35 years of international experience in power and fuel project development, evaluation, financing, and transactions. I have been responsible for modeling and analyses of independent and utility-owned generation and transmission projects, as well as market design, regulatory policy, contract restructuring, power economics, and asset valuation assignments in regulated and competitive power markets. These assignments have included establishing competitive market parameters that determine generator operations and revenues, energy and capacity price forecasts, and the array of risk factors affecting asset value. As a Vice President of LAI, I actively manage many of the firm's technical and commercial matters undertaken for our clients.

Q. What were your previous positions and your educational background?

A. Before joining LAI, I worked as a consultant and officer of Stone & Webster Management Consultants, Inc., an advisory firm that provided business, technical, strategic management, economic, financial, and regulatory consulting services in the power, fuels, and petrochemical industries. While at Stone & Webster, I was responsible for due diligence and market reviews of many proposed power, fuel, and infrastructure projects in the U.S. and abroad for commercial banks, investment banks, multilateral lending agencies, and other financial institutions. I have also worked in the Treasurer's Office at Pacific Gas & Electric, and have been involved in project development and financing activities at ThermoElectron Energy Systems and J. Makowski Associates, Inc.

My educational background includes an Sc.B. in Applied Mathematics / Economics from Brown University and an M.B.A. in Finance / Operation Research from the Wharton Graduate School at the University of Pennsylvania. I have taught undergraduate-level finance courses as an adjunct faculty lecturer and have taken additional course work in energy technology and geopolitics. My resume is provided as Exhibit SGP-1 and contains a list of my expert reports and testimony.

Q. What is the purpose of your testimony, and on whose behalf are you offering it?

A. The purpose of my testimony is to (i) evaluate the proposed Transaction as described in the Joint Application, its supporting documents, and interrogatory responses and (ii) to provide a fair and balanced view of the Transaction for the Mississippi Public Service Commission ("MPSC") to make an informed decision supported by the record in this docket. My testimony is offered on behalf of the Mississippi Public Utilities Staff ("MPUS").

Q. Was your testimony prepared by you or by others under your direction?

A. I prepared much of my testimony and was assisted by three of my LAI colleagues. (i) Edward Tsikirayi, Executive Consultant, has expertise in bulk power system planning and operations, and was previously employed by the Independent System Operator - New England ("ISO-NE"). (ii) Dr. Boris Shapiro, Executive Consultant, has expertise in power systems, generators, competitive markets, and regulation, and was previously employed by the Massachusetts Department of Public Utilities. (iii) Alexander Mattfolk, Consultant, has provided analytical support and conducts economic input-output modeling. As the sponsoring witness on behalf of the MPUS, all research and analysis undertaken by the LAI project team was performed under my direction.

Q. Have you previously testified?

A. Yes. I have testified before the state regulatory commissions in Connecticut, Rhode Island, Vermont, and Virginia, and in judicial courts. I have also participated in technical panels at the Federal Energy Regulatory Commission ("FERC").

Q. Have you previously testified before the MPSC?

A. No.

II. SUMMARY OF CONCLUSIONS – THE TRANSACTION FAVORS SHAREHOLDERS AT THE EXPENSE OF RATEPAYERS

Q. Mr. Parker, do you believe the Transaction should be approved?

A. No. In my opinion, the proposed Transaction unreasonably favors shareholders at the expense of ratepayers. I estimate that Entergy shareholders will receive $2.5 billion in net benefits, principally through the receipt of ITC shares . At the same time, transmission revenue requirements for Entergy Mississippi ("EMI") retail customers and for wholesale customers combined will increase due to FERC allowing ITC to use a higher weighted average cost of capital ("WACC") to calculate its transmission rates.[1] Over the next five years, retail revenue requirements will increase by at least $49.5 million on a nominal basis, equivalent to $39.0 million on a net present value ("NPV"). Over thirty years, this increase will be no less than $348.2 million on a nominal basis or $126 million on an NPV basis. The increase in transmission revenue requirements and rates is certain, and is in contrast to the claimed ratepayer benefits that are uncertain, speculative, and have no company commitment behind them. Moreover, nothing in the Applicants' prefiled testimonies and data responses has convinced me that EMI needs to transfer its transmission system to ITC to achieve better performance. Thus Entergy shareholders would benefit at the expense of EMI and other Entergy Operating Company ("EOC") ratepayers.

Q. Please briefly summarize the proposed Transaction.

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[1] The higher WACC is due primarily to a higher return on equity ("ROE") and a 60% equity / 40% debt capital structure, both of which were granted by FERC.

A. The Applicants, *i.e.* EMI, ITC Holdings ("ITC"), and related companies, have proposed that EMI and the EOCs spin off their transmission assets into a new subsidiary, Mid South Transco, of Entergy Corporation ("Entergy") and merge that subsidiary into ITC, to be known as ITC Midsouth (collectively the "Transaction"). In return for divesting their transmission assets and merging them into ITC, Entergy shareholders will receive shares in ITC and be relieved of certain debt obligations.

Q. Please summarize your specific findings concerning the Transaction.

A. The Applicants claim that the Transaction will accomplish four objectives that have been extensively discussed throughout the Applicants' direct testimonies. All four objectives have weaknesses that raise significant doubt about the Transaction and should be considered carefully by the MPSC, as follows.

The Applicants claim that ITC's superior financial strength will support EMI's escalating transmission investment requirements and can withstand any financial strain due to the extended cost recovery period for transmission investments. ITC's financial strength is built upon a combination of a high ROE and a high percentage of equity in its capital structure (collectively ITC's "rate construct") approved by FERC. The Applicants understated the increase in EMI customer rates that is directly due to ITC's FERC-authorized rate construct. Rates will rise even further as ITC invests in the EMI transmission system over time, with those new investments costing ratepayers more than if the transmission system remained with EMI under MPSC jurisdiction. Moreover, the rise in ITC's transmission rates would be certain, in contrast to the claimed ratepayer benefits that are uncertain and speculative.

The Applicants' second claim is that ITC's "singular focus" will improve EMI's transmission performance and will facilitate capital investments and improvements. Having a singular focus on transmission is not necessary to achieve a high level of performance. There are many transmission owners who have achieved a high level of transmission performance without having independent corporate ownership. Also, a key document that ITC submitted that purports to support its claim of superior performance has questionable underlying data. EMI could improve its transmission performance through better attention and adequate funding.

The Applicants' third claim is that the Transaction will (i) provide for regional transmission planning in an open and transparent manner considering a broad range of needs and (ii) will enhance the expected Midcontinent Independent System Operator ("MISO") wholesale energy market benefits. However, EMI's transmission planning will improve once it joins MISO. MISO membership will impose planning and operating regulations on EMI that are designed to provide a regional perspective and enhance EMI's transmission practices. Through MISO, EMI will be able to pursue transmission projects to meet reliability, economic efficiency, and state policy objectives. EMI will also be able to take advantage of MISO's wholesale energy market benefits, *i.e.* the Day 2 Market. These MISO benefits will be available absent the Transaction. ITC's claims that the Transaction will enhance MISO wholesale energy market benefits are uncertain and speculative, and ITC has made no commitment to support its claims. In fact, ITC's estimated net production cost benefits for a hypothetical transmission portfolio are negative for EMI.

The Applicants' last claim is that ITC's independence (i) will allow it to focus on planning, constructing, operating, and maintaining a reliable and robust transmission system and (ii) will promote transparency and eliminate perceptions of bias. This claim has no solid foundation. .

Once EMI joins MISO and is subject to MISO's transparent transmission planning and system operating rules, Entergy will have less ability to use its ownership of transmission to favor its own generation over its competitors'. The Applicants articulate no specific anticompetitive behaviors that EMI could still engage in as a MISO member that would be precluded by ITC ownership and offer. Nor do Applicants commit to any quantitative value to ratepayers arising from the ostensible elimination of bias. Under these circumstances, it is premature to conclude that there will be benefits sufficient to justify the definite rate increases that the transaction will cause.

Q. Based on your analysis of the Transaction, what is your overall recommendation for the MPSC?

A. Based on my analysis, I recommend that the MPSC should not approve the Transaction as proposed by the Applicants. If the MPSC approves the Transaction, it should impose conditions to protect ratepayers by (i) establishing milestones to ensure adequate capital and maintenance investments and (ii) requiring specific, measurable, and enforceable performance metrics that must be achieved before transmission rates can be increased, as well as conditions recommended by Staff witness Hempling.

Q. Do you have additional recommendations for the MPSC?

A. Yes. First, if the Transaction is not approved, I recommend that the MPSC initiate a proceeding into EMI's past transmission investment, funding adequacy, operating, and maintenance practices to determine if EMI has fulfilled its statutory obligations in light of the past underfunding of its transmission business, its demonstrated poor performance, claims of bias, and the recent penalty imposed by FERC for transmission and other reliability violations.[2] This proceeding should also investigate the cost and time required to achieve a target level of transmission performance.

Second, if the Transaction is approved, the MPSC should impose reasonable and necessary conditions to assure that (i) the Transaction benefits are reasonably split between Entergy shareholders and EMI customers, (ii) EMI customers are protected so that any proposed transmission rate increase is predicated upon achieving specified transmission performance milestones, and (iii) the MPSC is assured of reasonable access to ITC information regarding the EMI transmission system.

Third, regardless of the outcome in this docket, I recommend that the MPSC devote the necessary personnel and financial resources to participate in the MISO regional stakeholder process and take full advantage of its opportunities to influence important decisions and fulfill its regulatory responsibilities.

These recommendations recognize that EMI and the other EOCs face pressing challenges regarding transmission planning, investment, and operations. While MISO membership has the potential to accomplish many of the objectives identified by the Applicants, I recognize that more needs to be done. Therefore, I encourage the MPSC to reach an informed decision on the complete set of broad issues raised by the Transaction in a manner that fairly aligns the interests of all parties and protects ratepayer interests over the long term.

[2] FERC Order dated March 28, 2013, approving Stipulation and Consent Agreement in Docket IN13-9-000 addressed violations regarding (i) Facilities Design, Connections, and Maintenance, (ii) Transmission Operations, (iii) Transmission Planning, (iv) Personnel matters, and (v) Critical Infrastructure Protection.

III. THE TRANSACTION WILL LEAD TO HIGHER EMI TRANSMISSION RATES

Q. What is the rate construct that ITC has proposed for the Transaction, and how does it compare to EMI's?

A. ITC's rate construct is comprised of two key components: an allowed ROE of 12.38% and (ii) a capital structure of 60% equity / 40% debt. EMI currently has an allowed ROE of 10.8% and a capital structure of roughly 50% equity / 50% debt. ITC Mississippi, the ITC operating company that would own and operate EMI's transmission assets, will utilize ITC's rate construct, which has a higher cost of equity and more high-cost equity in its capital structure compared to EMI.

A. ITC's Rate Construct Will Lead to Higher Revenue Requirements for EMI's Transmission Assets

Q. What is the WACC for (i) EMI given its current costs of capital and (ii) ITC given the rate construct it has proposed, and how would any difference affect transmission rates for EMI customers?

A. The pre-tax WACCs for EMI and ITC-Mississippi were presented by ITC witness Bready in Exhibit CMB-7 to his direct testimony for the years 2014 through 2018. The following table presents Mr. Bready's data and indicates that ITC Mississippi's retail revenue requirements would rise an average of 9.9 million per year during the first five years after the Transaction compared to EMI ownership. Over a 30 year period, EMI ratepayers will receive an additional retail revenue requirement of at least $126 million (NPV) which is discussed in further detail in part D of this Section.

Table 1: ITC Mississippi Revenue Requirement with Bready Costs of Debt

($ millions)

	2014	2015	2016	2017	2018
ITC Mississippi WACC	13.55%	13.59%	13.63%	13.65%	13.68%
EMI WACC	11.61%	11.70%	11.70%	11.73%	11.75%
Difference in WACC	1.94%	1.89%	1.93%	1.92%	1.93%
Average Rate Base	$505.8	$554.9	$611.8	$666.3	$715.8
Increased Total RR	$9.8	$10.5	$11.8	$12.8	$13.8
Retail % of RR	84%	84%	84%	84%	84%
Increased Retail Revenue Req't	$8.3	$8.8	$9.9	$10.8	$ 11.6

B. The Applicants' Cost of Debt Assumptions Are Inconsistent

Q. Were Mr. Bready's WACC and revenue requirement calculations reasonable?

A. While Mr. Bready's calculations appear to be correct, his underlying assumption regarding the cost of debt deserves attention. Mr. Bready calculated EMI's WACC using its average embedded cost of debt that reflects the cost of EMI debt issued over many years at various interest rates. However, Mr. Bready calculated ITC Mississippi's WACC assuming newly issued debt that reflects current market conditions.

Q. Please explain Mr. Bready's assumption for EMI's embedded cost of debt.

A. According to Entergy's 2012 Form 10-K, EMI had nine mortgage bonds outstanding as shown in the table below.

Table 2: EMI Mortgage Bonds as of 2012 Entergy 10-K Filing

Series	Issuance Date	Maturity Date	Face Value ($ millions)
6.00% Series	November 2002	November 2032	$75
5.15% Series	January 2003	February 2013	$100
4.95% Series	May 2003	June 2018	$95
6.25% Series	April 2004	April 2034	$100
6.64% Series	June 2009	July 2019	$150
6.20% Series	April 2010	April 2040	$80
6.00% Series	April 2011	May 2051	$150
3.25% Series	May 2011	June 2016	$125
3.10% Series	December 2012	July 2023	$250

EMI's costs of debt, *i.e.* interest rates, are generally consistent with the economic conditions at the time they were issued. The interest rates for EMI's outstanding bonds are also generally consistent with Mr. Bready's assumption of a 6.1% average embedded cost of EMI's existing debt as indicated on page 42 of his direct testimony. I ignored the 3.25% and 3.10% Series bonds for the purpose of this comparison because their unusually low interest rates are indicative of tax-exempt debt and are thus not relevant.

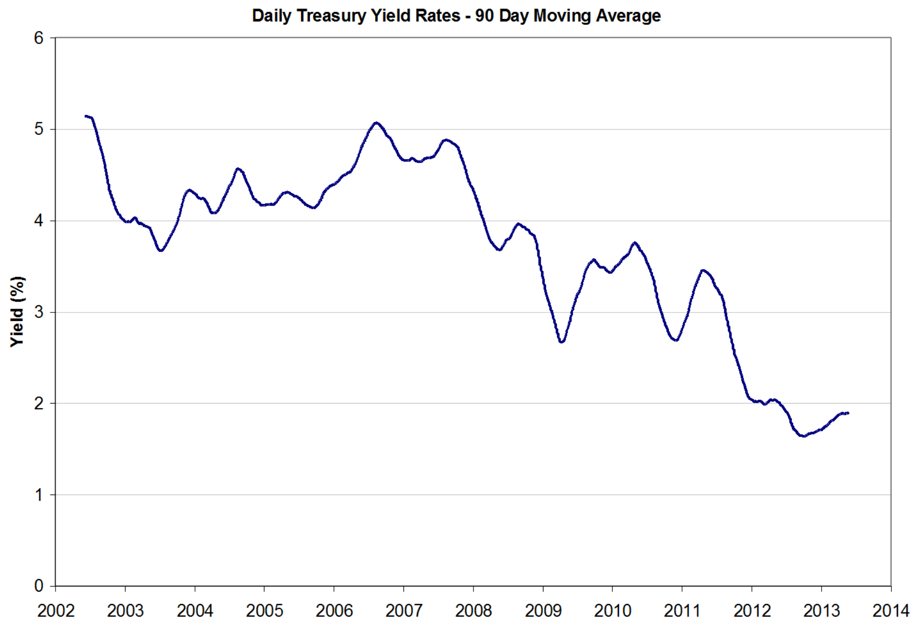
Q. Please explain Mr. Bready's assumption for ITC Mississippi's cost of newly issued debt.

A. Mr. Bready assumed that ITC Mississippi would be able to issue debt a 3.5%, as listed on page 42 of his direct testimony. Mr. Bready's assumption reflects two factors.

First, Mr. Bready's ITC Mississippi debt cost assumption reflects the current environment of low interest rates and low inflation expectations. Figure 1 below illustrates how Ten Year U.S. Treasury Bond interest rates have declined over the past five years.[3]

[3] Source: US Department of the Treasury, Daily Treasury Yield Curve Rates. http://www.treasury.gov/resource-center/data-chart-center/interest-rates/Pages/TextView.aspx?data=yield.

Figure 1: Ten Year U.S. Treasury Bond Yields



Second, Mr. Bready's ITC Mississippi debt cost assumption reflects ITC's better credit rating compared to EMI. On page 19, Mr. Bready presented senior secured debt ratings for the ITC operating companies and for EMI. The Standard & Poor's ("S&P") and Moody's ratings for the ITC operating companies were A and A1, respectively. The S&P and Moody's ratings for EMI were A- (one notch lower than the ITC operating companies) and Baa1 (three notches lower than the ITC operating companies), respectively.

Q. Did Mr. Bready err in utilizing EMI's average embedded cost of debt and ITC Mississippi's expected cost of newly issued debt?

A. Yes. While these debt costs are relevant in the context of the Transaction, any comparison between the two companies' interest rates must recognize the difference in market conditions between the past times that EMI issued debt and the future time that ITC Midsouth is expected to issue debt. EMI debt was issued at points in time when interest rates were higher, reflecting market conditions at that time. Hence, the interest rate on existing EMI debt average is 6.1% today, while ITC Mississippi will benefit from the current period of low interest rates when it issues new debt to finance new transmission investments.

Mr. Bready erred in his Exhibit CMB-7 in which he assumed that EMI's debt cost would continue to reflect historical interest rate conditions while ITC Mississippi's debt cost would stay low. By not recognizing that new EMI debt would also benefit from low interest rates, Mr. Bready has compared apples-to-oranges, as shown in Table 3 below. If ITC Mississippi will benefit from a low interest rate environment, then so will EMI. If current trends continue EMI's average interest rate should be coming down over time, not increasing as Mr. Bready has assumed.

Table 3: Bready Exhibit CMB-7 Debt Costs

	2014	2015	2016	2017	2018
EMI	6.11%	6.19%	6.27%	6.32%	6.37%
ITC Mississippi	3.81%	3.90%	3.99%	4.06%	4.12%
Difference	2.30%	2.29%	2.26%	2.26%	2.25%

Q. What would be the current cost of debt for ITC Mississippi, and what would be the impact of utilizing current costs of debt for it and EMI?

A. On page 7 of 18 in his Exhibit CMB-5, Mr. Bready provided Estimated New Issue Credit Spreads for the ITC operating companies and for EMI. While those data were as of February 28, 2012, I do not believe that market conditions have changed appreciably since then. Mr. Bready's data indicate a 60 basis point spread between ITC Mississippi and EMI, which appears reasonable.

In his Exhibit CMB-7 that presented his revenue requirements calculations, Mr. Bready utilized a 3.81% cost of debt for ITC Mississippi in 2014. Applying Mr. Bready's 60 basis point differential to his estimate of a 3.81% ITC Mississippi interest rate results in an EMI interest rate of 4.41% for new debt issued in 2014. Utilizing this lower cost of EMI debt in Mr. Bready's CMB-7 spreadsheet (i) reduces EMI's pre-tax WACC from 11.61% to 10.76% for 2014 and by similar amounts through 2018 and (ii) increases the differential between ITC Mississippi's WACC and EMI's WACC. I applied the lower debt costs to new transmission investments and applied the historical average debt cost to the existing transmission rate base. As a consequence, the 2014-2018 revenue requirement differential increases from an average of $9.9 million per year to $11 million per year as illustrated in the table below.

Table 4: ITC Mississippi Revenue Requirement with Corrected Costs of Debt
($ millions)

	2014	2015	2016	2017	2018
ITC Mississippi Debt	3.81%	3.90%	3.99%	4.06%	4.12%
Debt Spread	0.60%	0.60%	0.60%	0.60%	0.60%
Corrected EMI Debt for New Investments	4.41%	4.50%	4.59%	4.66%	4.72%
Corrected Increased Revenue Requirement	$8.5	$9.5	$11.0	$12.4	$13.6

Q. How much more would EMI ratepayers pay for transmission service using Mr. Bready's assumption that 84.4% of EMI's revenue requirements are borne by EMI ratepayers?

A. Based on this apples-to-apples analysis that considers the current estimated cost of debt for ITC Mississippi and EMI, EMI ratepayers would pay an average of $11 million per year more due to ITC's rate construct for the first five years after the Transaction, and more in succeeding years as the transmission rate base grows.

C. EMI Transmission Rates Will Increase

Q. What effect did the Applicants claim the Transaction would have on EMI transmission rates?

A. In general, the ITC witnesses described the rate effects on retail customers as "modest" and claimed that such rate effects will be offset by benefits that have yet to be quantified. On page 31, lines 2-7 of his direct testimony, Entergy witness Lewis estimated the impact of ITC's rate construct on a typical EMI residential customer:

> The projected customer bill effect in 2014 was calculated using the average 2011 monthly bill for a typical residential customer using 1,000 kWh/month. For a typical monthly residential bill, the change in transmission revenue requirement will result in an estimated increase of approximately $0.66 per month in a residential customer's bill or approximately 0.7%, excluding the timing and other effects I discuss below.

In Figure 9 on page 32 of his direct testimony, Mr. Lewis also estimated the impact of ITC's rate construct on a larger retail, *e.g.* commercial, customer taking GS service at $3.86/month, approximately a 0.7% increase as well. As with the estimated impact on a residential customer, this increase excludes the impacts of changing to a forward looking test year and elimination of MSS-2.

Q. Did Mr. Lewis's estimate of a $0.66 per month increase in a typical residential customer's bill reflect higher rates after 2014?

A. No. Mr. Lewis's calculation only applied to 2014. It is clear that transmission rates will increase over time as investments are made and transmission rate base grows. Based on workpaper attachments to Entergy's response to MPUS 1-77, I calculated that the increase in a typical residential bill will grow to [Begin HSPM] [redacted]. [End HSPM] Moreover, transmission rates for EMI customers will continue to grow beyond the Applicants' five year study period.

Q. What are the expected costs to retail ratepayers due to the Transaction over the five year period 2014-2018, according to the Applicants?

A. Based on Exhibit CMB-7, I noted that total retail revenue requirement increases due to the Transaction will be $49.5 million over the next five years on a nominal basis, equivalent to $39.0 million on an NPV basis using ITC's 8% discount rate.

D. Higher Transmission Rates Due to ITC's Rate Construct Will Grow Over Time

Q. What are the expected costs to retail ratepayers due to the Transaction after the five year period 2014-2018?

A. The increase in EMI transmission rates in the Joint Application is misleadingly low because Mr. Bready selected a five-year study horizon for his analysis. Over a longer term, the additional investment in transmission rate base has a significant effect on EMI's revenue requirements and customer transmission rates. I was able to develop a minimum estimate using ITC's worksheet provided by Mr. Bready as a native Excel version of CMB-7 along with certain conservative assumptions.

Q. What are the results of your analysis?

A. Extending the EMI retail revenue requirements calculation from five years to thirty years increases the amount to be recovered from retail customers from a nominal $49.5 million as presented by Mr. Bready in his Exhibit CMB-7 to at least $348.2 million, equivalent to $126 million on an NPV basis, as shown in

Table 5 below. I convey the revenue requirement increase in terms of "at least" because assuming 0% rate base growth over 25 years is unrealistic. However, the actual growth in rate base over the twenty-five year period is unknown. For this reason, I provide examples of possible retail revenue requirements assuming 5% annual rate base growth over twenty-five years and 10% rate base growth over twenty-five years. I offer 5% and 10% scenarios solely as demonstrative examples of how annual rate base growth will affect the retail revenue requirement.

Table 5: Higher Retail Revenue Requirements Due to ITC Rate Construct
($ millions)

Rate Base Growth (2019-2043)	Five Years (2014-2018)		Thirty Years (2014-2043)	
	Nominal	NPV	Nominal	NPV
0%	$49.5	$39.0	$348.2	$126.0
5%	$54.9	$43.0	$813.2	$222.6
10%	$54.9	$43.0	$1,706.0	$371.9

Q. What assumptions did you use to calculate the higher EMI retail rates?

A. I made two assumptions, each of which is consistent with Mr. Bready's assumptions in his Exhibit CMB-7. First, I assumed that ITC-Mississippi's transmission rate base will continue to increase by 10% annually for the first five years per Mr. Bready's Exhibit CMB-7 but then considered a range of growth rates for the following twenty-five years, from 0% to 10%. Third, I used ITC's discount rate of 8% to calculate NPV values.

In addition, I assumed (i) EMI's historical average 6.1% debt rate would apply to EMI's existing transmission rate base (that declines by 2.3% per year) and (ii) EMI's lower debt rates in the future would apply to all new transmission investments in the 5% and 10% growth scenarios (for the 0% case I maintained Mr. Bready's debt rate assumptions). Lastly, I corrected Mr. Bready's debt assumption so that EMI would have debt rates consistent with ITC Mississippi's, *i.e.* a 60 basis point differential as Mr. Bready indicated in his Exhibit CMB-5, for those new transmission investments.

Q. Should the MPSC rely on your thirty-year estimates rather than on Mr. Bready's five-year estimate?

A. Given the critical importance of this matter, I also believe that the MPSC should not be swayed by short-term considerations at the expense of the long-term welfare of EMI ratepayers. In my opinion, a long-term perspective is the proper perspective for evaluating this transaction.

E. Rate Mitigation Cannot Balance the Competing Interests of Shareholders and Ratepayers

Q. How could the Applicants address concerns regarding the expected increase in transmission rates due to the Transaction?

A. I note that the Transaction will cause transmission rates to increase immediately following the Transaction, *i.e.* without any change in transmission assets, operations, or performance. One way the Applicants could address the expected rate increase would be through rate mitigation by which the new, higher rates would be gradually implemented. Assuming the Applicants offer in MS a "mitigation" comparable to what they presented in Arkansas and Louisiana, the amount would be around $60M. The Applicants have proposed in other states a rate mitigation scheme which in addition to covering the rate increases associated with the higher FERC ROE and capital structure will also mitigate rate increases due to the elimination of the MSS-2 schedule, which would occur regardless of the transaction. There would be no mitigation after five years.

I considered this mitigation to be worth roughly $53.3 million to retail customers on a nominal basis, or $44.7 million on an NPV basis. I made assumptions about the timing of this rate mitigation based on Mr. Lewis's rate workpapers with regards to the MSS-2 charge along with some assumptions based on the WACC related increases found in CMB-7. The effect of this mitigation is illustrated in Table 6 below.

Table 6: Higher Revenue Requirements Due to ITC Rate Construct Including Hypothetical Rate Mitigation ($ millions)

Rate Base Growth (2019-2043)	Five Years (2014-2018)		Thirty Years (2014-2043)	
	Nominal	NPV	Nominal	NPV
0%	$(4.1)	$(5.6)	$294.8	$81.3
5%	$1.9	$(1.9)	$759.9	$157.9
10%	$1.9	$(1.9)	$1,652.7	$327.3

Q. What is the effect of this "mitigation" on the original proposal?

A. Not much, if one views it in the context of the full proposal. . It reduces the 30-year minimum cost ($126 million) to $81 million—the total new cost retail ratepayers bear in return for the Commission losing its jurisdiction and receiving no commitments for improvements.

Q. Does the hypothetical rate mitigation compensate ratepayers for the uncertain benefits that the Applicants claim will materialize over time?

A. No. The increase in transmission rates, even mitigated, is certain, while ratepayer benefits are speculative and uncertain under the proposed Transaction.

IV. THE TRANSACTION WILL GIVE ENTERGY SHAREHOLDERS A MULTI-BILLION DOLLAR NET BENEFIT AT RATEPAYERS' EXPENSE

Q. Will Entergy shareholders receive a multi-billion dollar benefit from this Transaction?

A. Yes. Under the Reverse Morris Trust structure of the proposed Transaction, Entergy will spin off its transmission assets and merge them into ITC as a new ITC subsidiary, ITC Midsouth, which will include ITC Mississippi. As a result, Entergy shareholders will give up the transmission-related value of their existing Entergy shares in return for receiving ITC shares. Those ITC shares will reflect a higher market valuation of those transmission assets because of (i) ITC's rate construct of a high allowed ROE and a high percentage of equity in ITC Midsouth's capital structure, coupled with (ii) ITC's leveraging by funding of operating company equity with a blend of parent company debt and equity. The benefits of ITC's financial structure flow to its shareholders.[4] Thus the Entergy shareholders' net benefit I estimated is comprised of three key components:

1. Receipt of ITC shares adjusted for special distribution
2. Entergy shares lose transmission portion of their market value

A. Entergy Shareholders Will Receive ITC Shares Worth Just Over $4 Billion

Q. Has ITC estimated the value of ITC shares that will be issued to Entergy shareholders following the transaction?

A. Yes. ITC filed Amendment No. 2 to the SEC Form S-4 on January 28, 2013 to register additional shares of its common stock that will be issued in connection with the merger of ITC

[4] Entergy also leverages the equity in its operating companies with parent company debt and equity.

Midsouth. In this filing, ITC estimated that 52,786,090 shares would be issued to Entergy shareholders at a value of $64.50 per share. This "fair value" share price was based on the ITC closing price of $78.09 as of January 18, 2013 less $13.59 per share due to the special dividend of $700 million that ITC intends to issue as part of the Transaction. According to these assumptions, Entergy shareholders will receive $3.4 billion worth of ITC shares.

Q. Have you updated the estimated value of ITC shares that Entergy shareholders will receive?

A. Yes. ITC's share price closed at $90.94 on May 1, 2013. I then (i) duplicated ITC's adjustment to reflect the special dividend that ITC shareholders will receive and (ii) multiplied the adjusted share price of $77.35 by the number of shares expected to be issued to Entergy shareholders to arrive a total value of $4.08 billion.

Table 7: ITC Estimate of ITC Share Price for Entergy Shareholders

	January 18, 2013 ITC Amend. No. 2	May 1, 2013 Update
ITC Share Price	$ 78.09	$ 90.94
less Special Dividend	$(13.59)	$(13.59)
Adjusted Share Price	$ 64.50	$ 77.35
Shares to be Issued	52,786,090	52,786,090
Value Received	$3.40 billion	$4.08 billion

B. Entergy Shareholders Will Give Up Approximately $1.6 Billion of Share Value

Q. How will the sale of Entergy's transmission assets affect Entergy shareholders?

A. Entergy shareholders will give up the transmission portion of their existing share value (whose price reflects a low valuation of Entergy's transmission assets) in return for ITC shares (whose price will reflect a higher valuation of those identical transmission assets).

Q. Did any Entergy or ITC witness estimate the loss in Entergy share value due to the Transaction?

A. No, to the best of my knowledge, they did not.

Q. Can you estimate the loss in Entergy share value based on its transmission percentage of total assets?

A. Yes. LAI examined three sets of data to estimate the transmission assets as a percentage of Entergy's total assets. The results of these three approaches, which average 12.5%, are summarized in

Table 8 below.

First, ITC's Amendment No. 2 provided an unaudited estimate of $4.09 billion for all of Entergy's transmission assets (after minor adjustments) as of September 30, 2012, including cash and other current assets, regulatory assets, etc. Based on Entergy's consolidated asset value of $42.02 billion as of the same date from its Q3 2012 Form 10-Q, the transmission assets comprise 9.7% of Entergy's total assets.

Second, if the same comparison is performed on the "hard assets" of Entergy's transmission property, plant and equipment ("PP&E") listed in ITC's Amendment No. 2 of $3.83 billion, then the transmission assets comprise 14.5% of Entergy's total PP&E value of $26.43 billion.

Third, Entergy's 2012 Form 10-K divides its PP&E assets into business segments. Transmission assets of $3.65 billion comprise 13.4% of its total PP&E value as of year-end 2012. This value is generally consistent with the 14.5% PP&E value per ITC's Amendment No. 2.

Table 8: Entergy Transmission Percentage of Total Assets ($ billions)

	Sept. 30, 2012 All Assets	Sept. 30, 2012 PP&E	Dec. 31, 2012 PP&E	Average Value
Entergy Transmission Assets	$ 4.09	$ 3.83	$ 3.65	
Entergy Total Assets	$42.02	$26.43	$27.30	
Percentage	9.7%	14.5%	13.4%	12.5%

Q. How will the sale of Entergy's transmission assets affect its share price?

A. Assuming that equity investors value transmission assets equally with other corporate assets, I estimate Entergy shares will decline approximately 12.5% when the EOC transmission assets are spun off. This key assumption of equal valuation is reasonable given that rate-based transmission assets are entitled to the same allowed ROE as other state-jurisdictional rate-based generation and distribution assets. I have ignored the fact that transmission assets have a longer depreciation period and hence generate lower revenues in the short term for the purpose of this estimate. The equal ROE treatment of transmission assets will continue when Entergy joins MISO as transmission service will presumably be bundled with other services for rate purposes.

As of January 18, 2013 (the date of ITC's Amendment No 2), Entergy shares closed at $63.87 per share. If the Transaction had occurred then, the decline in share price would have been $7.98, a shareholder loss of $1.42 billion. Using more recent data as of May 1, 2013, consistent with the ITC share price calculations above, Entergy shares closed at $71.39 per share. Using this more recent data, the decline in Entergy share prices would be $8.92 for a total shareholder loss of $1.58 billion. I note that my estimate is highly dependent upon equity investor reaction to the Transaction.

Table 9: Estimated Decline in Entergy Share Price
(as of May 1, 2013)

Entergy Share Price	$71.39
less Transmission Percentage	12.5%
Loss in Share Value	$8.92
Shares Outstanding (12/31/2013)	177,324,813
Loss in Shareholder Value	$1.58 billion

C. Entergy Shareholders Will Receive a Net Benefit of $2.5 Billion

Q. If Entergy share prices will decline following the transaction, why would shareholders seek the Transaction?

A. This estimated $1.58 billion decline will be more than offset by the $4.08 billion estimated market value of ITC shares they will receive, a net benefit of $2.5 billion.[5] The market value of the ITC shares, including an adjustment to reflect the $740 million ITC will issue to effectuate the Transaction, would be $77.35 based on May 1, 2013 market prices, as explained above. After consideration of the number of Entergy shares outstanding as of year-end 2012 (undiluted) and the number of new ITC shares to be issued, I estimate a net benefit of $2.5 billion for existing Entergy shareholders.

[5] This benefit calculation does not consider that ITC will assume $1.775 billion of Entergy debt which could potentially produce further benefits.

Table 10: Estimated Entergy Shareholder Net Benefit
(as of May 1, 2013)

Adjusted ITC Share Price	$77.35
Shares to be Issued	52,786,090
1. Value of ITC Shares Issued	$4.083 billion
Entergy Share Price	$71.39
Decline in Value	12.5%
Loss in Share Value	$8.92
Entergy Shares Outstanding	177,324,813
2. Decrease in Share Value	$(1.582 billion)
Net Benefit to Shareholders	$2.5 billion

Q. Is there some uncertainty in your estimate of Entergy shareholder net benefit?

A. Yes. It is virtually impossible to predict how investors, and the stock market in general, will view the divestiture of Entergy's transmission business and subsequent decline in Entergy share value. The market price of ITC's shares ultimately granted to Entergy shareholders will also affect the net benefit estimate.

Q. Have the Applicants provided an estimate of the net benefits for Entergy shareholders?

A. No, they have not in this docket. I note that ITC's Prospectus contains a calculation of the consideration to be transferred to Entergy, but it does not address the loss in Entergy share value.

Q. Does the Prospectus provide a separate estimate of the consideration that ITC shareholders will provide to Entergy relative to the net asset value of the transmission assets?

A. Yes. ITC estimated that it will provide $3.56 billion of ITC shares (priced as of September 30, 2012) and assume $2.93 billion of liabilities (including Entergy's $1.775 billion debt issuance), in return for EOC assets (primarily transmission assets that have a net book value of $3.83 billion). Thus ITC will book the difference of $2.40 billion as "goodwill" on its balance sheet.

Q. Can you update the consideration that will be provided to Entergy, and the amount of goodwill over and above the net asset value of the transmission assets?

A. Yes. As shown in Table 11 below, I updated ITC's estimate using the ITC share price as of May 1, 2013 consistent with my earlier calculations. I estimate that ITC will be paying $2.87 billion more than the net asset value of the EOC's transmission assets.

Table 11: ITC's and Updated Estimate of Goodwill
(per ITC Prospectus; $ billions)

ITC Share Price Date	2/22/2013	5/1/2013
ITC Share Value	$ 3.56	$ 4.03
Total Liabilities	$ 2.93	$ 2.93
- Total Assets (excl. Goodwill)	$(4.09)	$(4.09)
Goodwill	$ 2.40	$ 2.87

Q. What percentage of the premium over the EOC's net asset value can be attributed to EMI?

A. According to Entergy's 2012 Form 10-K, EMI's net transmission assets of $581 million represented about 16% of the EOC's total. Using this allocation factor, ITC will be providing consideration worth approximately $460.8 million more than EMI's net asset value for its transmission assets.

V. ITC'S ESTIMATE OF TRANSACTION BENEFITS IS UNRELIABLE, OVERALL NET BENEFITS ARE BARELY POSITIVE, AND ARE NEGATIVE FOR EMI CUSTOMERS

Q. Has ITC attempted to quantify the benefits of its independent transmission planning perspective?

A. ITC witness Pfeifenberger, a Principal of the Brattle Group, offered expert testimony on "the potential benefits that ITC's independent transmission planning perspective offers to Mississippi in support of…" the Transaction. According to page 5, lines 16-17 of his direct testimony, he "describe[d] the process of benefit identification and calculation as applied to a hypothetical portfolio of potential 'strategic' transmission projects." Mr. Pfeifenberger estimated the benefits from a "hypothetical portfolio of potential strategic transmission projects" utilizing a chronological dispatch simulation model. As explained next, his analysis offers no reliable basis for approving this transaction.

A. The Strategic Transmission Projects are Hypothetical and Could Be Built by EMI

Q. Has ITC actually proposed to build any of the transmission projects in this portfolio?

A. No. As Mr. Pfeifenberger explained (at p.21):

> The selected illustrative strategic projects, however, represent only examples of the types of projects that ITC would be interested in pursuing if supported by further studies, approved in the MISO MTEP, and supported by stakeholders. To summarize, the initial effort undertaken for the purpose of my testimony is simply an illustration of the type of independent planning process that ITC would undertake and, possibly, the first step in a more comprehensive transmission planning effort going forward with MISO.

Mr. Pfeifenberger's strategic transmission projects are hypothetical and the resulting benefits are therefore speculative. However, it is still worth reviewing his analysis in light of his specific results for EMI customers.

Q. Did Mr. Pfeifenberger's portfolio of strategic projects include any in Mississippi?

A. Yes. According to page 19, line 11 of his direct testimony, his portfolio of six projects includes "…a new 500 kV project in northwestern Mississippi…"

Q. Might some of these transmission projects have been identified through the MISO transmission planning process and been constructed by EMI?

A. He gives no reason why these same projects could not have been identified by EMI itself or through the MISO transmission planning process or why ITC has some unique ability to do so that EMI does not have. In fact, in footnote 5 on page 19 of his direct testimony, Mr. Pfeifenberger noted that two of his strategic projects, known as the "Congestion Relief" projects, "…likely… would also be identified through MISO's planning process."

B. Mr. Pfeifenberger's Analysis is Unreliable

Q. Does Mr. Pfeifenberger's analysis consider the impact of MISO's transmission planning process separate from the Transaction?

A. No. Mr. Pfeifenberger calculated the benefits of his portfolio of strategic transmission projects relative to the projects that EMI and the other EOCs are currently planning, *i.e.* the base case. Mr. Pfeifenberger did not attempt to identify the projects that would be constructed by EMI and the other EOCs absent the Transaction through MISO's planning process. Thus Mr.

Pfeifenberger's analysis does not provide a useful estimate of any incremental power market benefits due to the Transaction itself, separate from the EOCs joining MISO.

Q. What does Mr. Pfeifenberger calculate as the costs for his strategic portfolio?

A. Figure 1 on page 29 of his direct testimony lists the costs and benefits for Entergy and "neighboring regions" as reproduced in

Figure 2 below. Each cost and benefit represents a 40-year NPV in 2017 dollars. The estimated net project cost, determined by the net revenue requirement of the strategic projects, is $2.105 billion.

Q. Is there some way to verify the reasonableness of Mr. Pfeifenberger's cost estimate for building, operating, and maintaining the strategic projects on lines a-c of

Figure 2**?**

A. No. Although Mr. Pfeifenberger provided detailed revenue requirements calculations, he did not provide a detailed explanation for his capital cost estimates which form the basis of these calculations.

Figure 2: Pfeifenberger Costs and Benefits of Strategic Transmission Projects

Summary of the Selected Illustrative Strategic Projects' Net Revenue Requirement and Total Benefits

		40-Year Net Present Value (2017 $million)
Net Project Cost:		
Revenue Requirement of Strategic Projects	[a]	$2,462
Reduced Revenue Requirement of Deferred Reliability Projects	[b]	($357)
Net Revenue Requirement of Strategic Projects	[c]	**$2,105**
Societal Benefits:		
System-Wide Production Cost Savings	[d]	$1,406
Resource Adequacy Benefit from Deferred Generation Investments	[e]	$717
Avoided Capacity Needs due to Reduced Peak Losses in Entergy Region	[f]	$51
Reduced CO2 Emissions in Entergy Region	[g]	Not Monetized (↓ 1 million tons/yr)
Storm Hardening	[h]	Not Quantified
Options for Increasing Load-Serving Capability in Industrial Corridor	[i]	Not Quantified
Economic Development from New SPP Intertie Generation, Transmission Construction, and Increased Load-Serving Capability	[j]	Not Quantified
Improved Reliability and System Flexibility	[k]	Not Quantified
Additional Improvements in Market Access and Competitive Choices	[l]	Not Quantified
Total Monetized Societal Benefits	[m]	**$2,174**

Q. What does Mr. Pfeifenberger calculate as the benefits for his strategic portfolio?

A. Mr. Pfeifenberger provided estimated values for three categories of benefits: (i) production cost savings, (ii) deferred generation investments, and (iii) avoided capacity needs, as shown on lines d-f of

Figure 2. The total estimated benefit was $2.174 billion.

Q. Do generation production cost savings translate directly into ratepayer savings?

A. Not necessarily. Lower production cost from utility-owned generation that receives cost-of-service treatment can translate into savings for that utility's ratepayers. Any margin between the locational marginal price and the generation production costs could be returned to that utility's ratepayers, depending on the relevant jurisdiction's rate treatment. However, lower production costs from merchant generation do not necessarily imply ratepayer savings because those margins would be kept by the generator under the MISO competitive energy market rules. Whether the merchant generator chose to lower its price due to the lower production cost would depend on the extent of competition in the generator's market.

C. Mr. Pfeifenberger's Overall Estimated Benefits Barely Outweigh Costs

Q. Do you consider Mr. Pfeifenberger's portfolio of strategic projects to be supportive of the Transaction?

A. No. As calculated from

Figure 2, Mr. Pfeifenberger's estimated NPV benefit is $69 million, equivalent to 3.2% of the net revenue requirement of $2.105 billion. An NPV benefit of 3.2% is very modest, especially considering the extensive screening process that Mr. Pfeifenberger described. I recognize that some transmission projects are required for reliability and must be constructed regardless of net benefit, but Mr. Pfeifenberger's cost-benefit analysis provides virtually no support for the Transaction, especially since he gives no reason why EMI could not produce the same benefits without the transaction.

Q. How important are the missing categories of benefits?

A. Mr. Pfeifenberger's calculations do not include several potential benefits, as seen in lines g-l in

Figure 2, because he did not quantify them. Many of these benefits are admittedly difficult to quantify, *e.g.* economic development, system flexibility, and market access. I do not know, assuming there is a reasonable way to estimate them, if these benefits would result in significant changes to his overall results.

Q. Is the net NPV benefit significant enough to justify the cost and risks associated with this portfolio of strategic investments?

A. It is unclear how significant the missing benefits would be, but based on the quantified figures it appears that ratepayers would take on significant up-front costs and risks in order to obtain modest net benefits in the long run.

Q. Does Mr. Pfeifenberger describe how the costs and benefits associated with his calculation accrue over time?

A. Mr. Pfeiffenberger's direct testimony provides individual line item results as shown in his table and reproduced as

Figure 2. However, the workpapers for Mr. Pfeifenberger's calculations, provided as attachments to data request response MPUS-ITC 1-10, present the costs and benefits on an annual basis. By summing costs and benefits for each year and calculating an NPV for each year's end, I could determine when Entergy and the neighboring regions would break even using Mr. Pfeifenberger's own data. These calculations indicate that the NPV of the hypothetical strategic transmission portfolio does not become positive until 2044. Thus ratepayers across Mr. Pfeifenberger's entire study area would have to wait approximately 27 years before they realize a net benefit from the transmission portfolio.

Q. Does Mr. Pfeifenberger's study make any important assumptions that might significantly affect his analysis?

A. Yes. In order to calculate net revenue requirements for the strategic projects, Mr. Pfeifenberger subtracted the revenue requirement of deferred reliability projects from the revenue requirements of the strategic portfolio. In doing so, Mr. Pfeifenberger made several speculative assumptions.

[Begin confidential discussion] [redacted]

[redacted]

[redacted]

[redacted] [End confidential discussion] In short, there is significant uncertainty associated with Mr. Pfeifenberger's assumptions that may significantly affect his results.

D. EMI Customer Costs Will Outweigh Benefits

Q. How does the hypothetical portfolio affect customers in Entergy Mississippi?

A. On page 8, lines 15-16 of his direct testimony, Mr. Pfeifenberger admits "This set of illustrative strategic projects, selected solely from a regional perspective, <u>does not happen to offer significant benefits to EMI's customers</u>." (Underlining added for emphasis.)

Q. Is Mr. Pfeifenberger's wording regarding the impact on EMI's customers accurate?

A. No, Mr. Pfeifenberger has mischaracterized his results for EMI customers. According to his workpapers, it appears that the net impact on EMI's customers would almost certainly be negative, *i.e.* the costs would outweigh the benefits, as I explain below.

Q. Is it possible that the reason for Mr. Pfeifenberger's poor results for EMI customers was because he selected a poor set of strategic transmission projects?

A. Mr. Pfeifenberger screened his projects very carefully; I doubt he selected a set of projects that provided results contrary to the Applicants' claims. Mr. Pfeifenberger described how he worked with ITC and other consultants to identify an initial set of strategic transmission projects that would provide a range of benefits to the EOCs. According to page 18, lines 9-10 of his direct testimony, "After developing an initial list of strategic project ideas using an iterative process, the list was narrowed down to a few most promising projects to be investigated…When some of the initially-selected projects did not appear to provide the anticipated benefits, the portfolio was revised by improving the design of some of the projects and by eliminating or adding project ideas." Mr. Pfeifenberger went on to describe how "[t]he effort iterated through several cycles before settling on a smaller set of illustrative projects…" Therefore one could reasonably expect that Mr. Pfeifenberger screened out the worst and selected the best transmission projects for his analysis.

Q. Did Mr. Pfeifenberger calculate cost allocation of transmission revenue requirements in his approach?

A. No. Mr. Pfeifenberger explained his reasoning on page 22, lines 5-11:

> The cost allocation of any actual projects (not necessarily these illustrative projects) proposed by ITC would be subject to MISO's cost allocation policies, which generally follow the principle that costs should be allocated roughly commensurate with benefits received. This also means that it would be appropriate for other regions to share in the cost of some projects (e.g., under the interregional cost allocation provisions of FERC Order No. 1000) when a meaningful portion of the benefits extend to regions outside the MISO footprint.

Q. What costs associated with revenue requirements of the strategic portfolio may be allocated to EMI customers?

A. Since Mr. Pfeifenberger's strategic transmission projects would be built in the Entergy footprint, and one of his 500 kV projects would be built in EMI's service territory, some of the construction costs are likely to be borne by EMI.

Q. Did Mr. Pfeifenberger allocate costs and benefits among the EOCs?

A. Not all of them. Mr. Pfeifenberger calculated many specific costs and benefits for Entergy customers in his workpapers but only allocated reduced production costs among the individual EOCs because of allocation uncertainties. Mr. Pfeifenberger did not allocate any of the costs, including the revenue requirements for constructing the hypothetical strategic transmission portfolio, to the Entergy region, let alone to the individual the EOCs. Mr. Pfeifenberger allocated the benefits between the Entergy region and the surrounding markets in his study. Except for reduced production costs, he did not allocate these benefits among the EOCs. Without allocating these costs and benefits among the EOCs, it is difficult to predict how EMI customers would be affected by the hypothetical strategic transmission projects.

Q. Did Mr. Pfeifenberger's workpapers indicate a potential net cost for EMI customers?

A. Yes. Mr. Pfeifenberger estimated that generation production costs for EMI would increase by an average of [Begin HSPM discussion] [redacted] [End HSPM discussion] This result contrasts with the study area as a whole for which production costs would be lower, accounting for two-thirds of the benefits in his analysis. Since there are no other quantified benefits for EMI customers that could offset the cost of higher production costs, or some other portion of the costs (*i.e.* revenue requirements for the hypothetical strategic transmission projects that, are likely to be allocated to EMI customers) it is virtually certain that costs for EMI customers" will outweigh benefits.

Q. Does Mr. Pfeifenberger's inability to allocate costs and benefits among the EOCs limit the usefulness of his analysis and his results?

A. Yes. His methodology has weaknesses and utilizes uncertain assumptions. The claimed Transaction benefits are thus speculative and uncertain.

Q. As currently considered, do the benefits of the hypothetical portfolio of strategic projects outweigh the costs of the Transaction?

A. No. Given the modest margin of benefits over costs, Mr. Pfeifenberger's results do not support the Transaction in any meaningful way. Mr. Pfeifenberger emphasized the illustrative nature of his portfolio, noting that the hypothetical strategic transmission projects may not be built and that none have actually been proposed by ITC.

Q. Please explain how the risk of not achieving the benefits associated with ITC's performance has been shifted to EMI ratepayers in the proposed transaction.

A. Under the proposed Transaction, ITC shareholders will be entitled to the FERC-approved rate construct and resulting revenues regardless of actual performance. Hence, ITC shareholders bear minimum risk associated with not achieving the benefits under the current FERC rate construct, while ratepayers bear the entire risk that the claimed benefits will never materialize, or appear later and lower than hoped for. In fact, desirable results in terms of improved reliability, congestion relief, line loss reduction, and access to renewable generation may never be achieved, but ITC shareholders will enjoy higher revenues due to the ITC rate construct. Without tangible and measurable milestones, performance standards, and other requirements for ITC Midsouth, this transaction raises rates without compensating benefits.

Q. Is the proposed allocation of risk between shareholders' and ratepayers' risks consistent with the public interest?

A. No, this allocation of risk is inappropriate because it is inconsistent with traditional regulatory principles – quality service at just and reasonable rates. The appropriate way to shift some risk onto ITC shareholders, at a minimum, would be to restructure the Transaction so that any rate increase would be predicated on achieving performance and construction milestones whose value justifies the rate increase. Under this paradigm, any increased transmission costs would be offset by tangible and proven ratepayer benefits.

Q. Are there other parties that have commented on the costs and benefits for ratepayers?

A. Yes. In its Issuer Comment of December 12, 2011, Moody's stated "…FERC's rate-making leads to higher costs for ratepayers, while the benefits to them are not immediately apparent."

VI. THE TRANSACTION'S FINANCIAL RATIONALE IS EXAGGERATED, MISLEADING, AND MAY BE DUE TO INSUFFICIENT PAST FUNDING

Q. What financial rationale has EMI and ITC provided to support the Transaction?

A. According to the Joint Application, "…the ITC Transaction offers the financial strength of ITC and maintains that of the EMI to support escalating capital expenditure requirements. The ITC Transaction results in a smaller balance sheet for EMI by transferring the capital requirements for transmission to ITC…" This financial rationale is one of the four objectives identified in the Joint Application.

Q. What is EMI's specific financial rationale for the Transaction?

A. EMI has identified two specific financial concerns to support divesting its transmission assets. First, EMI has claimed to be facing a <u>significant funding requirement</u> over the next few years to replace old equipment, install new equipment, and expand the system to meet demand growth.

Second, EMI has claimed that transmission investments are a "financial strain" due to the long depreciation period that stretches out EMI's recovery of invested capital. ITC argues that it is financially stronger than EMI and thus better able to withstand the financial concerns claimed by EMI.[6]

A. EMI's First Claim that It Will Have Difficulty Funding Transmission Investments May Be Due to Entergy's Past Underfunding of EMI

Q. What are EMI's obligations for funding its transmission business?

A. FERC is authorized to enforce mandatory reliability standards established by the North American Electric Reliability Corporation ("NERC") that was certified by FERC to establish reliability standards for the nation's transmission systems. NERC's reliability standards apply to regional entities, *e.g.* ISOs and RTOs, as well as to transmission operators, *e.g.* ESI on behalf of the EOCs. NERC's reliability standards are mandatory and intended to mitigate the risk that the transmission system will cause or contribute to customer outages. NERC's reliability standards also provide the basis for determining the necessity for transmission improvements to maintain reliable service in the event of unexpected failures of any generation or transmission facility. EMI therefore at a minimum has an obligation to fund transmission investments to comply with NERC reliability standards (i) to adequately maintain EMI's existing system, *e.g.* replacement of defective equipment and preventative maintenance, and (ii) to improve EMI's system, *e.g.* expand service and implement new security measures.

[6] An important corollary is that ITC is financially stronger due, in large part, to the favorable rate treatment it receives from FERC, which I addressed in Section III.

Q. Please address EMI's first claim that it will have difficulty funding its transmission requirement over the next few years to replace old equipment, install new equipment, and expand its system to meet demand growth.

A. If EMI has a a significant transmission funding requirement, it appears to be due, at least in part, to its own underfunding of transmission investments over the past few years. According to EMI witness Lewis, [Begin HSPM [redacted]

Figure 3: Actual and Forecast EOC Transmission Investments (Jay A. Lewis)

[End HSPM]

Q. Is there a relationship between the capital that the EOCs had to invest to recover from Hurricanes Katrina and Rita in 2005 and the reduction in transmission investments?

A. It is difficult to say. None of the EMI or ITC testimonies address whether any causal link exists between storm recovery spending and reduced transmission investments. I note, however, that during the five year period when transmission investment was reduced, 2005-2009, the EOCs spent [Begin HSPM] [redacted] [End HSPM]

Q. Can you estimate the shortfall in transmission funding for that five year period?

A. Yes. I interpolated what the EOCs would have spent on transmission investments for those five years, 2005-2009, based on the data in Mr. Lewis' Highly Sensitive Figure 3. As shown in Table 12 below, I estimate that the EOCs reduced their transmission investments by [Begin HSPM] [redacted]

[End HSPM]

Q. How did the EOCs explain the reduction in transmission spending?

A. According to informal discussions with Rick Riley, Entergy's Vice President of Energy Delivery, funding for the EOCs as a whole was reduced during that period of time because of low load growth due in large part to the Hurricanes. Mr. Riley explained that transmission investments had low priority within EMI after (i) safety and reliability investments, (ii) regulatory-mandated investments, (iii) investments to serve new load, and (iv) distribution system investments to ensure local reliability. Further, in response to MPUS-54, EMI explained:

> Because Hurricanes Katrina and Rita in 2005, and other storms later, significantly impacted the load of the Entergy Transmission System, especially in southeast Louisiana, some projects that had been planned previously were postponed due to reductions in actual and forecasted load growth in the affected regions. (Underlining added for emphasis.)

Q. Did you attempt to prove or disprove Mr. Riley's contention?

A. No, I did not try to prove or disprove Mr. Riley's contention. However, I offer three observations contradicting Mr. Riley's claim that reduced load growth was the reason for lower transmission investments during the 2005-2009 period.

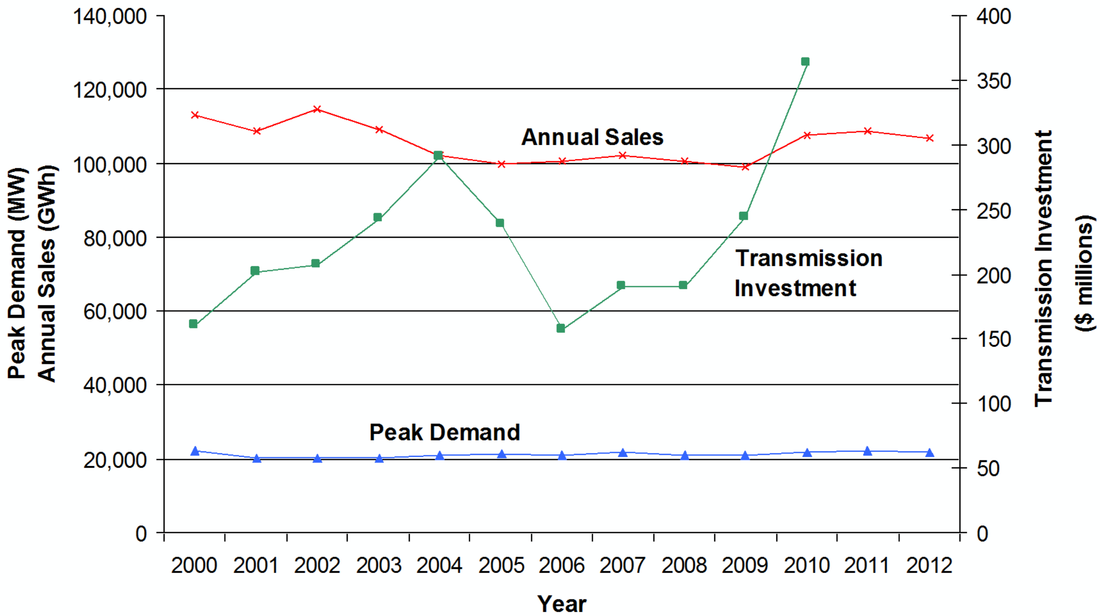
First, I do not think it was coincidence that the EOCs had to spend hundreds of millions of dollars to restore service after Hurricanes Katrina and Rita. It may have been expedient for Entergy to apply funds that had been planned for transmission investments to more immediate needs starting in 2005.

Second, transmission investments are planned and implemented well in advance of the actual need. If load growth was reduced due to Hurricanes Katrina and Rita in 2005, I would have expected transmission investment to continue for some time and then drop off some years later once those investments were completed. This was not the case, however.

Third, I compared the EOC's transmission spending to their annual peak load and retail sales over this period of time. As is illustrated in

Figure **4** below, I found that peak demand and retail sales were relatively flat for virtually the entire period of 2000-2012, including the years immediately after Hurricanes Katrina and Rita. Transmission spending appears to be completely independent of peak load and sales, which is inconsistent with Mr. Riley's explanation.

Figure 4: EOC Transmission Investment versus Peak Demand and Retail Sales
(2000-2012)



Q. Is EMI's concern about the difficulty of funding its expected transmission investments over the next few years supported by Entergy's Form 10-K filing?

A. No. According to Entergy's Form 10-Ks over the past ten years, Entergy has not identified the need to raise significant amounts of transmission capital as a concern and has never mentioned an inability to fully fund its transmission investments.

B. Transmission Investments Have Low Risks and Provide Stable Long Term Returns

Q. Please describe the risks of transmission investments.

A. Utilities throughout North America routinely fund and make transmission investments in the normal course of their business. Most of them view such investments positively due to their (i) low inherent risks, (ii) diversification of the owner's overall risk, (iii) stabilizing influence on revenue requirements, and (iv) provision of an investment opportunity in a low growth economy. The long depreciation period is often viewed as an advantage by transmission owners and investors.

Q. Please explain why transmission is a low risk business.

A. Transmission investments have traditionally been viewed as having low risk because the investments tend to have explicit regulatory approval and thus avoid questions about whether they were prudent or not used and useful. Transmission assets do not have competitors to the same extent that generation assets do; nor do they have variations in fuel costs, emission allowance costs, or other competitive cost factors. Transmission assets provide reliability benefits to RTOs, and once built are virtually never abandoned and written off without cost recovery. The long lives of transmission investments assure owners of a return of and on capital, thus providing a stable source of revenues and earnings. Opportunities to invest in low risk, long-lived transmission assets are particularly advantageous in today's low growth economy. Lastly, if transmission assets are damaged by storms, regulators tend to view restoration costs as necessary for the reliable provision of wholesale service and are likely to approve required repairs and replacements.

Q. Do third parties view transmission investments as low risk with stable returns?

A. Yes, and I provide four examples. First, S&P views transmission investments as low risk and as improving a utility's diversity. S&P provided its framework for rating regulated utilities in its document "Key Credit Factors: Business And Financial Risks In The Investor-Owned Utilities Industry." S&P explained "We view a company that owns regulated generation, transmission, and distribution operations as positioned between companies with <u>relatively low-</u>

risk transmission and distribution operations and companies with higher-risk diversified activities on the business profile spectrum." (Underlining added for emphasis.)

Second, an article in the February 2013 issue of Public Utilities Fortnightly also highlighted the low risk and long-term, predictable financial returns from transmission investments. "Busting the Transmission Trusts" by Ed Krapels, provided as Exhibit SGP-2, discusses the evolving transmission business and the attraction for investors:

> The beauty of transmission infrastructure assets is that they last for decades and, properly designed, can provide annuity-like returns for investors who would happily have some stable returns… For institutional investors, transmission projects are prized assets; they're long-lasting, low maintenance, and critical to their customers, and they typically have a material residual value at the end of their initial financing period.

Third, an article in the September 23, 2011 issue of The Street, "Transmission Lines Are Powerful Investments", discussed how transmission lines are "Among the most dependable utility investments…" The article, which highlighted ITC among other transmission owners, stated that "Unlike most power generators, transmission lines are cost-plus assets, and those assets earn solid returns through good times and bad."[7] Fourth, in response to data request MPUS 1-14, EMI indicated that "…S&P appears further to view transmission as lower risk than other regulated activities."

Q. Are there other benefits of transmission investments?

A. Yes. Transmission helps diversify the business risks and revenues for vertically integrated utilities. On page 18 of his direct testimony, ITC witness Bready pointed out that Moody's

[7] See http://realmoney.thestreet.com/articles/09/23/2011/transmission-lines-are-powerful-investments , accessed June 19, 2013.

Investor Services ("Moody's"), the nation's other prominent credit ratings agency, considers diversification as a positive factor. In its "Ratings Methodology for Regulated Electric and Gas Utilities," Moody's explained that "Diversification of overall business operations helps to mitigate the risk that any one part of the company will have a severe negative impact on cash flow and credit quality."

Q. Did EMI and ITC address whether transmission helps diversification?

A. Yes. In response to data request MPUS 1-14, EMI indicated "…diversification is considered a benefit by rating agencies." In response to data request MPUS-ITC 1-29, ITC confirmed the advantages of diversification: "…as an independent transmission company with no other revenue-generating activities, ITC is less able to withstand disruptions in its revenue stream…"

Q. How do the credit rating agencies view Entergy's diversification after the Transaction?

A. According to EMI's response to data request MPUS 1-16, (i) Moody's stated the Transaction has "…the potential to increase regulatory risks and certain operating risks…" and (ii) S&P stated "…Entergy's business risk will increase somewhat to reflect the reduced contribution of the regulated part of the business."

C. EMI's Second Claim that Transmission Investments Cause a Financial "Strain" Is Unsupported

Q. Do you agree with EMI's second claim that transmission investments are a "financial strain" due to the long depreciation period that stretches out EMI's recovery of invested capital?

A. ITC's claim of "financial" strain was described by Mr. Bready on page 16 lines 5-8 of his direct testimony: "…the transmission investment requirements will place a disproportionate amount of capital pressure on the EOCs, largely due to the high ratio of capital investment needs to cash flow generated by this segment of the business." Mr. Bready's characterization, however, ignores the many positive advantages of transmission investments that I discuss above. Transmission investments do have relatively long depreciation periods, and hence the return of capital is relatively lengthy, leading to relatively low depreciation-related cash flows over the recovery period. But most utilities do not view transmission investments as a "financial strain"; they are, rather, a low risk investment opportunity with stable long term returns.

Q. Is the claimed issue of "financial strain" mentioned in Entergy Form 10-Ks?

A; I did not find any mention of "financial strain" in the Entergy Form 10-Ks over the past three years. Pages 247-268 of Entergy's 2012 Form 10-K, Risk Factors, discussed many business, regulatory, market, and financial risks, but the claimed issue of financial strain due to the long capital recovery period for transmission investments was not discussed.

Q. Did Mr. Lewis address this issue on page 16 and state "…the EOC's transmission business is forecasted to be a negative cash flow business for the foreseeable future"?

A. Yes, but any real world investment with a long depreciation period will have negative cash flow when projected investments are scheduled to rise over time. Cash inflows could only be greater than cash outflows during periods when investments decline over time and could be neutral when investments remain flat. This phenomenon applies to all businesses, not just the electric utility industry.

Q. Is it possible that the EOC's underfunding of its transmission business from 2005 through 2009, per Mr. Lewis' Highly Sensitive Figure 3, has worsened the expected negative cash flow over the next few years?

A. Yes. Rising from a 2005-2009 average of [Begin HSPM] [redacted] [End HSPM] per year to a 2013-2018 average of [Begin HSPM] [redacted] [End HSPM] per year will accentuate the difference between cash outflows for transmission investments and cash inflows due to the return on and of capital.

Q. Is the claimed issue of financial strain mentioned in ITC's Form 10-Ks?

A. I did not find any mention of "financial strain" in ITC's Form 10-Ks over the past three years. Moreover, ITC has made transmission investments its only business, demonstrating that the many advantages of the transmission business outweigh any claims of financial strain.

Q. In its data responses, did EMI address the issue of the long capital recovery period for transmission investments?

A. Yes. In its response to MPUS 1-13, EMI confirmed "Since 1996, transmission capital expenditures have exceeded transmission depreciation." Consistent with my position, long capital recovery periods and the consequential cash outflows being greater than cash inflows are normal for transmission investments.

Q. Would these positive aspects of transmission investments still apply if a utility was facing financial difficulties absent the need for such investments?

A. If a utility were facing financial difficulties due to problems unrelated to its transmission business, then it might well view transmission investments as a financial strain. Vertically integrated utilities have competing generation, distribution, and transmission investment opportunities. In addition, many utility holding companies, such as Entergy, have opportunities to invest in merchant generation. While merchant generation investments provide an opportunity to earn unregulated returns that are greater than returns on regulated assets, those investments can perform poorly as well, increasing pressure on holding companies to retain less net income at the utility operating company level to maintain shareholder dividends.

Q. Is Entergy facing financial difficulties?

A. I have not conducted a detailed analysis to make that determination. However, many of the EOCs have been hit by natural disasters in the past few years that required significant spending for storm restoration. Entergy New Orleans declared bankruptcy in 2005, and Entergy's merchant nuclear plants in New York and Vermont may be forced to retire. Overall, Entergy's consolidated net income, which had been growing steadily for many years, dropped by one-third in 2012.

Q. Could EMI reduce the long depreciation period and improve its recovery of transmission expenditures?

A. Yes, I am not aware of any reason why EMI could not request such recovery treatment for rate purposes from the MPSC if it believes that the current recovery treatment creates a "financial strain".

Q. Can you identify any other financial reason why Entergy would need to divest its transmission business?

A. No. None of the EMI or Entergy witnesses have stated their company is facing financial difficulties. Moreover, I do not know why Entergy would want to shrink its business and reduce its diversification by forgoing the returns from owning these assets.

VII. EMI CAN IMPROVE TRANSMISSION PERFORMANCE WITHOUT THE TRANSACTION

Q. What claims have the Applicants made about the performance of the ITC and EMI transmission systems?

A. The Joint Application stated on page 4 that "…ITC has demonstrated capability to operate transmission systems at a high level of quality of service, and its singular focus on transmission has a proven ability to improve transmission performance and reliability." ITC's claim of singular focus and superior transmission performance is one of the objectives identified in the Joint Application.

Q. On what transmission performance study did ITC rely in comparing ITC's performance with that of its peers?

A. In his prefiled testimony on pages 37, lines 12-20 and page 38, lines 1-8, ITC witness Jipping discussed the SGS Statistical Services Transmission Reliability Benchmarking Study ("SGS Study"). Mr. Jipping noted that SGS (i) is the largest independent benchmarking forum for electric transmission reliability, (ii) provides a comprehensive reliability assessment at an operating company level, and (iii) utilizes five plus years of raw transmission circuit outage data, which includes both sustained and momentary outages.

Q. How are companies analyzed by SGS?

A. Companies are analyzed in comparison to other SGS Study participants based on their region and their peer group.[8] According to SGS, its Studies began in 1995. The 2012 Study covered approximately 50% of the U.S. transmission grid based on mileage. Participating companies provide SGS with a minimum of 5 years of raw transmission circuit outage data. Prior to analysis, SGS works with the participating company to filter and standardize the data into a common format to ensure that all participants' data is handled in a consistent manner.

A. ITC's Claims that ITCT and METC Performed Better than Their Peers

Q. According to Mr. Jipping, how have the ITC operating companies performed?

A. On page 38, lines 13-18 through page 39, line 1, Mr. Jipping referred to the 2012 SGS Study to support the following statement:

> Overall, the ITCT and METC transmission systems are among the best performing of those detailed in the SGS Study. For example in the "All Voltages" category, the report indicates that ITCT and METC are within the top ten percent of best rated companies for sustained outages performance per circuit (Number of Sustained Outages per circuit) as well as for the average duration of circuit outages (in minutes). ITC and METC outperform both their region and their peer group in both categories.

Q. Did ITC select its peer companies, and on what basis does ITC select its peers?

A. In response to a question on how the ITC Peer Group in the SGS Studies were chosen, ITC gave the following response in MPUS-ITC 4-7:

> In selecting the composition of the peer group for purposes of comparison in the SGS Study, ITC strove to include companies that were generally located within ITC's geographic region (which would, therefore experience similar weather

[8] SGS defines four regions for its Study: North Central, Northeast, Southeast, and West. ITC's operating companies are within the North Central region. ITC's peer group includes American Transmission Company, LLC; Duke Energy-Indiana, Duke-Energy-Ohio/Kentucky, Exelon Corp; First Energy, Hydro One Networks, and Xcel-Northern States Power.

patterns) and that possessed transmission systems with reasonably similar size to ITC's transmission system.

Q. Have you verified the claims made by ITC regarding the transmission performance of the ITC operating companies compared to their peers?

A. Yes. I based my review on (i) an analysis of the data provided in ITC's responses to MPUS-ITC 1-111 and MPUS-ITC 1-114 and (ii) an independent review of the SGS Study reports, as provided.

Q. Please explain the methodology used in your review.

A. My first analysis relied on performance indices presented in Mr. Jipping's testimony – Average Circuit Outages Sustained ("ACOS") and Average Circuit Outage Duration ("ACOD")[9] for the four years 2008-2011 for which data was provided for all the operating companies and the peer group. I selected these two indices to be consistent with Mr. Jipping's direct testimony. I created a side-by-side comparison of the average ACOS and ACOD data for the three ITC operating companies and the peer group as illustrated below in

[9] ACOS represents the total number of sustained (> 60 seconds) circuit interruptions in a unit time period divided by the number of circuit-years. ACOD represents the duration minutes of sustained circuit interruptions (> 60 seconds) in a unit time period divided by the number of circuit-years. Lower scores indicate better performance for both measures.

Figures 5 & **6: ITC Operating Companies and Peers Transmission Performance**. [Begin HSPM]

Figures 5 & 6: ITC Operating Companies and Peers Transmission Performance
(2008-11)
Average Circuit Outages Sustained **Average Circuit Outage Duration**

[redacted]

[redacted]

Figure 7: Transmission Availability Composite Score for ITC Operating Companies and Peers
(Average 2009 – 2011)

[End HSPM]

Q. How does TACS compare to the ACOS and ACOD indices?

A. TACS is an aggregated metric which uses five years of age-weighted outage data. TACS is heavily weighted towards more recent outage data (80% on the most recent two years and 20% on the preceding three years). ACOS and ACOD, on the other hand, provide yearly performance results.

Q. Did Mr. Jipping or any other ITC witness present TACS data in his testimony?

A. No.

Q. How did the ITC operating companies perform relative to ITC's peers with regard to TACS?

A. Keeping in mind that high scores indicate superior performance, (i) ITCT outperformed the peer group, (ii) METC's performance was comparable to the peer group, and (iii) ITCMW underperformed the peer group.

Q. Why did ITCT and METC perform better or comparably to the peer group while ITCMW performed worse than the peer group?

A. According to Mr. Jipping's prefiled testimony on page 39, lines 4-12:

> ITCT and METC are the two systems that ITC has owned and operated the longest. ITCT has been an ITC company since 2003; ITC acquired METC in 2006. ITC has had more time to implement its corporate policies for these two systems, and this has resulted in these two companies being among the best-performing systems of

> those detailed in the SGS Study. ITC acquired ITCMW in December 2007 and began operating and maintaining the system in 2009. Since this acquisition is quite recent, the benefits of ITC's operations and maintenance practices have not been fully realized in the ITCMW system, and the system does not yet perform as well as our longer-held Michigan companies. (Underlining added for emphasis.)

B. SGS Studies Indicate the ITC Operating Companies Performed Better than EMI and the EOCs

Q. According to ITC and Entergy, how have the ITC operating companies generally performed in comparison to the EOCs?

A. On page 13, lines 14-19 of his direct testimony, Entergy witness Riley noted that:

> As discussed by ITC witness Jon Jipping, the reliability performance of ITC's subsidiaries, International Transmission Company, d/b/a ITC Transmission ("ITCT") and Michigan Electric Transmission Company, LLC ("METC"), exceeds the performance of their region and peers, and they are leaders in the industry overall with respect to reliability performance. Additionally, the performance of those two ITC operating companies exceeds the performance of the EOCs' transmission systems.

In the response to MPUS-ITC-2-5, ITC made a similar statement regarding the performance of ITC and the EOCs:

> Two of the reliability benchmarks ITC relies on to demonstrate system availability performance are sustained outage frequency and average circuit outage duration. Through discussions with Entergy, ITC has come to learn the relative performance of both transmission systems. ITC's Michigan transmission system performs at a much higher level of availability than the Entergy transmission system; therefore one of the immediate goals of ITC would be to improve sustained outage frequency and average circuit outage duration.

Q. Have you verified the claims made by the Applicants regarding the performance of the ITC transmission system compared to EMI and the EOCs?

A. Yes, I have. I used the same approach and methodology that I used to verify ITC's performance relative to its peer group. The Joint Application did not include the SGS Studies' data for EMI, so I requested the relevant data (MPUS-EMI/ITC 2-12 and MPUS 3-11) and reviewed the respective SGS Studies for the EOCs. I also reviewed the ACOS, ACOD, and TACS data for EMI, the EOCs, and the ITC operating companies.[11]

Q. How have the ITC operating companies performed compared to EMI and the EOCs as a whole?

A. [redacted] compare the ACOS and ACOD data for the ITC operating companies to EMI and the EOCs. The figures show that (i) the three ITC operating companies, particularly ITCT and METC, outperformed EMI and the EOCs and (ii) EMI performed worse than the EOCs in aggregate. [Begin HSPM]

[redacted]

[redacted]

[redacted]

[redacted]

[11] "All EOC" aggregates the data for all of the Entergy operating companies – EMI, ETI, ELL, EGSL, ENOI, and EAI. "All ITC" aggregates the data for the ITC operating companies – ITCT, METC, and ITCMW.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Figure 11: Transmission Availability Composite Scores for EMI and EOCs

[End HSPM]

C. ITC Did Not Support Its Claim of Improved Transmission Performance Over Time

Q. Do you agree that the ITC operating companies' transmission systems generally have performed better than the EMI transmission system?

A. Yes, but I do not know if their performance improved under ITC ownership.

Q. Why are you unsure the Transaction will result in improved performance of the EMI transmission system?

A. ITC has not presented quantitative evidence, as tracked by the SGS study, that, over time, it has improved the transmission performance of systems it has acquired. In prefiled testimony, page 40, lines 18-22, ITC witness Jon Jipping claimed the performance of its operating companies improved over time. However, when asked to provide the SGS Study data behind this claim of improved performance, ITC in its response to MPUS-ITC 1-116, stated that:

> The performance improvements stated by Mr. Jipping are based upon the number of sustained outages that are caused by transmission system equipment. This is a different metric than Average Circuit Duration and Number of Sustained Outages

per Circuit as tracked in the SGS Reliability Benchmarking Study and as referenced in this question.

I do not understand why ITC would choose to use a different metric than what is tracked in the SGS Study. Moreover, ITC has neither defined (i) specific investments it will make to the EMI transmission system nor (ii) specific performance improvements that would result from such investments.

Q. Does ITCMW's relatively poor transmission performance regarding ACOS and ACOD, along with Mr. Jipping's claim of the limited time ITC has had to operate and maintain ITCMW's system, provide any indication of how long it will take ITC to improve EMI's performance after the Transaction?

A. No. ITC has not presented any SGS Study data for the period prior to its acquisitions that would indicate if or by how much the performance of its operating companies has improved. The data ITC provided is for the systems after they were acquired, so there is no way of knowing if and by how much the systems improved.

For example, the ITCMW ACOS and ACOD data provided in MPUS-ITC 1-111 are only for 2008-2011. Even though ITCMW's performance is below that of the other ITC operating companies, no SGS Study data were provided in prefiled testimony indicating if performance has improved since it was acquired. I note that ITC had two years to study the ITCMW transmission system so that it could begin implementing improvements as soon as it began operating and maintaining it in 2009.

Moreover, ITC has provided neither a time frame in which it will improve EMI's transmission performance nor an estimate of the magnitude of any expected improvement. Since a detailed transmission analysis was beyond the scope of my work for the Transaction, I recommend that any MPSC proceeding evaluating EMI's transmission business include the issues of (i) how long it will take to improve EMI's transmission performance and (ii) whether some tangible and verifiable demonstration of improvement in transmission performance over a given time period should be required.

D. The Transaction is Not Necessary for EMI to Improve Transmission Performance

Q. In light of the SGS performance data you reviewed, is the Transaction necessary to improve the performance of the EMI transmission system?

A. No. Nothing in the prefiled testimonies and data responses has convinced me that EMI needs to transfer its transmission system to ITC to achieve better performance. There are at least two reasons for my conclusion.

First, as explained earlier, ITC has not presented SGS Study evidence before and after its acquisitions demonstrating that, over time, it has improved the transmission performance of systems it has acquired. The data that was provided is generally for the period after ITC assumed operations.

Second, as explained earlier, ITC has neither (i) defined the specific investments it will make to the EMI transmission system nor (ii) estimated the performance improvements that would result from such investments.

Q. Do you have any additional concerns about EMI's ability to improve the performance of its transmission system?

A. Yes. I have concerns about the relationship between the limited funding of EMI's transmission business over the past few years and its consequential performance. First, I note that EMI's transmission funding categories include: (i) the Base Capital Plan (also referred to as the Construction Plan) of new projects to expand the existing system and ensure reliability, (ii) Infrastructure Replacement Capital to replace old and outdated equipment, and (iii) Field Operations and Maintenance ("O&M") expenses for regular and periodic maintenance (including preventative maintenance) to ensure the continued reliability of the existing transmission system.

A well-funded transmission system with adequate funding for all three categories will certainly perform better than an under-funded transmission system, all other things being equal. While under-funding may not create problems that are immediately visible, persistent under-funding may create a situation that will eventually result in major reliability problems and extraordinary funding to correct those problems. As EMI noted in its response to MPUS IDR 1-1:

[Begin HSPM]

[redacted]

[redacted]

[End HSPM]

Q. Is it your opinion that an adequate level of transmission funding will improve EMI's transmission performance?

A. Yes.

Q. Do you have any other evidence to believe that EMI has been under-funding its transmission system?

A. Yes. First, Mr. Lewis's Highly Sensitive Figure 3 indicates that funding for the EOC's Capital Plan was cut back in 2005-2009 as I discuss in Section VI. Second, in its response to MPUS IDR 1-1, EMI presented the Infrastructure Capital Replacement Program for EMI and the Entergy System as a whole that also indicates the EOC transmission systems have been under-funded: [Begin HSPM]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[End HSPM]

Q. Do EMI's transmission O&M activities receive adequate funding?

A. No. [Begin HSPM] [redacted]

Table 13: EMI Transmission O&M Funding Levels and Gaps

	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]
	[redacted]	[redacted]

[End HSPM]

Q. What in your opinion would help improve the transmission performance of the EMI system?

A. In my opinion, there are two actions that would improve the performance of EMI's transmission system. First, EMI needs to pay more attention to its transmission system by addressing the backlog in replacing aging infrastructure and completing 100% of the maintenance plan for the affected programs as discussed above. Second, the EMI transmission system requires adequate funding for capital expenditures and for O&M expenses to improve performance and to avoid more serious problems in the future. As I discuss earlier, EMI's parent company, Entergy, may not have provided adequate funding, especially in 2005-2009. This issue of transmission funding and performance should be pursued by the MPSC in a separate transmission proceeding. An adequate level of funding would likely improve EMI's transmission performance, regardless of whether ITC or EMI owned those assets.

Q. Has EMI confirmed the need for additional funding to improve transmission performance regardless of ITC or EMI ownership?

A. Yes. In response to MPUS 4-8 EMI noted:

> EMI believes additional funding would be necessary in order to improve performance under either a stand-alone transmission company scenario or in the case of the Proposed Transaction.

Q. Is "singular focus", as touted by ITC, necessary for EMI to improve its transmission performance?

A. No. As I have noted above, to improve performance, EMI needs to pay more attention to its transmission system and provide it with adequate funding. Without adequate attention and funding, singular focus is just a catch phrase.

VIII. IT IS PREMATURE TO ASSUME THAT EMI'S MISO MEMBERSHIP CANNOT ACHIEVE THE CLAIMED REGIONAL PLANNING BENEFITS WITHOUT ITC OWNERSHIP

Q. What have the Applicants claimed will the Transaction accomplish for regional transmission planning?

A. According to page 4 of the Joint Application, "…ITC will bring a regional view to transmission planning and operations that will include transparent collaboration with all stakeholders…the ITC Transaction will…lead to a more comprehensive planning process and a broader regional view than what could be accomplished otherwise."

Q. Please define your understanding of the term "regional transmission planning"?

A. Regional transmission planning involves identifying transmission solutions that meet a region's needs more efficiently or cost-effectively compared to solutions prepared by an individual utility, where that utility considers only the needs of its own service territory. A proper regional transmission planning process should develop a comprehensive regional transmission expansion plan that (i) identifies short-term and long-term transmission needs, (ii) covers a broad geographic area, (iii) identifies solutions that improve reliability and wholesale market efficiency, and (iv) is consistent with state energy policies.

Q. Does MISO have an established process for developing its regional transmission expansion plan?

A. Yes. The MISO Transmission Expansion Plan (MTEP) is developed annually consistent with the principles established by FERC in its Orders 890 and 1000. The MTEP process is described in Attachment K of the MISO Open Access Transmission Tariff ("OATT").

Q. Please describe the transmission planning principles set by the FERC in its Order 890.

A. To remedy the potential for undue discrimination in transmission planning activities, FERC required each public utility transmission provider to develop a transmission planning process that satisfies nine principles and to clearly describe that process in a new attachment to its OATT (Attachment K). The Order 890 transmission planning principles are: (i) coordination, (ii) openness, (iii) transparency, (iv) information exchange, (v) comparability, (vi) dispute resolution, (vi) regional participation, (viii) economic planning studies, and (ix) cost allocation for new projects.

Q. What were the objectives of the FERC's Order 1000?

A. In Order 1000, FERC directed all public utility transmission providers to develop processes to engage in regional transmission planning with other public utility transmission providers, consider transmission needs driven by federal, state, and local public policy mandates, participate in broader interregional transmission coordination, and establish new cost allocation methods for regional and interregional transmission facilities that result from the Order 1000 processes. In addition, all public utility transmission providers, including RTOs (such as MISO), were required to remove from their tariffs and agreements any provisions that grant a "federal right of first refusal" to a current ("incumbent") public utility transmission provider to construct regional transmission facilities if the costs of such facilities are allocated to customers outside of the incumbent utility's retail distribution service territory or footprint.

Q. Is MISO's OATT in compliance with the FERC transmission planning regulations?

A. Yes, it is.

Q. How will joining MISO affect EMI's transmission planning process absent the Transaction?

A. As a transmission owner-member of MISO, EMI will continue developing its own transmission expansion plans as well as plans to modify its existing transmission infrastructure. MISO, jointly with all of the stakeholders, will review and evaluate the EMI proposed plans on a broader regional basis to find cost-effective transmission solutions beyond EMI's limited perspective before such plans are included in the MTEP.

Q. What categories of the transmission projects exist under the MISO transmission planning process that may be considered for the regional cost allocation?

A. MISO has four basic categories of transmission projects: Baseline Reliability Projects, Transmission Access Projects, Market Efficiency Projects, and Multi-Value Projects ("MVP").

1. Baseline Reliability Projects are required to meet reliability standards.

2. Transmission Access Projects are designed to fulfill generation interconnection requests as well as requests for point-to-point or network transmission service.

3. Market Efficiency Projects are designed to relieve congestion and provide economic benefits in terms of reducing production costs and locational marginal energy prices.

4. MVPs are a relatively new category that facilitates cost allocations for regional projects that (i) provide economic values greater than the costs, *e.g.* reducing congestion, lowering

production costs and/or (ii) enable compliance with state and federal public policy requirements.

There are also other types of transmission projects that are not considered for the regional cost allocation. These would normally include minor and local transmission projects that might operated at a sub-transmission voltage level.

Q. Can state regulatory commissions participate in the MISO transmission planning process?

A. Yes, they can and are strongly encouraged to participate as provided for in the MISO OATT. State regulators provide MISO with input and review proposed transmission expansion projects as the MTEP is developed. According to page 12, lines 18-20 in the direct testimony of ITC witness Vitez, MISO generally considers "…inputs provided from state regulatory authorities having jurisdiction over any of the Transmission Owners and by the Organization of MISO States ("OMS")." On page 14, lines 3-8, Mr. Vitez further stated that:

> …The OMS was formed in 2004 as a non-profit, self-governing organization of representatives from each state with regulatory jurisdiction over entities participating in the MISO. As indicated on its website, the purpose of the OMS is to coordinate regulatory oversight among the states, including recommendations to MISO, the MISO Board of Directors, FERC, other relevant government entities, and state commissions as appropriate."

In its Order in Docket 2011-UA-376 regarding EMI joining an RTO, the Commission found that "it would have the opportunity, both individually and through OMS, to participate actively in MISO's decision-making process and help shape the outcome of issues of importance to EMI's ratepayers, including transmission planning and transmission cost allocation."

Regardless of any decision on the Transaction, my recommendation would be that the

Commission devotes the necessary resources to actively monitor and participate in the MISO transmission planning process.

Q. How would the Transaction affect how Mississippi's transmission needs are addressed in MISO?

A. In its responses to data requests MPUS-ITC 1-78(a) and (e), ITC stated that it will participate in the development of the MISO's MTEP consistent with the Appendix I Agreement that ITC has filed with FERC. EMI will participate in the development of the MTEP as well, if the Transaction does not proceed. I see no reason why EMI, guided by the Commission's preferences (which themselves will reflect a regional perspective given the Commission's participation in the Organization of MISO States) cannot develop and pursue a regional perspective.

Q. Is there a possible disadvantage to ITC asserting Mississippi transmission needs in the MISO arena, as compared to EMI asserting those needs?

A. Yes. Consider the situation of non-transmission alternatives, such as distributed generation or demand-side resources, which can represent cost-effective solutions to regional needs. ITC's "singular focus" on transmission means that transmission is its only profit center. EMI, on the other hand, has an obligation to serve its retail load on a least-feasible-cost basis. Given this difference, EMI will be more likely than ITC to explore, consider, propose and argue for non-transmission alternatives than will ITC, especially where the Commission has directed EMI to do so. Such non-transmission alternatives could be identified and studied on a parallel track with the transmission projects either through a state regulatory process or through the MISO planning process.

Q. If the Transaction is not approved, would EMI be able to propose and implement not just reliability transmission projects but also market efficiency transmission upgrades?

A. Yes, it would. Absent the Transaction, EMI would be able to identify any market inefficiencies, *e.g.,* resulting from transmission congestion, and propose economic or market efficiency transmission upgrades, perhaps in concert with other EOCs or other MISO members. As a member of MISO, EMI would propose these upgrades in the context of the MTEP development at MISO. And the Commission, having full jurisdiction over EMI (which it will not have over ITC) can guide and direct EMI's proposals.

Q. Will the Transaction lead to "…a broader regional view…" as claimed in the Joint Application and specifically addressed by Mr. Bunting?

A. No. As I explained above, there is no reason why EMI's membership in MISO will not lead to regional transmission planning that is independent, transparent, and comprehensive. Since ITC's transmission assets are predominantly in Michigan, Iowa, and Kansas, there do not appear to be any realistic opportunities to plan transmission investments between ITC's and Entergy's service territories.

IX. IT IS PREMATURE TO ASSUME THAT EMI'S MISO MEMBERSHIP, WITHOUT THE TRANSACTION, WILL NOT ELIMINATE CONCERNS ABOUT ITS ANTICOMPETITIVE BIAS

Q. What have the Applicants said about the Transaction's ability to eliminate EMI's bias in transmission practices?

A. EMI does not believe it has any bias in transmission practices. The Applicants do acknowledge that there is a perception of bias. According to page 4 of the Joint Application:

> …By eliminating any perception of bias in transmission planning, the ITC Transaction will encourage market participation and disclosure of information by third parties, leading to a more comprehensive planning process and a broader regional view than could be accomplished otherwise.

The perceptions of bias acknowledged by Applicants are described in Mr. Bunting's Direct Testimony (pp. 9-10) and also at (MPUS 1-18(a); MPUS 1-20; Welch at page 13 lines 6-10, page 44 lines 5-11, page 45 lines 12-14. They include merchant generators' belief that (i) Entergy plans and operates its transmission system in a discriminatory manner and (ii) the information they share with Entergy's transmission department for planning purposes may be shared with Entergy's generation business. Mr. Bunting asserts (at pp. 11-12) that "[o]nly the move to an independent transmission company model will eliminate any lingering perception of bias arising from the common ownership of transmission and generation that may affect how some merchant generators choose to participate in the transmission planning process."

Q. Is the only way to eliminate any Entergy biases, and any perceptions of Entergy biases, for Entergy to sell its transmission assets to ITC?

A. No, not if MISO and its transmission owners, including the EOCs, comply fully with the MISO OATT, MISO rules and procedures, and the requirements of FERC Orders 888, 889, 2003, 2000 and 1000.

Q. How does MISO address the need for independence?

A. In the context of transmission policy, "independence" refers to decisions and information about transmission access being made independent of the influence of market participants. MISO is independent of market participants by virtue of meeting FERC's independence criteria established in Order No. 2000. . Further, all transmission owners who join MISO are signatories of the Transmission Owners Agreement ("TOA") under which they turn over "functional control" of their transmission facilities to MISO. The MISO Open Access Transmission Tariff (OATT) then defines how MISO operates those transmission systems. Moreover, the transmission owners themselves have "functionally unbundled" their transmission service from their generation businesses as required by FERC Order Nos. 888 and 889. The intent of these orders, along with Order No. 2000 (which authorizes RTO and establishes their "minimum characteristics" and "minimum functions)," is to ensure that entities that compete with the transmission owner's generation have access to the transmission facilities, and to information about the facilities' availability, on a basis that is comparable to the access that the transmission owner's generation business has.

. By meeting all MISO requirements and signing the TOA, EMI will satisfy the requirements for independence that FERC has established.

Q. Would ITC's ownership of EMI's transmission make a difference in terms of independent operation and planning?

A. It is possible, but there is no basis for comparison until we see how EMI functions as a new MISO member. MISO has robust, fair, and transparent rules that govern generator interconnections, day-ahead generator commitments, real-time generator dispatch, transmission operations (particularly congestion management), and cost allocation. Once EMI joins MISO, MISO will make all of these planning, dispatch, and operational decisions, so that EMI will have difficulties if it tried to favor its own generation assets. If any perceptions of bias continue to exist, such concerns would be resolved through MISO's established dispute resolution process under its OATT. EMI would only be able to optimize its local sub-transmission system; this, however, in no way will affect the high voltage transmission grid. Even Mr. Bunting stated that "Certainly, MISO membership will help mitigate this concern" on page 12, line 1 of his direct testimony.

Q. Did the Applicants attempt to quantify the benefit of eliminating this perception of bias?

A. No. The Applicants failed to quantify any benefits directly attributable to an additional increment of independence derived from ITC's ownership. They discuss the benefits in qualitative terms only. Further, any qualitative benefit from the elimination of the perception of bias is dwarfed by the numerous deficiencies of this Transaction as discussed by myself and Staff witness Hempling.

X. EMI MEMBERSHIP IN MISO WILL PROVIDE THE BENEFITS OF THE MISO DAY 2 MARKET ABSENT THE TRANSACTION

Q. Did the Applicants claim any Transaction benefits attributed to participation in the wholesale energy markets?

A. Yes. Mr. Bunting claims (page 4 of his direct testimony) that "[t]he ITC Transaction aligns ITC's broader regional approach to transmission planning with the broader regional economic dispatch that MISO will institute. That alignment will foster a more robust Day 2 market and a lower total delivered cost of energy to customers over time."

Q. What is the MISO's Day 2 energy market?

A. MISO's Day 2 energy market is the next step in the evolution of MISO's wholesale market. The MISO wholesale energy market now includes day-ahead unit commitments, a real time balancing market, and a co-optimized ancillary services market. Generators are required to submit energy offers into both the day-ahead and real time markets. The marginal committed resources will normally set the locational marginal energy prices that include congestion components, while financial transmission rights are used to hedge congestion risks.

Q. Will participation in the MISO Day 2 market result in any benefits to the market participants and to EMI in particular?

A. There are potential benefits and costs. One clear benefit is that a Day 2 construct provides a formal, transparent mechanism to determine redispatch of resources taking into account the economic offers of all market participants. The efficient operation of a Day 2 market hinges largely on quantifying congestion costs and redispatching system resources. However, as was found by the MPSC in docket 2011-UA-376, "presently, EMI does not know whether its costs associated with congestion on its system will increase or decrease upon joining and transitioning to an RTO." In its Order in docket 2011-UA-376 ¶59, the MPSC ruled that "any Commission approval for EMI to join an RTO must be conditioned on allocation of congestion management rights sufficient to appropriately and fairly hedge against congestion costs. With such condition, the Commission finds that EMI's native load customers will continue to have a first priority to the use of EMI's transmission facilities and that EMI's customers will be served on the same basis as before EMI joins MISO." If the condition is met, the MISO Day 2 market will be a big improvement absent the Transaction.

Q. How would the Transaction affect this condition of the MPSC's approval for EMI to join MISO?

A. In my opinion, the effectiveness of this condition would be greatly diminished because the MPSC would have no jurisdiction over ITC, particularly over congestion cost mitigation. If participation in the MISO Day 2 market were to reveal significant EMI transmission congestion and ITC did not effectively address it, in my view the MPSC's ability to enforce this condition in its Order would be very limited.

Q. Did EMI or ITC present any evidence in support of the claim that the Transaction will foster a more robust Day 2 market?

A. No.

Q. Do you agree with Mr. Bunting that the Transaction will foster a more robust Day 2 market and a lower total delivered cost of energy?

A. Mr. Bunting offers no facts by which to assess him statement. Without any such facts, the Commission should not subject Mississippi ratepayers to the higher costs associated with ITC's FERC-set rates without first seeing how EMI's presence in MISO will work out. Under the MISO OATT, the robustness of the Day 2 market is assisted by its features of independence, transparency, competitiveness, and fairness, assuming all the transmission owners comply with all MISO rules and all FERC orders.

Q. Does this conclude your testimony?

A. Yes, it does.

COMMONWEALTH OF MASSACHUSETTS)

COUNTY OF SUFFOLK)

SETH G. PARKER, Vice President of Levitan & Associates, Inc., being first duly sworn, deposes and says that the statements contained in the foregoing Testimony to the Mississippi Public Service Commission Re: Joint Application for Transfer of Ownership and Control of Entergy Mississippi's Transmission Facilities and Assets to Transmission Company Mississippi, LLC are true and correct to the best of his knowledge, information and belief.

Seth G. Parker
Vice President, Levitan & Associates, Inc.

Subscribed and sworn to before me this the 20th day of June, 2013.

Notary Public

My Commission Expires: 2-1-2019

PHYLIS J. FUTCH
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 1, 2019

SETH G. PARKER

SUMMARY

An economic and financial manager with an international background in competitive markets and power project development, evaluation, financing, and divestiture / privatization / acquisition. Key experience includes transaction support, risk management, credit / collateral provisions, modeling and analyses of conventional / wind / renewable power resources, inter-regional transmission projects, market design, and asset valuation.

PROFESSIONAL EXPERIENCE

1998 - **Levitan & Associates, Inc.**
Principal & Vice President
Managing Consultant

1988-1998 **Stone & Webster Management Consultants (US and UK)**
Vice President
Assistant Vice President
Executive Consultant
Senior Consultant

1984-1988 **J. Makowski Associates, Inc.**
Financial Manager - Ocean State Power

1981-1983 **ThermoElectron Energy Systems**
Senior Financial Analyst

1978-1981 **Pacific Gas and Electric Co.**
Project Financing Analyst

CONSULTING ASSIGNMENTS

MARKET & POLICY ANALYSIS

Assisted the Vermont Department of Public Service (DPS) on power market, reliability, environmental, and socio-economic issues regarding extending the Vermont Yankee Certificate of Public Good, before the Vermont Public Service Board.

Advised the Connecticut Pubic Utilities Regulatory Authority (PURA, previously the DPUC) on financial policy issues of pending Northeast Utilities / NStar merger.

Evaluated alternative resource options and the market price and socio-economic impacts associated with the potential retirement of Vermont Yankee on behalf of the Vermont DPS.

EXHIBIT
SGP-1

Assessed the economic costs and benefits of a proposed HVAC transmission line versus generation and demand-side alternatives; utilized in filings to the Massachusetts Energy Facilities Siting Board on behalf of project sponsor NStar.

Advised the Virginia State Corporation Commission Staff on commercial and technical issues for the HVAC Potomac-Appalachian Transmission Highway (PATH) project, including need, cost, timing, market impacts, and alternative transmission solutions.

Advised three New York City (NYC) generators on the NYISO installed capacity demand curve reset process for 2011/12 – 2013/14 focusing on peaker proxy technology / cost, transmission deliverability, site requirements, and net energy and ancillary service revenue calculation.

Provided written testimony on resource options and economics on behalf of Shell Energy NA regarding Dominion Virginia Power's (DVP's) 2009 Integrated Resource Plan; testified before the Virginia State Corporation Commission.

Prepared expert report and testimony on the DVP 2007 Solicitation for 2011 Unit Capacity for Shell Energy NA that addressed capacity needs, bidder qualifications, best competitive procurement practices, and bid evaluation methodology.

Provided advice on financial, operational, decommissioning funding, and ratepayer risk issues to the Vermont DPS regarding Entergy's application to restructure the ownership of its merchant nuclear plants, including Vermont Yankee.

Prepared major deregulation study for the Maryland Public Service Commission that evaluated new generation, transmission, and demand-side options; evaluated divestiture's financial impact on generation fleet and to parent company; updated study for rate-base utility or power authority generation ownership.

Advised New York Power Authority (NYPA) on inter-market transactions, including power economics, interconnection requirements, grid upgrades, reliability impacts, permit issues, and regulatory considerations.

Advised generator group on PJM's proposed Reliability Pricing Model (RPM) capacity valuation mechanism, including gas turbine capital & operating costs, net revenues, financing charges, etc.; represented group's interests at FERC.

Assessed market prices and congestion costs relative to competing generation and transmission project bids for Long Island Power Authority (LIPA); prepared ICAP forecasts across northeast markets and commercial analysis of HVDC cable proposals.

Evaluated market potential of PJM cable exports into NYC for potential purchaser of Linden simple / combined cycle project, including cable expansion issues.

Managed the update of NYISO's capacity market demand curve parameters for 2005/06 - 2007/08 based on levelized costs of gas turbine peaker capacity (CONE), including net energy revenues from multi-regional simulation model with stochastic treatment of hourly loads; evaluated demand curve slope and zero-crossing point; achieved consensus with stakeholder group; submitted report to FERC for approval.

Advised counsel for Mirant Equity Committee regarding NYISO, ISO-NE, and PJM capacity markets and the demand curve mechanisms used to forecast ICAP prices.

Established feasibility of inter-pool wheeling into load pocket to reduce congestion costs; quantified maximum benefit and reliability / portfolio effects for LIPA.

Evaluated alternatives to the Indian Point Nuclear Power Station for Westchester County and its Public Utility Service Agency, including power and local economic implications of shut-down, repowering, replacement with transmission / conventional / renewable resources, continued operation, and license extension.

Estimated market value of incremental energy and capacity from the Bonanza coal plant owned by the Deseret Generation and Transmission Cooperative in Utah.

Prepared analysis of US power markets and merchant plant business structures for overseas investor; recommended target areas and distressed asset screening model.

Advised stakeholder group on technical, environmental, operational, and regulatory issues of power and gas infrastructure projects across Long Island Sound and in southwest Connecticut for the Institute for Sustainable Energy; facilitated revised guidelines for Connecticut Siting Council.

Prepared long-term market price forecasts by sub-regions in New England, New York, and PJM to capture congestion effects for PECO Energy's acquisition of Sithe assets.

Power market analysis of Salem Harbor conversion to gas for ISO-NE White Paper.

Assessed market potential for independent power producers throughout the US; identified competitive capabilities of utility and non-utility developers and of engineering firms.

ISO-NE cogeneration marketing and permitting assistance for Unitil gas utility.

Assessed state-by-state future demands for cogeneration systems based upon industrial activities, fuel costs, utility purchase and sales rates, and regulatory climates.

PROJECT DEVELOPMENT

Advised a confidential client on HVDC cable system operational issues, including performance risks, O&M issues, and voltage-source converter technology.

Assisted NRG with economic analysis, financing structure, debt and equity sources, finance rates, PPA terms, and credit issues for proposed offshore wind project.

Advised Maine Department of Transportation on proposed LNG terminal project, including feasibility, site, safety, comparative economics, and pipeline routing.

Provided commercial advice on 15 MW cogeneration upgrade for New York University, including economic feasibility, contract structure, and utility backup arrangements; advised on renewable wind project development / contractual support; evaluated micro grid proposal for NYU's Brooklyn campus post-Superstorm Sandy.

Advised The Stanley Works on business strategy / financing of 8MW hydro plant.

Completed pre-financing development work (permits, construction, and financing) for Ocean State Power Phase I, a 225 MW combined cycle plant in Rhode Island.

PROJECT & DUE DILIGENCE EVALUATIONS

Evaluated the status of proposed nuclear plant upgrades for the New Jersey Board of Public Utilities in support of its Long-Term Capacity Agreement Pilot Program (LCAPP), including Nuclear Regulatory Commission decisions on uprate applications.

Conducted economic evaluation of the Deepwater Block Island offshore wind project for the Rhode Island Economic Development Corporation, including PPA pricing, risk allocation, price suppression benefits, regional economic impacts, and other issues.

Forecasted expected operating regime and changes in market power prices and regional air emissions for Bayonne 512 MW gas turbine peaker plant with HVAC underwater cable lead into NYC; report was used for Bayonne's Article VII Certificate application.

Prepared revenue and operating expense projections of PJM coal and combined cycle plants being sold by AES, including capacity revenues under alternative scenarios.

Conducted financial analysis of rival cogeneration projects at New York University, including operating cost savings, tax-exempt debt terms, and credit rating impacts; prepared project valuation and recommendation for Financial Committee.

Advised the New York State Housing Finance Agency as lender to a cogeneration project, including project review, contract negotiation, and financing terms.

Managed due diligence review, construction monitoring, and acceptance testing of cogeneration, combined cycle, fluidized bed, and industrial projects for commercial lenders, investment banks, and government, bilateral & multilateral agencies:

- Brooklyn Navy Yard, 220 MW cogeneration plant, New York
- Derwent Cogeneration Project, 210 MW cogeneration plant, England
- East Java Power, 500 MW combined cycle plant, Indonesia
- EES Coke Battery, 900,000 ton per year coke facility, Michigan
- Guna Power Project, 347 MW naphtha / gas combined cycle plant, India
- Hadley Falls, 43 MW hydroelectric plant, Massachusetts
- Hub Power, 1,200 MW, $1.8 billion, World Bank-supported plant, Pakistan

- Indiana Harbor Coke Battery, 1.3 million ton per year facility, Indiana
- Kot Addu, 1,600 MW oil / gas combined cycle plant, Pakistan
- Midland Cogen Venture, 1,370 MW $2.3 billion cogen plant, Michigan
- Niagara Falls Resource Recovery, 800,000 ton per year plant, New York
- Panther Creek, 80 MW fluidized bed power plant, Pennsylvania
- Warrior Run, 180 MW fluidized bed power plant, Maryland
- York Research, financing of four plants, Texas, New York, and Trinidad

Established economic value and financing plan for existing 43 MW Massachusetts hydroelectric power plant in support of acquisition and financing by a municipal utility.

Evaluated operating characteristics and economics of cogeneration expansion plans for the Massachusetts Institute of Technology, and recommended phased-in scheduling.

Managed due diligence reviews of US coal and gas-fired power plants in support of Manweb (UK) equity investments; helped negotiate transaction modifications.

Recommended cogen plant design and financing plan for Turkish Industrial Zone.

Evaluated the feasibility of converting the Bataan nuclear power station in The Philippines to a gas-fired combined cycle plant for Shell Oil Company.

AUCTIONS & PROCUREMENTS

Independent monitor on behalf of the California Public Utilities Commission for Southern California Edison's Fixed Price Request for Offers from non-gas fired Qualifying Facilities; authored Independent Evaluator Report for the Commission.

Agent for the New Jersey Board of Public Utilities to administer the LCAPP to develop 2,000 MW of new capacity; responsible for evaluating bidder financial strength / development expertise, contract drafting, and security (letters of credit and cash in escrow) provisions.

Retained by the Illinois Power Authority as Procurement Administrator for the 2008, 2009, 2010, and 2011 competitive procurements of energy, capacity, and RECs, the 2010 procurement of long-term renewable resources, and the 2012 Rate Stability energy and RECs procurement for the Ameren Illinois Utilities; responsible for benchmark pricing, finance, credit, security, performance, and related contract issues.

Advised the Connecticut PURA on economic costs / benefits, credit / collateral terms, and other contract conditions for long-term PPAs.

Conducted power and fuel price forecasts and financial analysis for a confidential equity investor in the auction of the 2,480 MW Ravenswood Facility in NYC.

Assisted Allegheny Electric Cooperative to identify power purchase and equity investment opportunities in PJM; evaluated economics and risk parameters of PPA, tolling, market purchases, and ownership options; reviewed ISDA and EEI agreements.

Part of the Procurement Monitor team for PURA to oversee Connecticut Light & Power and United Illuminating 2006-2012 supply procurements; responsible for credit issues and financial barrier options to protect against unanticipated price movements.

Advised LIPA on commercial and financial issues associated with multiple solicitations for on-island and off-island capacity and energy; refined contract terms on risk and credit.

Evaluated third party contracts, on-site generation alternatives for Visy Paper, NYC.

Evaluated design-build proposals for a CHP plant at Rochester Institute of Technology, including engineering / construction qualifications, O&M strategy, financial structure, utility interconnection issues, and lifecycle cost / ROI results.

Evaluated strategic electric and gas procurement strategy options for the Buffalo Fiscal Stability Authority; made procurement recommendations to BFSA and City officials.

Evaluated bidders for Indianapolis Power & Light's 1992 competitive power solicitation.

PROJECT FINANCING

Developed capital structure and cost of capital values for a MISO coal plant divestiture; evaluated depreciation assumptions and alternative (replacement cost less depreciation and comparable sale) valuations in support of state commission testimony.

Advised multiple clients on off-balance sheet financing structures, including tax-exempt operating leases and third-party ownership of CHP and cogen facilities.

Advised clients and conducted studies of merchant gas turbine and combined cycle financing assumptions filed at state commissions and FERC.

Structured non-recourse construction and permanent debt financing for Ocean State Power, the first domestic IPP; liaison between investors and financial advisor.

Developed off-balance sheet financing plans for ThermoElectron cogen projects.

Applied to the US Synthetic Fuels Corporation for price supports and loan guarantees.

Managed Pacific Gas and Electric's $60 million pollution control Industrial Development Bond financing for Geysers dry steam geothermal power plants; structured financing terms with bond counsel, investment banks, and corporate staff.

Recommended financing and contract support structures for Pacific Gas and Electric subsidiaries & joint venture projects, including coal mine, power plants, gas production, and residential conservation.

PRIVATIZATION & DIVESTITURE

Prepared comprehensive descriptions of Southern California Edison thermal generation (12 plants, 10,000 MW) and Commonwealth Edison coal stations (6 plants, 6,000 MW) for Divestiture Offering Memorandum.

Technical and economic advisor to Maine Public Service, Fitchburg Gas and Electric, and Unitil Corp for hydro, thermal, and power purchase agreement divestiture.

Commercial and contract advice to Empressa Electrica de Guatemala, S.A. for power plant divestiture.

Commercial advice (including forward pricing) to a confidential bidder for the New England Electric System divestiture (2800 MW thermal & 1200 MW hydro).

Provided technical / environmental advice to the Government of Pakistan for the 1600 MW Kot Addu plant privatization; developed capacity / energy contract pricing structure adopted in final sales documents.

GAS & FUEL PROJECTS

Developed integrated gas supply, storage, and forward haul transportation project for utilities in metropolitan New York / New Jersey to expand winter deliveries.

Evaluated equity return / risk profiles and prepared cash flow forecasts of interstate gas pipelines and storage projects for independent power plants in the Northeast.

Prepared testimony on risk, financing, and capital cost for the Endicott Pipeline Co.

Evaluated throughput and rate impacts on financial returns of competing gas pipeline proposals to support the development of Iroquois Gas Pipeline.

Commercial Advisor to the Pakistan Government for privatization of the Sui Northern Gas Pipeline Company (approx. 200 bcf annual sales with 24,000 km of pipe).

Determined distribution links between major domestic gas production basins and markets to allocate exploration and development funds of Sohio Petroleum.

World Bank advisor for Asia Pacific Ltd. oil storage & pipeline projects, Pakistan.

ENERGY & POWER PLANT OPTIMIZATION

Evaluated contract terms and conditions governing energy options for Nassau County Hub commercial district including cogeneration, spot market purchases, etc.

Assisted NYC industrial firm with cogeneration development; drafting steam purchase, power purchase option, site lease, and development contracts.

Developed cost-effective energy strategy with asset reconfiguration, contract restructuring, and permit modifications for Massachusetts Water Resources Authority.

Implemented direct gas service via Algonquin Gas Transmission and evaluated cogeneration options for Phelps Dodge copper plant in Connecticut.

Developed inside-the-fence cogeneration and fuel strategy for Arizona paper mill.

Identified optimal cogeneration plant configuration and fuel supply for City of Holyoke municipal utility.

FINANCIAL ANALYSIS & VALUATION

Evaluating proposed spin-off of Entergy transmission assets and merger with ITC Holdings for the Mississippi Public Service Commission, including capital structure, rate of return, business risk, transmission planning, MISO regulation, and rate issues.

Financial and business evaluation of proposed electrical distribution / cogeneration system in Brooklyn NY using innovative non-synchronous interconnection technology.

Assessed gas turbine market dynamics, commercial issues, and financial damages for lawsuit regarding turbine inlet fogging systems for enhancing output and efficiency.

Evaluated intended financing plan and resulting credit strength of proposed new owner of Entergy's merchant nuclear plants, including Vermont Yankee, for the Vermont DPS; prepared information requests and rebuttal testimony.

Prepared cogen investment analysis for Massachusetts Institute of Technology.

Co-authored fair market value appraisals of five 22 MW GWF Bay Area fluidized bed coke-fired power projects and the 209 MW Kalaeloa oil-fired cogeneration plant in support of financing transactions.

Advised lessor on buyout offer of wood-fired plant including future residual value.

Quantified the financial implications of purchasing an undivided equity interest in the River Bend nuclear plant in light of revised operating & maintenance expenses, revised administrative & general expenses, and changing market conditions for PECO Energy.

Evaluated pro forma assumptions and risk / returns of Malaysian power projects.

Reviewed financial feasibility of clean coal demonstration projects for DOE.

Managed steam purchase contract evaluation and internal cogeneration feasibility study for petrochemical producer in The Netherlands.

Proposed project financing options for Elektrenai plant modernization in Lithuania.

Power and fuel negotiation support for Cumbria Power, Ltd., the first English IPP.

Developed economic assumptions, financial pro formas, and equity return / risk profiles for numerous proposed power projects for ThermoElectron and clients.

Prepared long-term financial and rate forecasts of Pacific Gas & Electric for state commission filing.

GENERATION PLANNING / RESOURCE ECONOMICS

Audited Florida Power & Light's resource plan, including fuel, load, and generation.

Techno-economic cogeneration feasibility study for Algonquin Gas Transmission.

Valued existing generating plant based on alternative peaking capacity for Delmarva Power & Light.

Forecasted avoided energy / capacity costs for domestic third-party generators.

Supervised life cycle power plant economic analysis for a Fuel Use Act application.

Compared historic and projected electric use by manufacturing industry for EPRI.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Submitted Testimony and testified on behalf of the Vermont DPS addressing the reliability, market price, socio-economic, and environmental impacts of Vermont Yankee's potential retirement to the Vermont Public Service Board (Docket No. 7862).

Provided expert witness report on the gas turbine power market and turbine inlet cooling competition in legal malpractice suit concerning inlet fogging systems in the Ninth Judicial Court, Orange County, Florida (Case No. 2011-CA-004008-O).

Submitted expert report on alternative resource options, system reliability, market price, and socio-economic impacts of Vermont Yankee's potential retirement for the Vermont DPS in US District Court, District of Vermont (Civil Action No. 11-cv-99).

Submitted Affidavit to FERC on NYISO Demand Curve Reset parameters (excess capacity, system deliverability upgrades, and cost escalation rate) for Capability Years 2011/12 - 2013/14 on behalf of NYC generators (Docket ER11-2224-0000).

Provided Testimony on Deepwater Block Island offshore wind farm PPA price and electric impacts for the Rhode Island Economic Development Corporation, plus an Advisory Opinion on regional economic impacts, to the Rhode Island Public Utility Commission (Docket No. 4185).

Testified before the Virginia State Corporation Commission on behalf of Shell Energy NA regarding DVP's 2009 Integrated Resource Plan (Case No. PUE-2009-00096).

Submitted expert report and testified before the Virginia State Corporation Commission on behalf of Shell Energy NA regarding Dominion Virginia Power's 2007

Solicitation for 2011 Unit Capacity on RFP structure and bid evaluation issues (Case PUE-2008-00014).

Prepared information requests, submitted expert testimony, and testified before the Vermont Public Service Board on behalf of the Vermont DPS re: the proposed restructuring of Entergy's merchant nuclear generation assets (Docket No. 7404).

Submitted expert report on behalf of generator group; participated in FERC Technical Conference on proposed Reliability Pricing Model mechanism to set PJM market capacity prices (FERC Dockets Nos. EL05-148 and ER05-1410).

Prepared expert report on New York and New England capacity market mechanisms and plant valuation impacts for the Mirant Corporation Equity Committee in US Bankruptcy Court (Case No. 03-46590).

Submitted FERC affidavit regarding gas turbine engineering and economic parameters to reset locational ICAP demand curve; represented NYISO at FERC Technical Conference (FERC Docket No. ER05-428).

Expert witness regarding Salton Sea binary cycle geothermal EPC contract performance and consequential damages based on plant production and market power rates before the American Arbitration Association.

Expert witness testimony for the Bridgeport RESCO waste-to-energy facility at the Connecticut PURA re avoided cost pricing in the deregulated energy market (Docket 99-03-35REO3).

Tax valuation support for gas and electric assets for Yankee Gas Company and The Connecticut Light and Power Company in Connecticut Superior Court (Docket No. CV 95-0072561S).

Expert witness report supporting PECO Energy (Exelon) decision to cancel purchase of equity interest in the River Bend nuclear plant in US District Court for the Middle District of Louisiana (Adversary Proceeding No. 98-477-B-M3).

Expert witness report and testified regarding contractual benefits of major coal plant turbine upgrade for Mechanical Plant Services, Inc. based on future market power values in US District Court for the Middle District of Florida, Orlando Division, (Case No. 6:99-CV-76-ORL-22A); accepted as an expert in power project cost analysis and power price forecasting.

Expert witness regarding economic feasibility, financing, and profitability of Mid-Atlantic Energy's proposed cogeneration plant in West Virginia Circuit Court (Civil Action No. 95-C-214M).

Presented testimony on the relationship of independent power development fees to project capital costs before the American Arbitration Association.

PRESENTATIONS & PUBLICATIONS

Co-authored article "Working Jointly to Develop Offshore Wind" on socio-economic benefits and coordinating offshore wind development policies, published in North American Windpower, October 2012.

Speaker on cross-industry panel: "Let's Talk Transmission: Unplugged!" at the NARUC 2012 Summer Committee Meetings, July 2012.

Primary author of "Green Gridworks" lead article on transmission integration of renewable resources, Public Utilities Fortnightly, February 2012.

Panelist at the Northeast Offshore Wind Summit addressing renewable resource penetration and outlook in the ISO-NE electricity market, 2010.

Presentation to NYISO Installed Capacity Working Group on peaker proxy technology / cost / performance, deliverability, site requirements, availability, etc, 2010.

Moderated panel on ISO-NE's Forward Capacity Market mechanism at the Northeast Energy & Commerce Association's 2009 Power Markets Conference.

Gas and electric market interdependency panel moderator at Platt's 4th Annual Northeast Power Forum, 2009.

Sponsor for the Northeast Energy and Commerce and Association conference "Northeast Capacity Markets"; moderator for panel on generation entry / attrition outlook, 2007.

Conference organizer and moderator for "Capacity Markets – Impacts on Assets and Power Pricing" regarding generation and transmission investment in ISO-NE, NYISO, and PJM, 2007.

Conducted workshop, "Forecasting Capacity Prices in the Northeast" and panel moderator on generation financing at Infocast Northeast Power Supply Forum, 2006.

"Financing Projects with ICAP Revenues", Infocast Power Financing conference, 2004.

Panel moderator on "New England and Canadian LNG Projects", Infocast Atlantic Coast LNG Conference, 2004.

Speaker, "Power Sales Contract Restructuring Issues", at Infocast Asset Optimization and Portfolio Management Conference, 2003.

Panelist on "Southwest Connecticut Congestion", 10th Annual New England Energy Conference, 2003.

"Fuel and Power Contracting", Int'l District Energy Association Conference, 2002.

"Contract Restructuring", Infocast QF & IPP conference, 2001.

"Successful Valuation and Value-Creation of Transmission Assets", Infocast Electric Asset & Portfolio Valuation conferences, 2001.

"Evaluation of Repowering the Cabot Street Steam Station" using gas turbine technology, International District Energy Association conference, 2001.

"Plant Repowering" at the Infocast Plant Acquisition conference, 2000.

"Equipment Performance Impacts", Infocast Merchant Peaking Plant conference, 2000.

"The Pros and Cons of Repowering" in Competitive Utility, 2000.

"The First Wave" (initial divestiture results) 1998 and "Gas versus Coal" (techno-economic study) 1995, Independent Energy magazine.

"Evaluating Technical and Construction Risk" and "The Due Diligence Process", classes and case studies on for the Infocast Project Finance Institute, 1996-1998.

Non-utility generation and project financing classes at Stone & Webster Utility Management Development Program, 1989-96; General Electric, 1991-94; IBM 1994.

"Self Generation under Competitive Bidding", 1989 Cogen & IPP Congress.

EDUCATION

International Gas Turbine Institute course
Basic Gas Turbine Technology, 1996

Kennedy School (Harvard University) courses
International Political Economy, 1993
International Geopolitics of Oil, 1982

Wharton Graduate School (Univ. of Pennsylvania)
MBA in Finance / Operation Research, 1978

Brown University
Sc.B. in Applied Mathematics / Economics, 1976

MISCELLANEOUS

Member of the Newton Solid Waste Commission, 2011-

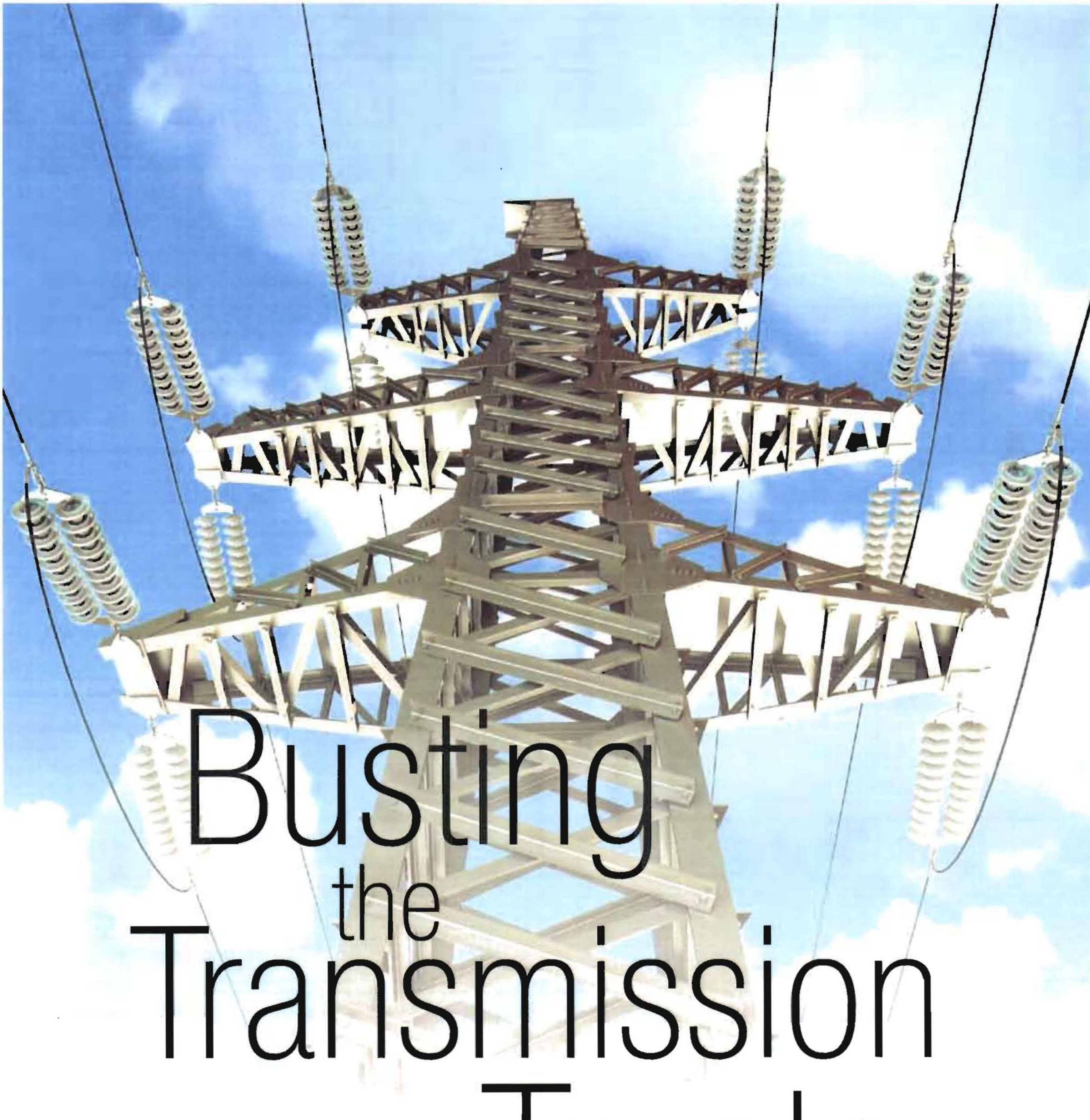
Board of Directors, Northeast Energy and Commerce Association, 2007-2011.

President and volunteer, Watertown Recycling Center; served on Watertown Trash and Recycling Committee that initiated curbside pickup 1990-1996.

Adjunct faculty lecturer in finance, Golden Gate University, 1979-1980.

Optimum yield resource management, National Oceanic and Atmospheric Administration, 1977.

Member of Mayor's Waterfront Development Committee and Interface: Providence urban design team, 1974-1976.



Busting the Transmission Trusts

EXHIBIT
tabbles
SGP-2

Creative destruction is coming, and it can't be stopped.

BY EDWARD N. KRAPELS

Over the next 20 years, the shape of our power grid will change—radically, in fact, as current indications suggest that federal regulatory reforms soon will give broader and clearer authority to state governments to influence what gets built.

And this restructuring will matter greatly, affecting both resources and risk.

On the resource side, over the last 100 years, we built a grid that enabled coal to generate half of our electricity—more than that in the heartland, less in the West Coast and Northeast regions. Likewise, the grid pattern of tomorrow will decide whether and how we get power from oil, coal, gas, hydro, nuclear, wind, or solar energy sources.

But the risk-reward equation will change even more. The reforms now planned will make the transmission industry much more competitive—though still regulated. But more important, the changes ahead will allow a much broader set of investors to participate in the opportunity to earn regulated, but attractive financial returns—the sort of revenue stream that hitherto has been largely reserved for the utility sector. In spite of all the resistance—and thanks largely to federal regulators—the United States is engaged in the kind of creative destruction of an oligarchical business that has been the hallmark of its long-term economic vitality.

Welcome to the Machine

The U.S. power grid is a complex machine, and it can be changed only via an intense and obscure political and regulatory process.

Up to about 1990, the grid was essentially run by regional oligarchies of large and small utilities, some overseen by state regulators, others co-opting state regulators. Since 1990, the federal government has tried to open the grid up to new participants: independent transmission companies. Then, starting in 2010, the federal regulators opened the grid further by taking away some of the ROFRs (rights of first refusal) to build transmission that the incumbent utilities have had for decades. This reform was aimed at encouraging not just small independents, but also large utilities—who could now move out from their native-load regions to compete with incumbent utilities in other regions in the difficult business of developing and building new transmission.

These changes are profound, and they will affect the pattern of electricity production in the United States. Natural gas plants will displace much of the old coal-fired system, and, in the states that care about climate change, renewable energy—wind and solar—will complement natural gas as the base sources of power. These are good changes: gas is cheap, it pollutes less than coal; and renewables are becoming cheaper, and they're emission-free. The transformation of the U.S. power sector, enabled by transmission reform, will add to economic growth and vitality, and will lay the foundation for a higher-tech, 21st-century grid.

Many of the changes in the grid are still to come. The incumbent regional electricity oligarchs are fighting and will continue to fight the process, but in the long run they will lose. The United States is one of the few countries that continuously disproves the "iron law of oligarchy."[1] As it transforms its grid, the United States will once again show that it's willing to blow up uncompetitive business structures in pursuit of progress, as it has done in a series of trust-busting initiatives that started under Theodore Roosevelt 110 years ago, and including the astounding destruction of the telephone monopoly in the 1990s. This courageous and historic propensity is taking aim at the electric transmission business. These breathtaking acts of political and regulatory creative destruction have had dramatic and positive effects on the nation over the years. As Daron Acemoglu and James A. Robinson write in their seminal work, *Why Nations Fail:* "[W]hile economic institutions are critical for determining whether a country is poor or prosperous, it is politics and political institutions that determine what economic institutions a country has. Ultimately, the good economic institutions of the United States resulted from the political institutions..." *(p.43).*

FERC Order 1000 will become the electric sector equivalent of the Glass-Steagall Act.

The grid is an economic institution of foundational importance to the American economy, and as such has always fallen prey to efforts by oligarchs to capture it. Because of its importance, it should be governed by political institutions. By its very nature, it is an interconnected meta-machine over which electrical commerce amounting to hundreds of billions of dollars per year is conducted. It knits the United States into three large networks—West, East, and Texas. Such a huge network breeds

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1. Originally formulated by Robert Michels, a German-Italian sociologist (1876-1936), as cited in Daron Acemoglu and James A. Robinson in *Why Nations*

oligarchies as naturally as railroads and telephony did in earlier periods of American history. And those oligarchies adopt (using *Why Nations Fail* terminology) "extractive behaviors"—attitudes of entitlement to society's surplus and corresponding rules from their allies in the political sphere—that are the bane of economic growth and dynamism.

History shows it's never easy for political institutions to put an end to such wealth-extracting practices. But one of the long-term and enduring distinctions of the United States has been the willingness of its political institutions ultimately to enforce competition on its oligarchical industries. To take but one timely example, the U.S. enactment in the 1930s of the Glass-Steagall Act smashed the financial oligarchy in 1933. The removal of that act in 1998 was a short-lived victory for a new breed of financial oligarchs, but they themselves undermined it by their reckless behavior in the 2000s. The enactment of the Dodd-Frank Wall Street Reform Act of 2010 is another manifestation of the admirable American tendency to bring oligarchs back to heel.

Now, it's time for the electric transmission sector to go through this all-American process.

The Meaning of Order 1000

The bold regulatory change that will become the equivalent of the Glass-Steagall Act of electricity is FERC Order 1000, which among other things is intended to allow state governments to make changes in the grid in pursuit of state public policy objectives. While Order 1000 has a number of targets, it aims primarily at two issues of particular importance to the argument being developed here. First, it's aimed at making transmission development easier for states to direct, which is important for the development of renewable energy in particular. Since a federal renewable policy hasn't emerged, and since not all states want to pursue large-scale renewables aggressively, Order 1000 provides a mechanism for developing the grid in the pursuit of state policy goals. Second, it's aimed at opening up the grid for transmission development competition by removing some of the preferential treatment that incumbent utilities have enjoyed for decades, in the form of ROFRs.

The federal government has long claimed jurisdiction over the grid because it's the conduit for interstate commerce in electricity. Federal jurisdiction has coexisted uneasily with a lack of federal involvement in paying for the grid. Essentially, state-regulated electricity utilities (and their consumers) paid for the grid, but FERC claimed jurisdiction over it. While there are federal electricity transmission domains, mostly in the West, there's never been a national electricity plan, in which the federal government decided how to build out the grid and then paid for it. If there had been such a plan, we might have a coast-to-coast electricity superhighway by now, similar to the interstate highway system that was built in the 1950s and 1960s. Instead, we have a grid essentially built out from the cities by electricity's oligarchs.

Under Order 1000, state law or a combination of laws from multiple states can direct transmission development. Depending on how a state operates, it can compel or incentivize companies to build out the grid for any state policy purpose, whether it's to connect renewables, or stimulate state economic development, or get access to cheap energy generated elsewhere. For example, Vermont and northern New York share a huge common border, and lots of commerce and movement along that border, yet practically no electric trade. One wonders why. Part of the answer is that the electricity system is a product of transmission decisions made over the decades, and no one decided to build a robust connection between Vermont and New York. The one line operating today, a 115-kV uncontrolled AC tie, was built decades ago. Even a cursory glance at the map would indicate that a high voltage connection between Burlington and Plattsburg, N.Y., across or under Lake Champlain, would provide a valuable anchor for both states' electric infrastructure. To provide steady energy and electric capacity from New York to Vermont, a new line with control technology should be built.

Another reason a large New York-to-Vermont connection was never built is that electric transmission development in the United States is a peculiar business. New York and New England are historically different control areas, and planning processes between the two electric regions have never been coordinated. Utilities have state charters, not multi-state charters, so it would've been presumptuous for Vermont utilities to ask too much of New York, and vice versa. Only in the late 1990s, when federal regulators began pushing for open access to interstate transmission lines and more electric commerce, did new development companies begin to view seams such as the one between New York and Vermont as business opportunities, rather than insuperable regulatory obstacles and hassles. With Order 1000, Vermont and New York, separately or together, could enable transmission companies to build a better transmission line simply because it was deemed consistent with the policies of either state, or both of them.

The oligarchs will continue to fight, but in the long run they will lose.

In a business where transmission decisions were made within a relatively closed system by an oligarchy, this is a big change indeed.

Selecting Future Projects

Given these changes to FERC regulations, how might these reformed transmission development rules be put into practice? Consider Vermont's neighbor, Massachusetts. Surveys of Massachusetts voters have consistently shown that the public supports renewable energy. The existing New England grid can't provide access to enough renewables to meet the commitment to renewables passed by the Massachusetts legislature—*i.e.,* the Green Communities Act of 2008 (GCA). Thanks to the GCA, enacted in Gov. Deval Patrick's first term, the Bay State has a large and expanding sustainable and clean tech energy sector. Its universities are providing the intellectual horsepower, its financial entrepreneurs are providing the seed capital, and the state government is providing the legislative and regulatory framework within which clean and sustainable energy can continue to thrive. But transmission constraints prevent large-scale renewables—mostly located in Maine, New Hampshire, New York, eastern Canada, and offshore sites—from reaching the market.

Legislation enacted in 2012 seeks to take advantage of the changes in FERC Order 1000, and begins the push for implementing a more progressive transmission development system where the importance of building out the grid is recognized as integral to meeting state RPS policy goals. It would allow the state to procure renewable energy and energy efficiency technologies on a large scale, including the price of transmission, in order to bring down the per-MWh cost. Solar and efficiency projects are implemented at a local level, but it's the implementation of hundreds of local projects—not few dozen—that will bring the unit cost down. Similarly, wind energy is extremely attractive: once built, it's completely removed from the vicious cycles of oil and gas prices. But the capital cost per unit will be much lower if obtained from large wind farms.

To get these economies of scale, the legislation envisions a more efficient procurement mechanism. Initially, the state relied on single electric utilities, each of which would contract for a small amount of wind energy. The larger the scale, however, the harder it is for utilities to be the agents of procurement, because in Massachusetts—as in other states where the traditional electricity oligarchies have been reformed—utilities no longer have all the customers. The new law provides a better way: it has utilities pool their RPS demand to allow for larger scale procurement. In addition, the law established a process under which the Commonwealth will determine a mechanism to pool state-wide demand through procurement of renewables into a single "customer."

With that, the costs of renewable energy and energy efficiency must be allocated to all the consumers equally in the electric sector so that one electricity customer—including traditional utility and competitive retail supplier customers—doesn't pay more than another to satisfy a state-wide public policy goal. Before 2012, these costs were allocated only to those who happened to be the customers of the utilities who had contracts for renewables and efficiency technology. That wasn't fair. Sustainability and environmental quality are common goods, and all residents benefited. Under the new law, investments through long-term commitments to purchase wind and solar energy will be shared by all who want to buy electricity off the grid.

Finally and perhaps most critically for the present argument, the right to build the transmission infrastructure needed to bring these renewables to market should be subject to a competitive process. In the spirit of FERC Order 1000, these kinds of transmission projects, secured by commitments from electric ratepayers via regulatory mechanisms, shouldn't necessarily go to incumbent utilities. Independent companies, or utilities from other jurisdictions, often can do it cheaper, better, smarter. Competition will push the process to get the best equipment vendors, the best developers, and the most efficient investors to come to the opportunity. In essence, in transmission, competition ultimately will be a better system than oligarchy, and has a much better chance to bring down the price of renewable energy.

The Massachusetts legislation, in other words, will put FERC Order 1000 into practice; a large scale and efficient procurement, coupled with a competitive process for selecting the best transmission project, will assure that the state remains the best in class in the development of a vibrant and competitive renewable energy sector.

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Enter the Pension Funds

FERC Order 1000 and progressive, pro-competitive legislation such as that emerging in Massachusetts provide the basis for a different financing model for transmission, a model that can drive the cost of transmission and renewables down. In this evolving landscape, pension funds, insurance companies, and other institutional investors will become direct owners of a greater portion of America's infrastructure. With that change, transmission is transformed from the extractive industry it is today, to an inclusive and competitive industry.

But why should direct investment by institutional investors, especially pension funds and insurance companies, be seen as a good thing? Because they have the capital to invest, they need long-term, predictable returns to pay their pension and insurance benefits, and with their investment the breadth of stakeholders in our electric infrastructure will be greater than ever.

In recent years, America's institutional investors have shown signs they are gearing up for leaner years ahead. Endowments, foundations, and pension, insurance, and sovereign wealth funds appreciate more than ever that—for many of them—the days of consistent double-digit returns in conventional investment classes are over. While believing the asset bubbles of the 2000s were the norm, slightly older veterans know that we can have a decade or more of low returns in conventional equity markets. Indeed, looking ahead, turmoil in the sovereign and municipal bond markets suggests that even capital preservation might be a non-trivial task. In this environment, assured 7.5 percent returns—a frequently cited target number—will be very challenging indeed.

This is why investments in infrastructure—especially of the kind that has a credit-worthy contract behind it—are deemed so valuable. In the past 10 years, almost $100 billion has been invested in U.S. electric transmission development. Most has been financed by utilities, providing them with a safe 10 to 12 percent rate of return. Some is now project-financed; independent transmission companies compete in RFPs, and bid market-based tariffs that are designed to win a competitive procurement. In this emerging, competitive transmission sector, developers have to design project returns that are low enough so that capital costs keep the bids competitive, but high enough to satisfy the investment thresholds of the financiers and developers.

The beauty of transmission infrastructure assets is that they last for decades and, properly designed, can provide annuity-like returns for investors who would happily have some stable returns amidst the cocktail of up-and-downside risk, volatility, and potential loss of principal found in the typical equity investment these days. Indeed, the recent portfolio descriptions of a lot of institutional investors commonly complain that "infrastructure" and "hard assets" are under-represented and notoriously difficult to find.

The fit between infrastructure projects that need investors, and investors who need infrastructure-type investments, should be obvious. In the coming decades, there will continue to be an urgent need for infrastructure investment in the United States and abroad. Electricity infrastructure assets, thus far, are mostly in the hands of utilities. Thus, an institutional investor seeking infrastructure exposure in that industry could, until recently, only buy utility stock. The problem with that is utility management might, or might not, be content to be an infrastructure play. Utilities in search of growth buy or merge with others. Investors and regulators have become increasingly skeptical about the benefits to the public from these ventures, and they are making M&A more difficult to execute.[2]

This is why recent developments in electric infrastructure finance are so intriguing. Slowly but surely, a transmission asset class is emerging that institutional investors can buy directly, with little or no danger of utility management surprises. Four major independent transmission projects have been developed, and one transmission company has been set up as a real estate investment trust (REIT). The independent transmission projects are: Neptune Regional Transmission System (New Jersey to Long Island); the Hudson Transmission Project (New Jersey to Manhattan); the Trans Bay Cable (Pittsburg, Calif., to San Francisco); and the Cross Sound Cable (Connecticut to Long Island). Interestingly, they are all direct current (DC) projects, and all are subsea. Collectively, they total almost $3 billion of capital invested. The equity has come from pioneering private equity firms, while the debt has been eagerly subscribed by institutional investors—notably, public and private institutions, and Taft-Hartley pension plans and insurance companies.

In all these cases, the initial development was carried out by a new breed of developers, some of them from the oil and gas business, others from the power plant development boom of the 1990s. After the first few projects paved the way, early development capital began to flow from U.S.-based private equity firms into projects, in large part because the private equity (PE) firms saw how attractive the electric power transmission asset class was to their limited partners. In exchange for the capital for early development, the PE firms obtained the right to buy equity and influence the placement of debt in the projects.

In transmission, competition will be a better system than oligarchy, and has a much better chance to bring down the price of renewable energy.

The Force of Financial Gravity

That brings us to the current period, 2013 through 2020. Looking ahead to the next $100 billion of infrastructure opportunities in the U.S. electric transmission sector, the question is: who will command the opportunities? The utilities, of course, will get their share, even though federal and some state regulators are trying to bring some competition into the sector. Assuming $50 billion or so is available to the competitive, project-finance market, who will get to invest the $15 billion or so of equity, and the $35 billion or so of debt, in the next Neptune and Hudson-like projects? A similar set of questions applies to the rest of the world, where the investment potential is multiples of the U.S. opportunity.

For transmission developers, the investment terrain is promising. There are mountains of capital wanting to be deployed by institutional investors. There should be competition between transmission developers, and those that can directly access investor capital at competitive rates will thrive, because their lower

2. For example, see "S&P Cuts Duke Energy, Citing Abrupt Leadership Changes," *Wall Street Journal*, July 25, 2012. "The ratings firm said as a result of the sudden leadership shift, the company may not be able to realize

arena at a lower cost of money. Moreover, companies representing institutional investors willing to buy and hold will have an advantage over those who need to flip the asset a few years into projects' commercial operation. Cross Sound Cable and Neptune interests have already been sold in secondary markets, and the buyers were firms that had comparatively low cost of capital.[3] For institutional investors, transmission projects are prized assets; they're long lasting, low maintenance, and critical to their customers, and they typically have a material residual value at the end of the initial financing period.

Moreover, transmission projects can be liquid assets. In the long run, after the transmission projects are built, many of them will wind up in REITs. In a private letter ruling issued in 2007, the U.S. Internal Revenue Service ruled that electric power transmission assets qualify as "real property" and can therefore be held in REITs.[4] Just as master limited partnerships are good institutional homes for oil and gas pipelines, REITs are good homes for electric transmission lines.

The biggest challenge for institutional investors is financing project development risk. At the moment, the mosaic of state transmission rules make investment in new transmission a risky proposition. FERC Order 1000 will do a lot to diminish that risk, which in turn should give new transmission projects access to low-cost capital. Since the demand for new, competitively developed transmission projects will increase, and there's abundant capital wanting to be deployed in this asset class, institutional investors will simply have to become accustomed to investing some early development capital. In the competition to be awarded new transmission projects over the next 10 years, the cost of capital will matter, and institutional investors will have to shift their focus from allocating transmission capital from traditional fund vehicles toward more direct and larger infrastructure development vehicles.

It seems inevitable that the force of financial gravity—institutional investors seeking infrastructure's long-term stable returns and infrastructure's seeking stable, long-term investors—ultimately will exert itself. But it isn't easy to replace an oligarchical system as deeply embedded as we have in transmission. FERC's Order 1000, the intensity of the desire of state governments to control their own electric energy destinies (in the absence of federal leadership), and financial gravity are going to change the enormous machines called the transmission grid of the United States—and enable natural gas and renewables to step in where

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3. Most recently, Calpers, the Califoria retirement fund, acquired a majority interest in the Neptune project in 2013.
4. Sharyland Utilities, L.P. was the party requesting the private letter ruling. Subsequently, Sharyland created a REIT that includes as participants Hunt Transmission (a Sharyland affiliate), along with John Hancock, TIAA-CREF,