Exhibit TC-10

UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

	)	
TransConnect, LLC	)	Docket No. ER-01-___-000
	)	

DIRECT TESTIMONY OF WILLIAM E. AVERA

ON BEHALF OF TRANSCONNECT, LLC

FINCAP, Inc.
3907 Red River
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November 2001

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I. INTRODUCTION

Q. Please state your name and business address.

A. William E. Avera, 3907 Red River, Austin, Texas, 78751.

Q. In what capacity are you employed?

A. I am a financial, economic, and policy consultant to business and government.

A. Qualifications

Q. What are your qualifications?

A. I received a B.A. degree with a major in economics from Emory University. After serving in the U.S. Navy, I entered the doctoral program in economics at the University of North Carolina at Chapel Hill. Upon receiving my Ph.D., I joined the faculty at the University of North Carolina and taught finance in the Graduate School of Business. I subsequently accepted a position at the University of Texas at Austin where I taught courses in financial management and investment analysis. I then went to work for International Paper Company in New York City as Manager of Financial Education, a position in which I had responsibility for all corporate education programs in finance, accounting, and economics.

In 1977, I joined the staff of the Public Utility Commission of Texas (PUCT) as Director of the Economic Research Division. During my tenure at the PUCT, I managed a division responsible for financial analysis, cost allocation and rate design, economic and financial research, and data processing systems, and I testified in cases on a variety of financial and economic issues. Since leaving the PUCT in 1979, I have been engaged as a consultant. I have participated in a wide range of assignments involving utility-related matters on behalf of utilities, industrial customers, municipalities, and regulatory commissions. I have previously testified before the Federal Energy Regulatory Commission (FERC or the Commission), as well as the Federal Communications Commission (FCC), the Surface Transportation Board (and its predecessor, the Interstate Commerce Commission), the Canadian Radio-Television and Telecommunications Commission, and regulatory agencies, courts, and legislative committees in 28 states.

With the approval of then–Governor George W. Bush, I was appointed by the PUCT to the Synchronous Interconnection Committee to advise the Texas legislature on the costs and benefits of connecting Texas to the national electric transmission grid. Currently, I am serving as an outside director of Georgia System Operations Corporation, the system operations arm of the nation's largest member-owned supplier of electricity.

I have served as Lecturer in the Finance Department at the University of Texas at Austin and taught in the evening graduate program at St. Edward's University for twenty years. In addition, I have lectured on economic and regulatory topics in programs sponsored by universities and industry groups. For the last 20 years I have taught in hundreds of educational programs for financial analysts in programs sponsored by the Association for Investment Management and Research, the Financial Analysts Review, and local financial analysts societies. These programs have been presented in Asia, Europe, and North America, including the Financial Analysts Seminar at Northwestern University. I hold the Chartered Financial Analyst (CFA) designation and have served as Vice President for Membership of the Financial Management Association. I have also served on the Board of Directors of the North Carolina Society of Financial Analysts. I was elected Vice Chairman of the National Association of Regulatory Commissioners (NARUC) Subcommittee on Economics and appointed to NARUC's Technical Subcommittee on the National Energy Act. I have also served as an officer of various other professional organizations and societies. A resume containing the details of my experience and qualifications is attached as Appendix A.

B. Overview

Q. What is the purpose of your testimony?

A. TransConnect, LLC (TransConnect) is requesting a 14.5 percent return on equity (ROE) in this case. The purpose of my testimony is to develop an independent estimate of the fair rate of return on equity range for TransConnect and demonstrate that the requested 14.5 percent ROE is reasonable when combined with a capital structure consisting of 50 percent common equity and 50 percent long-term debt.

Q. Please summarize the basis of your knowledge and conclusions concerning the issues to which you are testifying in this hearing.

A. To prepare my testimony, I used information from a variety of sources that would normally be relied upon by a person in my capacity. I am familiar with the mission and proposed organization, finances, and operations of TransConnect from reviewing numerous documents submitted in its application, along with past regulatory orders, including the Commission's Order on Regional Transmission Organizations (Order 2000)[1] and decisions of state commissions. I obtained information relevant to the present filing through discussions with TransConnect's member management and reviewed various financial forecasts and related documents. I also reviewed information relating generally to capital markets and specifically to investor perceptions, requirements, and expectations for regulated utilities in a restructured electric power market. These sources, coupled with my experience in the fields of finance and utility regulation, have given me a working knowledge of ROE issues affecting TransConnect and are the basis of my conclusions.

Q. What is the role of the return on equity in setting a utility's rates?

A. The rate of return on common equity compensates shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors commit capital only if they expect to earn a return on their investment commensurate with returns available from alternative investments with comparable risks. To be consistent with

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[1] *Regional Transmission Organizations*, Order No. 2000, December 20, 1999, 89 FERC φ 61,285.

sound regulatory economics and the standards set forth by the Supreme Court in the *Bluefield*[2] and *Hope*[3] cases, a utility's allowed return on common equity should be sufficient to (1) fairly compensate capital invested in the utility, (2) enable the utility to offer a return adequate to attract new capital on reasonable terms, and (3) maintain the utility's financial integrity.

Q. How did you go about developing a fair rate of return on equity range for TransConnect?

A. I first reviewed the anticipated operations and finances of TransConnect as an independent electric transmission company and the general conditions in the electric utility industry and the economy. With this background, I developed the principles underlying the cost of equity concept and then conducted various quantitative analyses to estimate the cost of equity for three groups of reference utilities. These included the discounted cash flow (DCF) methodologies currently prescribed by this Commission applied to reference groups of natural gas transmission companies and electric utilities, as well as DCF cost of equity estimates for the firms in the *S&P 500* index and checks of reasonableness based on alternative risk-premium analyses.

From the cost of equity estimates indicated by my DCF analyses, a fair rate of return on equity range for TransConnect was selected taking into account the economic requirements of an independent transmission company capable of meeting the goals of the Commission's Order 2000. I also analyzed capital market evidence on two factors properly considered in setting a fair rate of return in this case: the relatively small size and significant financing requirements of TransConnect. These factors are crucial to evaluating TransConnect's required rate of return on equity because they demonstrably increase investors' required returns. In addition, regulators seldom encounter a utility in a start-up phase that must maintain access to capital markets without the benefit of an established operating history. This Commission's policy of encouraging the development

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[2] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.W. 679 (1923).

[3] *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

of independent transmission organizations that can fund urgently needed capital investment in new facilities and facilitate effective wholesale competition offers enormous benefits to consumers. At the same time, investors must be offered the opportunity to earn an adequate return on equity if the potential payoffs in greater reliability, access to cheaper power, and the development of competitive markets are to be realized.

C. Summary and Conclusions

Q. What is your recommended rate of return on equity range for TransConnect?

A. Based on my analysis, I recommend that TransConnect be authorized a rate of return on equity in a range between 12.0 and 15.5 percent. This recommendation falls within the range of DCF results for the groups of natural gas transmission companies and electric utilities produced by the Commission's DCF models. While TransConnect's requested return on equity of 14.5 percent exceeds the midpoint of this range, it properly considers the additional risks associated with its relatively small size when compared with the reference groups of natural gas pipelines and electric utilities. These groups consist of relatively large, existing companies having diversified activities and operating in established markets. On the other hand, TransConnect will be a newly formed company with no track record entering a restructured industry without established business practices. In addition, TransConnect will be required to raise substantial amounts of external capital to fund its projected capital expenditures. Investors may perceive additional risks associated with financing these spending requirements and TransConnect will also incur additional costs associated with "floating" additional common equity. Finally, as discussed in the testimony of Ms. Carolyn J. Cowan, TransConnect faces other unique uncertainties that would be considered in the rate of return required by investors. Besides being required to compensate shareholders for the greater risks of a restructured electric industry, a return of this magnitude is necessary to ensure investor confidence and attract capital investment in transmission facilities so urgently needed for reliability and the development of a competitive electricity market in the Northwest.

II. FUNDAMENTAL ANALYSES

Q. What is the purpose of this section?

A. This section examines the risks and prospects for the electric utility industry and conditions in the capital markets and the general economy. An understanding of these fundamental economic factors affecting utilities is essential to developing an informed opinion about the investor expectations and requirements that form the basis of a fair rate of return on equity. In addition, as a predicate to my economic and capital market analyses, this section briefly reviews the formation of TransConnect and its projected operations and finances.

A. TransConnect, LLC

Q. Briefly describe TransConnect.

A. Currently in the organizational stage, TransConnect will be formed as a for-profit independent transmission company responsible for owning, operating, and building transmission facilities in the Northwest, including areas in the states of Montana, Idaho, Washington, Oregon, and Nevada. The interstate transmission facilities that will form TransConnect are being combined from five electric utilities – Avista Corporation, Montana Power Company, Nevada Power Company (Nevada), Portland General Electric Company (Portland), and Sierra Pacific Power Company (Sierra). Certain member of TransConnect, namely, Nevada, Portland, and Sierra (Applicants), are sponsoring this rate filing in an effort to respond to the various requirements and incentives in Order 2000. The non-Applicant Members (Avista Corporation and Montana Power Company) will be TransConnect members but are not currently seeking the various transmission rates and policies proposed in this filing.

TransConnect Corporate Manager, Inc. (Corporate Manager) will be formed as a separate company to serve as the managing member of TransConnect and will have control over its policies and procedures. Corporate Manager is authorized to issue three classes of common stock and at formation will be the sole holder of Class A common stock, which conveys full voting rights. Member utilities that elect to transfer their ownership interest in TransConnect into stock will receive Class B common stock, which has limited voting rights.[4] An additional class of stock with full voting rights (Class C) is reserved for non-market participants. TransConnect will operate as a single transmission entity within the larger structure of a regional transmission organization (RTO). Currently, TransConnect is proposing to participate in the formation of RTO West.

Q. How will TransConnect be financed?

A. In addition to granting ownership interests for contributed transmission assets, TransConnect will also repay the debt allocable to these assets. This debt repayment will be financed through new debt issued in the capital markets. TransConnect will be solely responsible for this new debt, without backing from the region's utilities. Prospectively, TransConnect plans to raise additional capital directly or through the Corporate Manager by selling fixed income securities in the capital markets and issuing additional equity, either privately or through an Initial Public Offering (IPO) of the common stock of the Corporate Manager. TransConnect may also request that its members and other parties provide funding for working capital and certain improvements and expansions. Fulfilling any such request, however, is completely at the option of the members or other participants. TransConnect has targeted a capital structure consisting of approximately 50 percent equity and 50 percent debt. It is anticipated that TransConnect's debt will be rated low investment grade. It is also estimated that over the next approximately five years, the Applicants will have capital expenditure requirements totalling some $690.7 million. The purpose of this investment is to upgrade the transmission infrastructure in the Northwest to correct constraints and transfer limitations.

B. Electric Power Industry

Q. What are the general conditions in the electric power industry?

A. For almost twenty years, lower fuel costs, inflation, and interest rates have provided electric utilities and their consumers a respite from the rapidly escalating electricity prices

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[4] The ownership interest is established in proportion to the value of the member's transmission system to the aggregate value of the transmission system transferred by all members.

of the late 1970s and early 1980s. More recently, however, these general economic factors have been overshadowed by structural changes in the electric utility industry resulting from market forces, decontrol initiatives, and judicial decisions.

Q. Please describe these structural changes.

A. Competition is being increasingly promoted at the federal and state levels. The National Energy Policy Act of 1992, which reformed the Public Utility Holding Company Act of 1935, greatly increased prospective competition for the production and sale of power at the wholesale level. In April 1996 this Commission adopted Order No. 888, which mandated open access to the wholesale transmission facilities of jurisdictional electric utilities, and it more recently addressed improvements to the transmission system including the establishment of RTOs in Order 2000.

While wholesale wheeling provides transmission-dependent electric utilities with additional energy supply options, it has also introduced new risks to participants in the wholesale power markets. As Moody's Investors Service (*Moody's*) recognized:

> Companies throughout the natural gas and electric power sectors face an uncertain future as the utility industry undergoes restructuring and moves toward increased competition. The changes, in large part, stem from the efforts of the Federal Energy Regulatory Commission (FERC) that have introduced a greater measure of competition into the natural gas and electric power wholesale markets during the 1990s. Similar efforts underway or anticipated at the state level are already altering the fundamentals of the manner in which energy is bought and sold and moved to the retail customer.[5]

Policies affecting competition in the electric power industry vary widely at the state level, but over 25 jurisdictions have enacted some form of industry restructuring. As foreshadowed by Merrill Lynch in 1996, this process of industry transition has led to the disaggregating of many formerly integrated electric utilities into three primary components – generation, transmission, and distribution:

[5] Moody's Investors Service, *Special Comment*, p. 5 (April 1999).

> The electric utility industry is in a monumental transition state at the current time. The transition is from a vertically integrated, monopoly industry to one that we expect to be very competitive and significantly restructured. We expect all utility customers to have competitive choices in the next 5-10 years. We expect companies to realign and/or disaggregate their businesses – some may exit the generation business, others may exit the distribution business –as well as well as merge to create larger companies. ...The risk profile of the electric utility industry is clearly reaching higher levels than it has experienced in the past and will further increase.[6]

More recently, however, industry restructuring received a setback when electricity prices in California (one of the first states to implement competition) skyrocketed.

Q. What impact have events in California and the Western U.S. had on investors' risk perceptions for firms involved in the electric power industry?

A. In the mid-1990s, California saw itself ready to claim the forefront of utility deregulation; now, inadequate power supplies, rising demand, and a failed market structure have combined to produce a well-publicized energy crisis. *S&P* summarized the fallout from the California crisis in the fall of 2000:

> Persistent hot weather, a dearth of needed new generation capacity, rapid customer growth and usage, record natural gas prices and the consequent explosion in power prices to double and even triple normal prices in an extremely short time, are wreaking political havoc for state and federal officials. There has been a great deal of finger pointing and anger generated by the frustrated expectations for lower prices that competing generation suppliers would provide. Some argue that generators are holding back supply to take advantage of the extremely volatile and lucrative energy markets. Others contend that there simply is not enough energy to meet California's increasing electricity demands. Reduced import capabilities, due to strong economic and load growth both in the Northwest and Southwest, have also limited generation alternatives.

[6] Merrill Lynch, *Electric Utilities Industry Report*, p. 3 (June 24, 1996).

> While it is inevitable that electricity demand in California will exceed supply for the foreseeable future, California is still in a desperate search for an immediate fix to its pricing crisis.[7]

Besides causing regulators and legislators to re-evaluate their industry restructuring plans, the financial implications of the recent California experience have exposed the hidden risks facing all segments of the electric power industry. The massive debts owed by the state's utilities to banks, power producers, and other creditors have shattered their financial integrity. Earlier this year, investors watched bond ratings for the two largest utilities in the state drop from investment grade to "junk" status within a matter of weeks. The subsequent bankruptcy filing of Pacific Gas and Electric Company (PG&E) in April brought the uncertainties associated with today's power markets into sharp focus for the investment community. *S&P* commented on the continuing difficulties faced by investors caught up in the debacle:

> Indeed, since last summer, the company and its investors have experienced nothing but frustration – first with respect to stemming the drain of its financial resources by the malfunctioning wholesale power market before these resources finally ran dry and then with its attempts to recover these resources. As Chairman Glynn commented last Friday, the regulatory and political processes have failed us. On Monday, Standard & Poor's took one of the final downward rating actions remaining to be taken on PG&E. We downgraded the utilities senior unsecured debt rating to 'D' from 'CC' in light of the company's comments that it did not anticipate paying regularly scheduled interest on these obligations.[8]

While the case of PG&E represents an extreme example, there is every indication that investors' risk perceptions for electric utilities have shifted sharply upward as events in the Western U.S. have continued to unfold.[9]

[7] Standard & Poor's, "The Calm in the Storm: California's Municipal Electric Utilities", *RatingsDirect* (September 28, 2000).

[8] Standard & Poor's, "California Utilities Update", *RatingsDirect* (April 16, 2001).

[9] For example, Platts' *Electric Utility Week* (July 9, 2001) noted that the "crisis saps investor confidence" and that fallout from the financial deterioration of California's utilities had spread beyond the state as "investors have turned away, spooked by the political and regulatory climate".

Q. What risks are associated with the transmission segment of the industry?

A. Transmission operations are becoming increasingly complex, as Standard & Poor's Corporation (*S&P*) observed:

> As overall power loading continues to grow with deregulation and as the power quality demands of a digital society increase, managing this system, especially the delivery function, will become more difficult. [10]

S&P also recognized that existing transmission systems were not designed to accommodate competitive markets and large-scale power transfers:

> The principal operational challenges facing RTOs and ISOs will be the advancement of reliable operations and reasonable prices as these organizations manage large volumes of electricity transmission transactions derived from numerous sources.[11]

These challenges posed by an increasingly complex marketplace heighten the uncertainties associated with transmission operations while requiring the commitment of significant new capital investment to maintain and enhance service capabilities.

And even though the transmission segment of the industry is expected to remain largely regulated, government oversight does not entirely shield transmission activities from competitive risks. Transmission operations will face competitive pressures because electricity competes with other fuels (e.g., natural gas) in certain market segments. As noted by *S&P*, customers building their own generating capacity typically do not require the transmission grid to any great extent:

> The potential widespread installation of smaller, more efficient generation equipment on customer sites could reduce the value not only of central generation, but also the distribution and transmission assets. This may lead to potential stranded assets for "the wires" business at some future date.[12]

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[10] Standard & Poor's, "The Growing Vulnerability of the U.S. Power Grid", *Utilities & Perspectives*, p. 1 (Nov. 8, 1999).

[11] Standard & Poor's, "Electric Transmission Organizations Are Experiencing Growing Pains", *Utilities & Perspectives*, p. 2 (December 11, 2000).

[12] Standard & Poor's, "Distributed Generation Creeps Into the T&D World", *Utilities & Perspectives*, p. 2 (November 27, 2000).

S&P pointed out the risk of bypass in an industry review two years ago:

> Some customers may choose to leave the service territory or, as generation technologies advance, the economics of the new machines may drive some customers to pursue options such as microgenerators, and forgo back-up power from the utility. Recovering "exit fees" from such customers may be difficult. As a result, the utility could lose these customers not only as generation customers, but as distribution (or wires) customers as well.[13]

Similarly, ongoing technological advances that increase the feasibility and economic viability of other alternatives to incumbent electric service providers, such as fuel cells, also exacerbate these competitive uncertainties, a concern to investors recognized by *S&P*:

> Eventually, alternative energy-related technologies, most notably fuel cells, microturbines, and microgrids, may significantly alter the way energy is procured and transported. Some technologies may be able to provide energy without using at least a portion of the electric system, whether generation, transportation, or distribution, while other technologies will provide a reliable back-up power source.[14]

The results of a survey of electric customers indicated that approximately 43 to 49 percent of commercial customers believed that on-site generation could compete with the incumbent electric distribution utility.[15] Similarly, a recent survey of state regulators in 46 jurisdictions conducted on behalf of *S&P* found that commissions favor the rapid introduction of off-grid distributed generation technology by an overwhelming 9-1 margin.[16]

Transmission utilities remain exposed to economic vagaries within their service territories that cause service revenues and costs to fluctuate.[17] For example, a prolonged

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[13] Standard & Poor's, *Global Sector Review: Utilities*, p. 21 (Nov. 1998).

[14] Standard & Poor's, "Nonregulated Investments Continue To Affect Utility Strategies", *Utilities & Perspectives*, p. 2 (December 4, 2000).

[15] Standard & Poor's, *CreditWeek*, p. 21 (Oct. 6, 1999).

[16] RKS Research & Consulting, "Second Thoughts? Utility Regulators Express Growing Concern About Energy Deregulation", *Press Release*, p. 2 (May 2, 2001).

[17] While formula rates may mitigate some of the risk of cost and revenue fluctuations, they do not eliminate the effects of underlying economic changes on the transmission utility's service area.

economic downturn would likely stall demand for transmission service and lead to revenue shortfalls. Because transmission utilities are characterized by relatively high fixed costs and attendant operating leverage, the impact of revenue losses on operating earnings is further magnified. Finally, a transmission utility continues to face other risks associated with operating a utility system, including the impact of adverse weather and extraordinary risks such as legal liabilities and natural disasters.[18]

Q. Is the transmission segment facing additional risks because of industry restructuring?

A. Yes. As a regulated, incumbent provider of transmission service, TransConnect will be obligated to ensure the stability and integrity of the transmission system for the ultimate benefit of electricity consumers. At the same time, TransConnect remains exposed to the difficulties of obtaining the permits and capital required to build new facilities. As *S&P* observed, transmission capacity has not kept up with load growth:

> Traditionally, utilities would be adding new transmission capacity to handle the expected load increase. However, because of the difficulty in obtaining permits and the uncertainty over obtaining adequate rate of return on investment, the total of transmission circuit miles added yearly is declining while total demand for transmission resources continues to grow.[19]

S&P went on to note in a December 2000 article that:

> The formation of independent system operators (ISO) and regional transmission organizations (RTO) that comply with the FERC directive has created capital needs that require debt financing. The credit quality of these debt obligations hinges on the ability of transmission organizations to recoup debt service through charges associated with the grid's management.[20]

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[18] For example, a catastrophic natural disaster could impose such a heavy burden of unanticipated costs on a transmission utility and its customers that formula rates could not buffer the total economic impact.

[19] Standard & Poor's, "The Growing Vulnerability of the U.S. Power Grid", *Utilities & Perspectives*, p. 1 (Nov. 8, 1999).

[20] Standard & Poor's, "Electric Transmission Organizations Are Experiencing Growing Pains", *Utilities & Perspectives*, p. 2 (December 11, 2000).

Thus, the confluence of past circumstances and a redesign of the transmission infrastructure to accommodate a restructured electric industry are requiring a substantial investment in new transmission facilities, resulting in additional risks associated with attracting adequate capital.

For transmission assets, these risks are compounded by their immobility. Once installed, transmission facilities are not readily re-deployable elsewhere if local economic conditions or other circumstances reduce the demand for transmission services in their area. By contrast, thanks to Orders 888 and 889, generating assets can access new markets if the local market turns unfavorable. Indeed, while a reliable and capable transmission grid is a prerequisite to flexibility in the deployment of generation, investment in transmission does not enjoy the same advantage.

Additionally, beyond the inherent uncertainties associated with operating in an entirely new market structure, the creation of new entities to own and operate the transmission grid entails its own risks. For example, in its rationale for assigning a triple-B debt rating to the Midwest Independent Transmission System Operator, Inc. (MISO), Duff & Phelps Credit Rating Co. (DCR) noted the significance of MISO's lack of operating history:

> As a new enterprise, the MISO is untested. It may incur costs exceeding its plan, or systems issues may delay the targeted start-up date. Either scenario would extend the cost recovery period to a later date, effectively back-ending the cash flow necessary to service this debt.[21]

DCR's concerns appear to be born out given the significant uncertainties that have surrounded the organization and development of RTOs.

Q. Are all of the risks associated with the restructuring of the electric industry known at this time?

A. No. Experience with deregulation in the transportation and natural gas industries demonstrates that the structural changes associated with deregulation produce

[21] Duff & Phelps Credit Rating Company, *New Financing Report*, p. 1 (May 2000).

consequences that no one can predict. In particular, as prices for electricity become primarily market-driven, future changes in prices – and therefore the demand for transmission service – become inherently uncertain. Much of this uncertainty simply reflects the superior ability of markets to adjust continually both to changing customer needs and to changing costs of meeting those needs. This point was succinctly stated in the *Economic Report of the President*:

> An insufficiently appreciated property of markets is their ability to collect and distribute information on costs and benefits in a way that enables buyers and sellers to make effective, responsive decisions. ... As tastes, technology, and resource availability change, market prices will change in corresponding ways, to direct resources to the newly valued ends and away from obsolete means. It is simply impossible for governments to duplicate and utilize the massive amount of information exchanged and acted upon daily by the millions of participants in the marketplace.[22]

In short, while a restructured electric power industry is expected to provide benefits for both producers and consumers, these benefits come at a cost. Namely, all participants will become exposed to considerably greater risks than they faced under a fully regulated market, many of which cannot even be anticipated at this early juncture.

C. Economy and Capital Markets

Q. What has been the pattern of interest rates during the 1980s and 1990s?

A. Average long-term public utility bond rates, the monthly average prime rate, and inflation as measured by the consumer price index since 1979 are plotted in the graph below. After peaking at 16.89 percent in September 1981, the average yield on long-term public utility bonds generally fell through 1986, reaching 8.77 percent in January 1987. Yields remained at or above 10 percent through mid 1989, gradually declined to 7 percent in October 1993, but then rose to 9 percent in November 1994. Interest rates then began a general decline, with the average public utility bond yield being 7.73 percent in September 2001:

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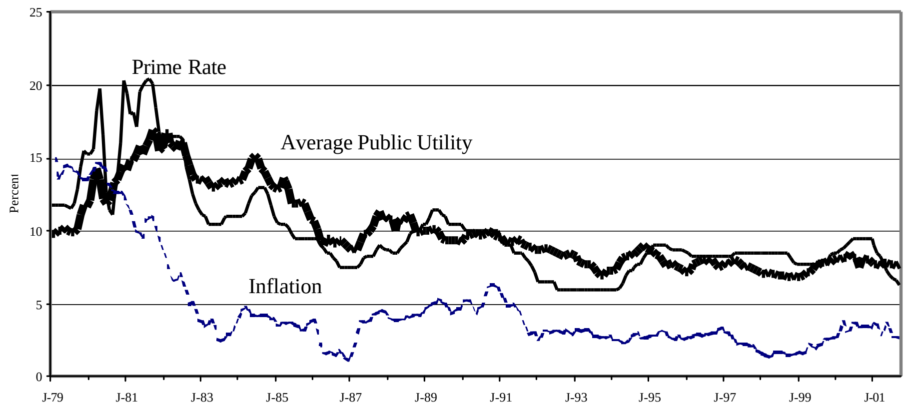
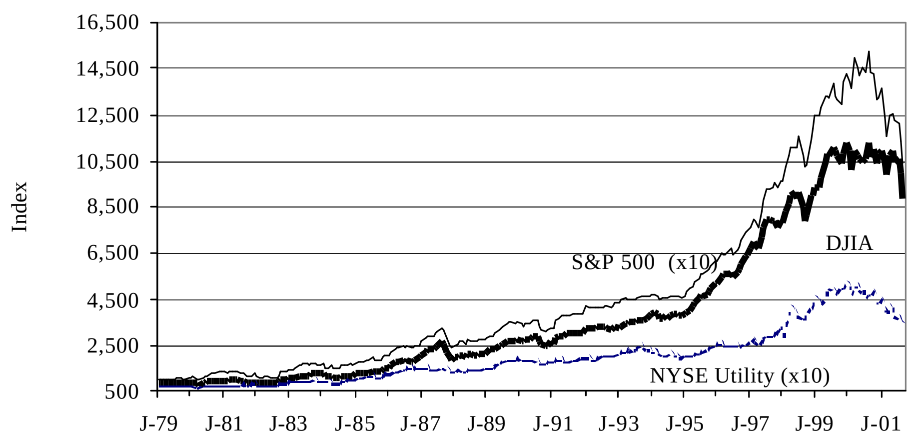
[22] ECONOMIC REPORT OF THE PRESIDENT, p. 191 (1997).



Q. How has the market for common equity capital performed over this same period?

A. The past 20 years have witnessed the longest bull market in U.S. history, which is generally attributed to low inflation and interest rates, sustained economic growth, a favorable business climate, and widespread merger and acquisition activity. While common stocks have increased over ten times in value since 1979, valuations, particularly for firms in high technology industries, have fallen considerably since the first quarter of 2000. At the same time, the market has become increasingly volatile, with share prices repeatedly changing in full percentage points during a single day's trading. The graph below plots the performances of the Dow-Jones Industrial Average, the *S&P* 500 Composite Index (*S&P 500*), and New York Stock Exchange Utility Index since 1979 (the latter two indices were scaled for comparability):



Although the general trend in stock prices obscures much of the daily and weekly volatility in the graph, these short-term swings have increased risks for participants in equity markets. As noted in The Value Line Investment Survey (*Value Line)*, investors have also felt these uncertainties in once-stable utility stocks:

> Utility investors have had to endure much more stock volatility than usual for the industry during the past three months. At the start of this year, the Dow Jones utility index fell some 19% from the December 2000 peak.[23]

Q. What is the outlook for the U.S. economy and capital markets?

A. During the past decade, the U.S. economy has enjoyed the longest peacetime expansion in history. Monetary and fiscal policies resulted in modest inflation during this period, with unemployment rates falling to their lowest levels since the 1960s. A revolution in information technology, rising productivity, and vibrant international trade have all contributed to strong economic growth. However, even before the events of September 11, 2001, there were increasing signs that the economic expansion would not be sustainable. Concerns regarding the slowing pace of economic activity were exemplified by the Federal Reserve's sequential lowering of interest rates. Uncertainties over the fragility of the economy have only been magnified in the aftermath of the recent terrorist attacks, which threaten to further undermine consumer confidence and contribute to global economic instability. These factors cause the outlook to remain tenuous, with persistent stock and bond price volatility providing tangible evidence of the uncertainties faced by the U.S. economy.

Q. How do these capital market uncertainties affect electric transmission companies?

A. For electric transmission companies, higher inflation would place pressure on the adequacy of service rates, while stalled economic growth would undoubtedly affect the level of transmission activity. Although the economic expansion may resume in 2002, conflicting economic indicators, including volatile natural gas prices that particularly affect new generation, cause considerable uncertainties to persist. Additionally, the

[23] Value Line Investment Survey, *Electric Utility (East) Industry*, p. 155 (March 9, 2001).

volatility of stock and bond prices creates significant financial risks as electric transmission companies must raise enormous amounts of capital to finance required transmission plant additions.

III. CAPITAL MARKET ESTIMATES

Q. What is the purpose of this section?

A. In this section, capital market estimates of the cost of equity are developed for benchmark groups of utilities and competitive firms. First, I examine the concept of the cost of equity, along with the risk-return tradeoff principle that is fundamental to capital markets. Next, I describe alternative DCF analyses conducted to estimate the cost of equity for reference groups of gas transmission companies, electric utilities, and the *S&P 500*. Finally, I report the findings of risk premium analyses based on authorized and realized rates of return that served as a check on my DCF results.

A. Cost of Equity Concept

Q. What role does the return on common equity play in a utility's rates?

A. As noted earlier, the return on common equity serves to compensate shareholders for the use of their capital to finance the plant and equipment necessary to provide utility service. Investors are free to invest their funds wherever they choose, and they will commit money to a particular investment only if they expect it to produce a return commensurate with those from other investments with comparable risks. Competition for investor funds is intense, even for utilities.

Q. How is a fair rate of return on common equity determined?

A. Unlike debt capital, there is no contractually guaranteed return on common equity capital since shareholders are the residual owners of the utility. Nonetheless, common equity investors still require a return on their investment, with the cost of equity being the minimum "rent" that must be paid for the use of their money. This cost of equity typically serves as the starting point for determining a fair rate of return on common equity.

Q. What fundamental economic principle underlies this cost-of-equity concept?

A. The concept is predicated on the notion that investors are risk averse. In capital markets where relatively risk-free assets are available (*e.g.*, U.S. Treasury securities), investors can be induced to hold riskier assets only if they are offered a premium, or additional return, above the rate of return on a risk-free asset. Since all assets compete with each other for investor funds, riskier assets must yield a higher expected rate of return than safer assets to induce investors to hold them.

Given this risk-return tradeoff, the required rate of return (k) from an asset (i) can generally be expressed as

$$K_i = R_f + RP_i$$

where R_f = risk-free rate of return, and
RP_i = Risk premium required to hold riskier asset i.

Thus, the required rate of return for a particular asset at any time is a function of (1) the yield on risk-free assets and (2) its relative risk, with investors demanding correspondingly larger risk premiums for assets bearing greater risk.

Q. Is there evidence that the risk-return tradeoff principle actually operates in the capital markets?

A. Yes. The risk-return tradeoff can be readily documented in segments of the capital markets where required rates of return can be directly inferred from market data and where generally accepted measures of risk exist. Bond yields, for example, reflect investors' expected rates of return, and bond ratings measure the risk of individual bond issues. The observed yields on government securities and bonds of the various ratings categories demonstrate that the risk-return tradeoff does, in fact, exist in the capital markets.

To illustrate, the table below shows average yields during September 2001 on long-term U.S. government securities and on utility bonds of different ratings reported by

Moody's.[24] The data show that as risk (measured by progressively lower bond ratings) increases, the required rate of return rises. Also shown is the risk premium over long-term government securities for each bond rating category.

Bond and Rating	September 2000 Yield	Risk Premium Over Long-Term Treasury
U.S. Treasury		
Long-term	5.66%	*n.a.*
Public Utility		
Aaa	7.52%	1.86%
Aa	7.55%	1.89%
A	7.75%	2.09%
Baa	8.12%	2.46%

Q. Does the risk-return tradeoff observed with fixed income securities extend to common stocks and other assets?

A. It is generally accepted that the risk-return tradeoff evidenced with long-term debt extends to all assets. Documenting the risk-return tradeoff for assets other than fixed income securities, however, is complicated by two factors. First, there is no standard measure of risk applicable to all assets. Second, for most assets – including common stock – required rates of return cannot be directly observed. Yet there is every reason to believe that investors exhibit risk aversion in deciding whether or not to hold common stocks and other assets, just as when choosing among fixed-income securities.

Q. Is this risk-return tradeoff limited to differences between firms?

A. No. The risk-return tradeoff principle applies not only to investments in different firms, but also to different securities issued by the same firm. The securities issued by a utility vary considerably in risk because they have different characteristics and priorities. Long-term debt secured by a mortgage on property is senior among all capital in its claim on a utility's net revenues and is therefore the least risky. Following first mortgage bonds are other debt instruments also holding contractual claims on the utility's net revenues, such

[24] Moody's Investors Service, *Credit Market Trends Service*. Long-term Treasury bond yield average for July 2000.

as debentures. The last investors in line are common shareholders. They receive only the net revenues, if any, that remain after all other claimants have been paid. As a result, the rate of return that investors require from a utility's common stock, the most junior and riskiest of its securities, must be considerably higher than the yield offered by the utility's senior, long-term debt.

Q. What does the above discussion imply with respect to estimating the cost of equity?

A. Although the cost of equity cannot be observed directly, it is a function of the returns available from other investment alternatives and the risks to which the equity capital is exposed. Because it is unobservable, the cost of equity for a particular utility must be estimated by analyzing information about capital market conditions generally, assessing the relative risks of the company specifically, and employing various quantitative methods that focus on investors' required rates of return. These various quantitative methods typically attempt to infer investors' required rates of return from stock prices, interest rates, or other capital market data.

Q. What additional difficulties are associated with estimating current costs of equity in the electric power industry?

A. Estimating the cost of equity is difficult, even when comparable publicly traded companies are available. The ongoing restructuring of the electric power industry exacerbates the problems. Industry participants are in the midst of realigning their businesses, with many electric companies disaggregating along functional lines while others are aggressively expanding and diversifying their operations. *Moody's* noted that, because of market restructuring, it has become increasingly difficult to identify a peer group of firms that are directly comparable:

> The diverse strategies adopted in response to the deregulation of the US market have moved the industry from a peer group of 121 vertically integrated, regulated electric utilities, to 121 peer groups of one.[25]

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[25] Moody's Investors Service, *Electric Utilities Industry Outlook*, p. 4 (October 2000).

In turn, this has only added to the complexities involved in benchmarking the cost of equity by reference to other publicly traded firms.

Q. Are there any problems in estimating TransConnect's cost of equity not usually encountered in the regulatory arena?

A. Yes. First, TransConnect is a startup company. It has no debt outstanding, and TransConnect's stock will initially be held by the entities that have contributed transmission facilities. Second, there will be no public market for the equity of TransConnect or Corporate Manager until an IPO is completed. Hence, there is no direct capital market evidence of how investors will assess the risk of TransConnect. And to make matters more difficult, there are no publicly traded independent transmissions companies with which to compare TransConnect.

Q. Did you rely on a single method to estimate the cost of equity for TransConnect?

A. No. Despite the theoretical appeal of and precedent for using a particular method to estimate the cost of equity, no single approach can be regarded as wholly reliable. As the FCC recognized:

> Equity prices are established in highly volatile and uncertain capital markets. ... Different forecasting methodologies compete with each other for eminence, only to be superseded by other methodologies as conditions change. ... In these circumstances, we should not restrict ourselves to one methodology, or even a series of methodologies, that would be applied mechanically. Instead, we conclude that we should adopt a more accommodating and flexible position.[26]

While this Commission has not similarly embraced all methodologies, it has a clear record of innovation in determining ROEs.[27] Accordingly, while I rely primarily on the

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[26] FCC, Report and Order 42-43 (CC Docket No. 92-133) (evaluating methods used to prescribe rates of return for telephone companies) (1995).

[27] In 1984, for example, FERC went through an extensive rulemaking to establish procedures for annually determining a benchmark rate of return for electric utilities [FERC Order No. 389, 49 Fed. Reg. 29946 (July 25, 1984)]. The procedures were in place for nearly eight years and were abandoned after they had accomplished the Commission's objectives [FERC Order No. 538, 57 Fed Reg. 802 (January 9, 1992)]. Similarly, when the Commission realized that investor expectations were no longer captured by the constant-growth DCF model, it implemented the two-stage model for natural gas pipelines [*Ozark Gas*

DCF models adopted by FERC, I also corroborate my DCF results by reference to risk premium analyses that focus specifically on electric utilities. In my opinion, comparing estimates produced by one method with those produced by other methods ensures that the estimates of the cost of equity pass fundamental tests of reasonableness and economic logic.

B. DCF Theory

Q. How are DCF models used to estimate the cost of equity?

A. DCF models have been customarily relied on to estimate the cost of equity in regulatory proceedings, including those at this Commission. This use of DCF models is essentially an attempt to replicate the market valuation process that sets the price investors are willing to pay for a share of a company's stock. The models rest on the assumption that investors evaluate the risks and expected rates of return from all securities in the capital markets. Given these expected rates of return, the price of each stock is adjusted by the market until investors are adequately compensated for the risks they bear. Therefore, we can look to the market to determine what investors believe a share of common stock is worth. By estimating the cash flows investors expect to receive from the stock in the way of future dividends and capital gains, we can calculate their required rate of return. In other words, the cash flows that investors expect from a stock are estimated, and given its current market price, we can "back-into" the cost of equity that investors presumptively used in bidding the stock to that price.

Transmission System, 68 FERC ¶ 61,084 (1998)]. The Commission has subsequently refined this model to stay abreast of changing capital market conditions [*Northwest Pipeline Corp.*, Opinion No. 396-B, 79 FERC ¶ 61,309, ¶62,379 (1997), *reh'g denied*; Opinion No. 396-C, 81 FERC ¶ 61,036 (1997); *Transcontinental Gas Pipeline Co*, Opinion No. 414-A, 84 FERC ¶ 61,084 (1998). For a discussion of the refinements to the two-stage model, see *Williston Basin Interstate Pipeline Co.*, 91 FERC ¶ 63,005 (2000)]. More recently, the Commission determined that the significant differences in the electric utility industry and the natural gas pipeline industry require different approaches to growth rates in DCF models [*Southern California Edison Co.*, FERC Opinion No. 445, 92 FERC ¶ 61,070 (2000) (*Southern California Edison*)].

Q. What market valuation process underlies DCF models?

A. DCF models are derived from a theory of valuation which posits that the price of a share of common stock is equal to the present value of the expected cash flows (*i.e.*, future dividends and stock price) that will be received while holding the stock, discounted at investors' required rate of return, or the cost of equity. Notationally, the general form of the DCF model is as follows:

$$P_0 = \frac{D_1}{(1+k_e)^1} + \frac{D_2}{(1+k_e)^2} + \cdots + \frac{D_t}{(1+k_e)^t} + \frac{P_t}{(1+k_e)^t}$$

where: P_0 = Current price per share,
P_t = Expected future price per share in period t,
D_t = Expected dividend per share in period t, and
k_e = Cost of equity.

That is, the cost of equity is the discount rate that will equate the current price of a share of stock with the present value of all expected cash flows from the stock.

Q. Has this general form of the DCF model customarily been used to estimate the cost of equity in rate cases?

A. No. In an effort to reduce the number of required estimates and computational difficulties, the general form of the DCF model has been simplified to a "constant-growth" form. This simple form of the model was once the predominant form used at FERC and other regulatory agencies. Converting the general form of the DCF model to the constant-growth DCF model requires making several strict assumptions. These include:

- A constant growth rate for both dividends and earnings,
- A stable dividend payout ratio,
- A discount rate greater than the growth rate,
- A constant growth rate for book value and price,
- A constant earned rate of return on book value,
- No sales of stock at a price above or below book value,
- A constant price-earnings ratio,
- A constant discount rate (*i.e.*, no changes in risk or interest rate levels and a flat yield curve), and
- Extending all of the above to infinity.

Given these assumptions, the general form of the DCF model can be automatically reduced to the more manageable formula of:

$$P_0 = \frac{D_1}{k_e - g}$$

where: g = Investor long-term growth expectations.

The cost of equity (k_e) can be isolated by rearranging terms:

$$k_e = \frac{D_1}{P_0 + g}$$

This constant-growth form of the DCF model recognizes that the rate of return to stockholders consists of two parts: (1) dividend yield (D_1/P_0) and (2) growth (g). In other words, investors expect to receive a portion of their total return in the form of current dividends and the remainder through price appreciation.

Q. Are the assumptions underlying the constant-growth form of the DCF model met in the real world?

A. In practice, none of the assumptions required to convert the general form of the DCF model to the constant-growth form are ever strictly met. In some instances, where earnings are derived solely from stable activities, and earnings, dividends, and book value track fairly closely, the constant-growth form of the DCF model may be a reasonable working approximation of stock valuation. However, in other cases, where the circumstances surrounding the firm severely violate the required assumptions, the constant-growth DCF model may produce widely divergent and meaningless results. This is especially true if a firm's earnings or dividends are unstable, or if investors expect the stock price to be affected by factors other than earnings and dividends.

Q. What is the alternative to the constant-growth model when companies are in transition and short-term growth differs from investors' long-term expectations?

A. This Commission and other regulatory agencies have recently employed a two-stage DCF model to conform to investors' expectations of changing growth rates. Instead of using a single, constant growth rate, the two-stage model combines shorter-term growth estimates with a longer-term growth rate.

C. Reference Groups

Q. Can quantitative methods be applied directly to estimate the cost of equity for TransConnect?

A. No, not at the present time. As described above, application of the DCF model to estimate the cost of equity requires and observable stock price. Because TransConnect currently has no publicly traded stock, its cost of equity cannot be estimated directly using the DCF model. As an alternative, the cost of equity for an untraded firm is often estimated by applying the DCF model to publicly traded companies engaged in the same business activity. However, because there are presently no other "pure play" publicly traded independent electric transmission companies, neither can the DCF model be applied in this way to estimate the cost of equity for TransConnect.

Q. Without stock prices for TransConnect or other independent electric transmission companies, how can the DCF model be used to estimate the cost of equity?

A. Because there are no publicly traded "pure play" electric transmission companies, it is necessary to identify other groups of publicly traded firms that are regarded by investors as having similar risks. The DCF model can be applied to these companies to estimate their cost of equity, which can then be adjusted upward or downward to reflect the relative investment risks of TransConnect.

Q. What groups of publicly traded firms does the investment community regard as having business risks similar to those of independent electric transmission companies?

A. As with the service provided by an electric transmission utility, most natural gas pipelines transmit gas from producers to a local distribution company service area. Although there are certainly differences in the risk of providing electric versus gas utility services, investors recognize many similarities. Both are open access common carriers regulated by this Commission, and neither is involved in the merchant function. In an article entitled "A New Breed of Utility: The ISO", *S&P* stated that it believes electric transmission companies will have investment risks similar to those of large gas pipelines:

> A transmission company will closely resemble a large interstate natural gas transportation company. [28]

The FERC staff has also recognized the increasing congruence between investors' risk perceptions for natural gas and electricity transmission activities. In Docket No. RP00-107-000 involving Williston Basin Interstate Pipeline Company, the staff proposed expanding the proxy group used to estimate the cost of equity for gas pipelines to include utilities with electric utility operations, noting that investors *see a linkage between the risk profile of different types of utilities*[29] and concluding that:

> (G)as pipelines and transmission facilities for electricity have characteristics in common in that both transmit a product with time and weather sensitive demand profiles over rights-of-way that are capital intensive and relatively inflexible. Expanding the gas pipeline proxy group to include publicly-owned companies engaged in other regulated lines of energy-related business will, in my opinion, increase the level of confidence in the reasonableness of the results of my DCF analysis…[30]

Meanwhile, much of the other investment literature discusses independent electric transmission companies in the context of the electric utility industry, but recognizes that the generation, transmission, and distribution segments will face differing risks as the industry is restructured. Thus, electric utilities also serve as a reference point for estimating the cost of equity for TransConnect. Finally, because TransConnect is a start-up entity, never before presented to investors as a "pure play" business, I also included the *S&P 500* as an additional benchmark. In my experience, when presented with untested companies, investors are likely to equate the risk to the market average, as represented by the *S&P 500*. Investors maintain this default position until experience enables them to assess specific risks. While arguments may be made that a new

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[28] Standard & Poor's, *CreditWeek*, p. 10 (May 31, 2000).

[29] Williston Basis Interstate Pipeline Company, Docket No. RP00-107-000, *Prepared Direct and Answering Testimony of Commission Staff Witness George M. Shriver, III*, p. 17 (June 7, 2000).

[30] *Ibid*.

investment might prove less risky than the market average, investors tend to reserve judgment until more of a track record has been established. Hence, the *S&P 500* is a benchmark that investors would consider in assessing their return requirements for an untested company like TransConnect.

D. Natural Gas Pipelines

Q. How did you go about estimating the cost of equity for natural gas transmission companies?

A. I applied the current two-step DCF methodology that has been adopted by this Commission to estimate the cost of equity for gas pipelines.[31]

Q. What companies did you included in your gas pipeline reference group?

A. I applied the DCF model to a group of seven natural gas pipeline companies included in the Natural Gas (Integrated) industry by *Value Line*.[32] In addition, I also examined results for the pipeline industry group typically used by the Commission to estimate the cost of equity for gas transmission companies. In the past, this group has consisted of Coastal Corporation (Coastal), El Paso Corporation (El Paso), Enron Corporation (Enron), PanEnergy Corp. (PanEnergy), Sonat, Inc. (Sonat) and The Williams Companies (Williams). However, Duke Energy has acquired PanEnergy, and Coastal and Sonat have been acquired by El Paso. Therefore, only three publicly traded pipeline companies remain – El Paso, Enron, and Williams.

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[31] The form of the model is consistent with the Commission's discussion in its recent order addressing this issue, *Transcontinental Gas Pipeline Corporation*, Order on Initial Decision, 90 FERC ¶ 61,279 (2000).

[32] With the exception of Coastal and Columbia, which were acquired by El Paso Corporation and NiSource, Inc., respectively, this group of natural gas companies was also relied on by the Administrative Law Judge in his May 9, 2001 Initial Decision in *Williston Basis Interstate Pipeline Company*, 95 FERC ¶ 63,008.

Q. How did you calculate the dividend yield component of the two-step DCF model for the gas transmission industry group?

A. Consistent with Commission policy, the dividend yield for each of the gas pipeline companies was calculated based on the average indicated dividend yield for the six months March through August 2001. This six-month average historical dividend yield (D_0/P_0) was then increased by one-half of the growth rate to convert it an adjusted dividend yield corresponding to the expected dividend yield (D_1/P_0) of the DCF model.

Q. How did you calculate the growth component of the two-step DCF model for the gas transmission reference group?

A. Under the Commission's two-step DCF model, the growth component of the DCF model (*g*) is calculated as a weighted average of investment analysts' short-term projected growth in earnings per share and long-term projected growth in U.S. Gross Domestic Product (GDP). Specifically, investment analysts' projected growth, which is weighted two-thirds, is the 5-year earnings growth forecast for each firm published by I/B/E/S International, Inc. (I/B/E/S). Meanwhile, growth in GDP, which is weighted one-third, is the simple average of the 20-year plus projections by DRI/McGraw Hill (DRI), Wharton Economic Forecasting Associates (WEFA), and the Energy Information Administration (EIA). These various growth rates are shown in columns (d) through (h) of Exhibit TC-11, with the weighted average growth rate for each gas pipeline company being shown in column (i).

Q. What cost of equity range does the Commission's two-step DCF model produce for this reference group of gas pipelines?

A. As shown in column (j) of Exhibit TC-11, individual cost of equity estimates for the firms in the reference group of natural pipelines ranged from 10.4 to 15.0 percent with a median of 14.1 percent. Turning to the three companies typically referenced by FERC, the Commission's DCF approach produced cost of equity estimates for a natural gas transmission company within a narrower range of 14.1 to 14.4 percent, with a median of 14.3 percent.

E. Electric Utilities

Q. How did you go about estimating the cost of equity for reference groups of electric utility companies?

A. I applied this Commission's current one-step DCF methodology that has been adopted to estimate the cost of equity for electric utilities.[33]

Q. What reference groups of electric utilities were included in your analyses?

A. The Commission's one-step DCF model was applied to those firms included by *Moody's* and *S&P* in their respective Electric Utilities groups and having and *S&P business profile* ranking of "4" or "5". Excluded from my analyses were companies engaged in a major merger or acquisition, which tends to distort certain financial data (*e.g.*, stock prices), firms that do not pay cash dividends, or those companies for which no I/B/E/S growth rate was currently available. These criteria resulted in the reference groups of electric utilities shown on Exhibits TC-12 and TC-13. On average, these two groups of electric utilities are rated single-A by both *Moody's* and *S&P*.

Q. How did you calculate the dividend yield component of the DCF model for the electric utility reference groups?

A. Again following Commission policy, average low and high indicated dividend yields were calculated for each electric utility during the six months March through August 2001. These six-month average low and high historical dividend yields were also increased by one-half of the low and high growth rates discussed subsequently to convert them to adjusted dividend yields.

Q. What growth rates are used in the Commission's one-step DCF method for electric utilities?

A. Whereas the Commission's two-step DCF method calculates a single growth rate for each gas pipeline, the Commission's one-step DCF method for electric utilities employs two

[33] *Southern California Edison Company*, 92 FERC ¶ 61,070 (2000).

growth rates for each firm. The first growth rate is a "sustainable" growth rate calculated by the following formula:

$$g = \mathrm{br} + \mathrm{sv}$$

where: b = expected retention ratio;
r = expected earned rate of return;
s = percent of common equity expected to be issued annually as new common stock;
v = equity accretion ratio.

The second growth rate is the consensus 5-year earnings growth forecast published by I/B/E/S. These two growth rates are combined with the adjusted dividend yields to develop a cost of equity range for each company.

Q. How did you calculate the sustainable growth rate of the one-step DCF model for the electric utility reference groups?

A. For each electric utility, the expected retention ratio (b) was calculated based on *Value Line's* projected 2004-2006 dividends and earnings per share. Likewise, each firm's expected earned rate of return (r) was computed by dividing projected earnings per share by projected 2004-2006 net book value. The percent of common equity expected to be issued annually as new common stock (v) was calculated using *Value Line's* projected changes in common shares outstanding between 2000 and 2004-2006, with the equity accretion ratio (v) being based on each firm's projected 2004-2006 market-to-book ratio. The resulting sustainable growth rate for each electric utility is shown in column (d) of Exhibits TC-12 and TC-13.

Q. What are investment analysts' projected growth rates for the companies in the electric utility reference groups?

A. The 5-year earnings growth forecasts published by I/B/E/S for each electric utility in the reference groups are shown in column (e) of Exhibit TC-12 and TC-13.

Q. What cost of equity range does the Commission's one-step DCF model produce for the *Moody's* reference group?

A. As shown in columns (f) and (g) of Exhibit TC-12, application of the Commission's one-step DCF model to the *Moody's* Electric Utilities group results in a range of reasonableness of 9.4 to 13.4 percent, with the midpoint being 11.4 percent.

Q. What zone of reasonableness is produced for the *S&P* Electric Utilities group?

A. For the *S&P* Electric Utilities, the individual cost of equity estimates implied by the FERC one-step DCF approach produced a zone of reasonableness of 9.2 to 18.1 percent (Exhibit TC-13), with the midpoint being 13.7 percent.

Q. What implications do the structural changes in the electric industry have for the security analysts' projections used in the Commission's one-step DCF model?

A. As discussed earlier, electric utilities are in the process of disaggregating and realigning their operations in response to industry restructuring. As a result, investors recognize that a large component of electric utilities' business will face risks and prospects akin to other firms in the competitive sector. *Value Line* corroborated the view that the expanding scope of electric utilities' operations implies higher expected growth:

> [Utilities] are currently building sizable electric generating and gas asset bases to compete effectively in the domestic energy trading market. Too, big companies have expanded investment in major foreign utilities. Other forays into areas such as energy management, independent power generation, oil and gas exploration, and telecommunication services are also moving ahead. *These operations will help utilities meet rising earnings expectations.*[34]

Similarly, in discussing the future growth prospects of Duke Energy, the company's chief risk officer noted that electric companies will offer investors the prospect of accelerated earnings growth to compensate for the additional risk that comes with being an energy merchant in competitive markets:

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[34] Value Line Investment Survey, *Survey and Opinion*, p. 157 (Dec. 11, 1998) (emphasis added).

> "The business profile is higher risk," says [Richard] Osborne, but with it comes the hope of future 12% to 14% annual profit growth, instead of the 8% to 10% growth that Duke is projecting to analysts these days.[35]

Technological changes are also expected to result in greater demand for power, as *Moody's* recognized:

> In addition to core economic growth, electric consumption has been fueled by the nation's increased use of computer related and electronic items. Clearly, more homes and more businesses actively use computer-related technology on a regular basis. With the advent and growth of the Internet, this trend is likely to continue to promote electric consumption growth that surpasses growth in the gross national product by a wide margin.[36]

Thus, while securities analysts' near-term growth projections for electric utilities have risen in response to industry restructuring, they are likely to understate investors' longer-term growth expectations for electric utilities as they enter the competitive phase of market development.

Q. How do the I/B/E/S growth estimates for electric utilities compare with comparable growth rates for firms in the competitive sector?

A. I/B/E/S estimates imply an average projected growth rate for the firms in the *S&P 500* over the next five years of 15.4 percent.[37] Despite the fact that analysts' growth projections for electric utilities have been trending higher as restructuring has progressed, they remain considerably below those for other firms in the competitive sector. Accordingly, near-term growth projections are likely to understate investors' growth expectations for electric utilities once the transition to competition is completed. One indication of the growth investors expect for competitive firms is the published I/B/E/S estimates for the firms in the *S&P 500*. The average of these growth rates is significantly higher than the utility growth projections, which suggests that the I/B/E/S utility growth rates – and the resulting cost-of-equity estimates – are understated.

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[35] Wysocki, Jr., Bernard, *Soft Landing or Hard? Firm Tests Strategy on 3 Views of Future*, WALL STREET JOURNAL at A1, A6 (July 7, 2000).

[36] Moody's Investors Service, *Electric Utilities Industry Outlook*, p. 9 (October 2000).

Q. Is there anything else occurring the electric power industry that might impact investors' growth expectations?

A. Yes. The prospect for continued mergers, acquisitions, and corporate spin-offs in the utility industry can distort the pricing mechanism presumed by the DCF model. As Value Line noted in a March 2001 report on CH Energy Group, Inc, the possibility of a merger can have a dramatic impact on a utility's stock price:

> **CH Energy stock is up nearly 10% since our last report**, three months ago. We attribute that to renewed takeover speculation, since CH Energy – the only electric company in the state that's not involved in merger and acquisition activity – is relatively small. We don't rule out such a possibility, especially if the company can't find attractive nonregulated companies for which is can use its cash hoard.[38]

Expectations of price appreciation that might be realized in the event of a merger, acquisition, or spin-off are not typically incorporated into the growth estimates used in the Commission's constant growth DCF model, but such growth is reflected in the share prices of electric utilities.

Q. Has FERC recognized that considerations such as industry restructuring are relevant in implementing the DCF model and interpreting the results?

A. Yes. In *Southern California Edison* the Commission explained that, in choosing the DCF growth rate for electric utilities, one should consider not only the pace of the current restructuring of the industry and changes in dividend policies, but also how the investment community analyzes companies in the industry.[39]

In this case, the above factors suggest that the two growth rates used in the Commission's one-step DCF model do not fully reflect investor expectations regarding the transition of the electric utility industry to competitive growth rates or the impact of

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[37] The 15.4 percent growth rate is the average of the individual estimates for the firms included in the *S&P 500* Index, as reported in *S&P's Earnings Guide* (August 2001).

[38] Value Line Investment Survey, p. 158, emphasis in original (March 9, 2001).

[39] 92 FERC ¶ 61,070, slip op. at 15-16.

merger activity. As a result, estimates of investors' actual growth expectations are biased downward, which leads to an understatement of the cost of equity.

Q. Are there any other DCF benchmarks that may be useful in assessing the cost of equity for TransConnect?

A. Yes. Since TransConnect will be a new company and there are no "pure play" firms that are directly comparable, another benchmark might be the *S&P 500*. This broad sample of stocks, which includes companies involved in most segments of the economy, is widely referenced by investors as a benchmark for return requirements in the absence of company-specific information. Combining the 15.4 percent projected I/B/E/S growth rate noted earlier with the current *S&P* dividend yield of 1.4 percent results in a cost of equity estimate of 16.8 percent.[40]

F. Risk Premium Analyses

Q. What other analyses did you conduct to estimate the cost of equity?

A. I also evaluated the cost of equity using risk premium methods. While I am aware that this Commission has relied primarily on the DCF methodology to estimate the cost of equity, it is my opinion that because the cost of equity is inherently unobservable, no single method should be considered a solely reliable guide to investors' required rate of return. My applications of the risk premium method employ alternative approaches to measure equity risk premiums, encompass several periods and sample groups of companies, and include data through the present. In deference to this Commission's previous decisions, I have used the risk premium method solely to corroborate the results of the DCF model.

Q. Briefly describe the risk premium method.

A. The risk premium method of estimating investors' required rate of return extends to common stocks the risk-return tradeoff observed with bonds. The cost of equity is

[40] *S&P 500* dividend yield from Standard & Poor's website at www.spglobal.com/indexmain500_data.html.

estimated by first determining the additional return investors require to forgo the relative safety of bonds and to bear the greater risks associated with common stock, and by then adding this equity risk premium to the current yield on bonds. Like the DCF model, the risk premium method is capital market oriented. However, unlike DCF models, which indirectly impute the cost of equity, risk premium methods directly estimate investors' required rate of return by adding an equity risk premium to observable bond yields.

Q. How did you implement the risk premium method?

A. The actual measurement of equity risk premiums is complicated by the inherently unobservable nature of the cost of equity. In other words, like the cost of equity itself and the growth component of the DCF model, equity risk premiums cannot be calculated precisely. Therefore, equity risk premiums must be estimated, with adjustments being required to reflect present capital market conditions and the relative risks of the groups being evaluated.

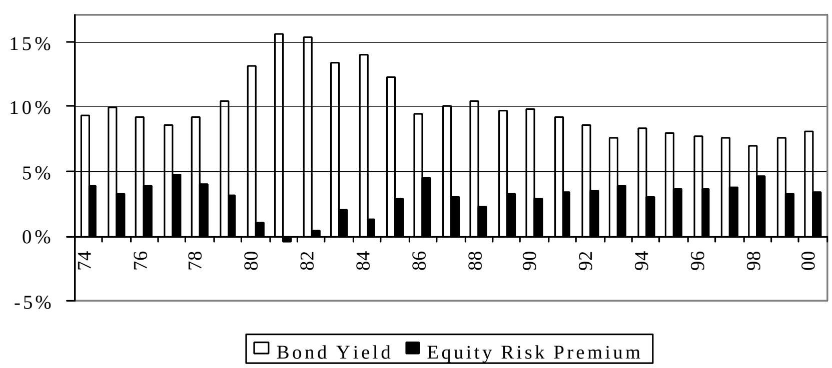
I based my estimates of equity risk premiums for electric utilities on (1) surveys of previously authorized rates of return on common equity, and (2) realized rates of return. Authorized returns presumably reflect regulatory commissions' best estimates of the cost of equity, however determined, at the time they issued their final order, and the returns provide a logical basis for estimating equity risk premiums. Under the realized-rate-of-return approach, equity risk premiums are calculated by measuring the rate of return (including dividends, interest, and capital gains and losses) actually realized on an investment in common stocks and bonds over historical periods. The realized rate of return on bonds is then subtracted from the return earned on common stocks to measure equity risk premiums.

Q. How did you implement the risk premium approach using surveys of allowed rates of return?

A. While the purest form of the survey approach would involve asking investors directly as to the additional return above interest rates they require to compensate for the additional risks of common equity, surveys of previously authorized rates of return on common equity are frequently referenced as the basis for estimating equity risk premiums. The rates of return on common equity authorized electric utilities by regulatory commissions across the U.S. are compiled by Regulatory Research Associates, Inc. (RRA) and published in its *Regulatory Focus* report. In Exhibit TC-14, the average yield on public utility bonds is subtracted from the average allowed rate of return on common equity for electric utilities to calculate equity risk premiums for each year between 1974 and 2000. Over this period, these equity risk premiums for utilities averaged 3.05 percent, and the yield on public utility bonds averaged 9.97 percent.

Q. Is there any risk premium behavior that needs to be considered when implementing the risk premium method?

A. Yes. Although the realized rate of return method assumes that equity risk premiums are constant over time, there is considerable evidence that the magnitude of equity risk premiums is not constant and that equity risk premiums tend to move inversely with interest rates. In other words, when interest rate levels are relatively high, equity risk premiums narrow, and when interest rates are relatively low, equity risk premiums widen. To illustrate, the graph below plots the yields on public utility bonds (shaded bars) and equity risk premiums (solid bars) shown on Exhibit TC-14:



The graph clearly illustrates that the higher the level of interest rates, the lower the equity risk premium, and vice versa. The implication of this inverse relationship is that the cost of equity does not move as much as, or in lockstep with, interest rates. Accordingly, for a 1- percent increase or decrease in interest rates, the cost of equity may only rise or fall, say, 50 basis points. Therefore, when implementing the risk premium method, adjustments may be required to incorporate this inverse relationship if current interest rate levels have changed since the equity risk premiums were estimated. Finally, it is important to recognize that, for an industry in transition like the utility sector, the historical focus of the risk premium studies almost certainly ensures that they fail to fully capture the risks investors perceive going forward as utilities' markets are opened to competition. As a result, they are likely to understate the cost of equity for a firm operating in today's electric power industry.

Q. What cost of equity is implied by surveys of allowed rates of return on equity?

A. As illustrated above, the inverse relationship between interest rates and equity risk premiums is evident. Based on the regression equation between the interest rates and equity risk premiums displayed at the bottom of Exhibit TC-14, the equity risk premium for electric utilities increased approximately 45 basis points for each percentage point drop in the yield on average public utility bonds. As illustrated there, with the yield on average public utility bonds in September 2001 being 7.73 percent, this implied a current equity risk premium of 4.06 percent for electric utilities. Adding this equity risk premium to the September 2001 yield on single-A public utility bonds of 7.75 percent produces a current cost of equity of 11.81 percent.

Q. How did you apply the realized-rate-of-return approach?

A. Widely used in academia, the realized-rate-of-return approach is based on the assumption that, given a sufficiently large number of observations over long historical periods, average realized market rates of return will converge to investors' required rates of return. From a more practical perspective, investors may base their expectations for the future on, or may have come to expect that they will earn, rates of return corresponding to those realized in the past.

Stock price and dividend data for the electric utilities included in the *S&P 500* are available since 1946. Exhibit TC-15 presents annual realized rates of return for these electric utilities in each year between 1946 and 2000. As shown there, over this 55-year period realized rates of return for these utilities have exceeded those on single-A public utility bonds by an average of 5.10 percent. As noted earlier, the realized-rate-of-return method ignores the inverse relationship between equity risk premiums and interest rates and assumes that equity risk premiums are stationary over time; therefore, no adjustment for differences between historical and current interest rate levels was made. Adding this 5.10-percent equity risk premium to the September 2001 yield of 7.75 percent on single-A public utility bonds produces a current cost of equity for electric utilities of 12.85 percent.

IV. RETURN ON EQUITY FOR TRANSCONNECT

Q. What is the purpose of this section?

A. This section addresses the legal and economic requirements for TransConnect's rate of return on equity. In addition, this section discusses the regulatory policy reasons for avoiding a return on equity so low that it would prevent TransConnect from accomplishing its mission of strengthening the transmission system and developing into an independent entity capable of obtaining capital in its own name. Next, capital market evidence regarding the additional return necessary to compensate for TransConnect’s relatively small size and heavy financing burdens was examined. In light of these considerations and the goals envisioned in the Commission’s Order 2000, the final step was to evaluate where in the range of capital market benchmarks TransConnect's cost of equity should be established.

A. Economic Requirements

Q. Why is it important to allow TransConnect an adequate rate of return?

A. As discussed earlier, the U.S. transmission grid was not designed to accommodate a restructured, competitive electric power industry. It is for this reason that TransConnect, and other transmission entities, will spend hundreds of millions of dollars to upgrade the existing transmission system to maintain and improve reliability. In a review of the country’s transmission network, *S&P* expressed concern about recent difficulties caused by delays in enhancing the effectiveness of transmission and distribution systems:

> Standard & Poor’s firmly believes that “wires” companies will not allocate capital beyond their immediate needs to maintain the current system until

> they know the rules of the road (*i.e.*, who pays and who benefits). ...The longer this uncertainty continues, the greater the gap will be between transmission reliability and customer needs.
>
> Standard & Poor's concern is that transmission-focused utilities could be forced to access the capital markets aggressively in order to play catch-up.[41]

S&P pointed out the increasing demands placed on the transmission system by wholesale markets. At the same time the social cost of outages is continuing to increase as our society becomes more dependent on uninterrupted electric supply:

> The Aug. 10, 1996, outage in California alone cost an estimated $1 billion. Traditionally, utilities would be adding new transmission capacity to handle the expected load increase. However, because of the difficulty in obtaining permits and the uncertainty over obtaining adequate rate of return on investment, the total of transmission circuit miles added yearly is declining while total demand for transmission resources continues to grow.[42]

A recent Fortune magazine article also discussed the critical need to ensure the integrity of the nation's transmission system and the potential impact of inadequate investment on the U.S. economy:

> Utility investments in high voltage power lines, our electrical superhighways, have been falling since the late 1970s. …This trend, not the generator shortage that plagues California, is the main threat to the system nationwide. But the fallout nationwide may be much the same as in California: sky-high electric prices during periods of peak demand and a calamitous drop in the system's reliability. If the California crisis is a heart attack, the clogging of the transmission grid is the atherosclerosis that precedes it.[43]

In efficient, competitive markets, additional resources are devoted to services as they grow in importance and provide more value to consumers. Transmission services are

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[41] Standard & Poor's, "Electricity Transmission Bottlenecks Give Cause for Concern", *CreditWeek*, p. 19 (September 1, 1999).

[42] Standard & Poor's, "The Growing Vulnerability of the U.S. Power Grid," *Utilities & Perspectives*, p. 1 (Nov. 8, 1999).

[43] Fortune, "The Real Threat To America's Power: Sure, California is suffering from a generator shortage – but overloaded power lines pose a much greater risk of blowing the fuses of the national economy", p. 136 (March 5, 2001).

becoming more critical to ensure reliability and facilitate the development of competitive electric markets that promise enormous economic benefits. Yet, investment in the transmission grid has been declining, not increasing. In light of this contradiction, it is not surprising that this Commission has taken action in Order 2000. Dedicated transmission utilities like TransConnect have the potential of breaking the investment logjam.

Q. Have the inadequacies of the nation's electric transmission system been recognized by state regulators?

A. Yes. On behalf of *S&P*, RKS Research and Consulting (RKS) recently conducted a nationwide survey of state regulators and staff members in 46 jurisdictions to assess their perceptions regarding the consequences of electric utility deregulation. RKS concluded that reliability and transmission adequacy problems were uppermost in the respondents' minds, with the capability of the nation's transmission system being an area of clear concern:

> Only 12% of commissioners and no staffers described the current grid as "fully adequate," RKS said. "In fact, the responses generally reflect a sense that the transmission system, at present, is little better than barely adequate," the survey added.[44]

Q. What are the benefits to the public from TransConnect's successful development as an independent entity capable of raising capital in its own name?

A. TransConnect has been given the mission of developing an independent capability to raise capital and increase investment in transmission facilities. Consistent with this Commission’s Order 2000, an enhanced transmission system will provide the benefits of increased reliability and facilitate the development of effective competition in the market for electricity. Given the inadequate levels of past transmission investment, it is crucial that TransConnect be able to attract the economic resources necessary to meet these goals. Independence has its price, however, and TransConnect’s securities must be able

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[44] McGraw Hill, Inc., "California fallout has 'profound impact' in other states, survey says", *Retail Services Report*, p. 1 (May 4, 2001).

to compete in the capital market with the stocks and bonds of larger, more diversified utilities with long credit histories. *S&P* succinctly outlined the benefits of transmission companies successfully competing for capital:

> Since the FERC is expected ultimately to require that control of all transmission assets be separated from companies that retain generation, the creation of a Transco seems to hold the greatest potential for enabling development of a robust national electric transmission system that allocates capital in the most credit-efficient manner. If properly structured, an independent transmission system would catalyze the development of a competitive electric generation market, providing reduced market price volatility and more stable cash flows to all participating generation and distribution service providers.[45]

In short, independent transmission companies can act as a catalyst for developing truly competitive electricity markets.

Q. Has this Commission recognized the benefits to the public of competition in the bulk power market?

A. Yes. Order 2000 noted that the competition facilitated by investment in the transmission system directly benefits consumers:

> Trade in bulk power markets has continued to increase significantly and the Nation's transmission grid is being used more heavily and in new ways.
>
> ...Competition in wholesale electricity markets is the best way to protect the public interest and ensure that electricity consumers pay the lowest price possible for reliable service.[46]

Order 2000 pointed out that the ability to optimize generation through competitive markets has the potential for enormous economic benefits:

> [F]ull development of RTOs as envisioned by the Commission in this rule could offer substantial economic benefits. The EA [Environmental Assessment] scenarios modeled resulted in average annual savings of up to $5.1 billion per year over the 2000–2015 period.

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[45] Standard & Poor's, "Transcos—A New Form of Utility Entity," *Utilities & Perspectives*, p. 3 (Mar. 15, 1999).
[46] FERC Order 2000 at 2-3 (Feb 25, 2000).

> These estimates do not represent a complete economic analysis of the rulemaking because the EA analysis addressed only factors that may change the dispatch of power plants or future generating capacity decisions. ...
>
> …[O]ur best estimate of cost savings from RTO formation is $2.4 billion annually, with potential cost savings estimated to be as high as $5.1 billion annually. This represents about 1.1 to 2.4 percent of the current total costs of the U.S. electric power industry. Such savings can be considered in the context of recent analysis of the economic benefits of further industry restructuring. The wholesale cost savings the Commission is anticipating from the formation RTOs are properly viewed as distinct from the larger savings that may result from competitive retail power markets. However, RTOs can also help achieve retail access and its associated benefits by creating a robust wholesale power market. In this sense the cost savings from retail access depend on the Commission fulfilling its RTO objectives.[47]

But in order to develop the transmission network necessary to support effective competition, firms such as TransConnect must be able to attract the capital required to maintain the transmission system and finance construction expenditures. Aside from legal requirements embodied in the *Hope* and *Bluefield* tests of capital attraction, financial integrity, and comparable earnings, authorized rate of returns must reflect current capital market conditions and the greater risks of a restructured electric industry if the benefits envisioned by the Commission are to be realized. Indeed, *S&P* expressed the investment community's view on this issue:

> The FERC can provide economic incentives to stimulate transmission investment and improve electric reliability. Clearly, recent decisions to award single-digit returns on transmission assets will not induce the deployment of capital that competes in the dot-com marketplace. In addition, uncertainty over return on capital has impeded technological advance designed to increase transportability using the existing infrastructure, such as thyristors. A firm resolve by the FERC with allowed returns more in line with market expectations could provide the needed catalyst to spur investment.[48]

[47] *Ibid.* at 93-96.

[48] Standard & Poor’s, “Breaches in U.S. Electric Transmission System are Likely for Summer 2000”, *Utilities & Perspectives*, p.2 (June 26, 2000).

Q. What ROE would be required to ensure access to capital for TransConnect?

A. Given the untested nature of transmission companies, there is no exact way of knowing what level of ROE is necessary to ensure access to capital. Clearly, investors will need to be compensated for the level of risk they are bearing. In addition, the transition to a new and untested structure, no matter how conceptually well reasoned, creates uncertainty. This was recognized by this Commission in clarifying Order 2000:

> The Final Rule draws no conclusions about the risks of a transmission-only business. It simply observes that the uncertainty created during the restructuring transition may increase risk. We have not prejudged the risk issue, and that issue will be determined case-by-case.[49]

Q. In the future, will the Commission be able to refine the ROE for TransConnect and similar transmission companies?

A. Yes. Once the transition is accomplished, many uncertainties will be resolved. Moreover, the stocks and bonds issued by these companies will have an established track record, and investors' required returns can be directly inferred from market data. In the meantime, it is crucial that the initial allowed return be sufficient to encourage the flow of capital into transmission investments vital to the development of efficient, competitive markets for electricity. If the return is initially set at a level that does not support investor confidence, the damage may not be easily reversible. Not only would critical time be lost in bringing new projects on line, but once lost, investor confidence is difficult to recover. Consider the example of bond ratings. To restore a company's rating to a previous, higher level, rating agencies generally require the company to maintain its financial indicators above the minimum levels required for the higher rating.

The cost of providing an adequate ROE to TransConnect is small relative to both the potential benefits that a strong transmission system can have in facilitating the development of a vibrant wholesale power market and the extreme burden imposed by a flawed restructuring effort. The California crisis provides a graphic illustration of the economic damage wrought by market imbalances and ineffective competition.

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[49] FERC Order 2000 at 87 (Feb 25, 2000).

Consumers and the state's economy have suffered the results of volatile power costs, which have threatened to strangle economic growth.[50] As *Moody's* recognized, the Northwest region continues to experience similar, albeit less severe, strains in its power markets:

> (T)oday we note significant similarities between California and the Northwest whereby reserve margins have tightened because of the dearth of new generation capacity being built, making dependence on the spot market a much more expensive proposition. From time-to-time, this situation has been compounded by unscheduled and/or poorly timed maintenance outages, as well as extreme weather conditions. In the end, the basic economic law of supply and demand has caused unprecedented price volatility for electricity in the regional wholesale energy markets to persist.[51]

Apart from its immediate impact of the economy, a failed transition also imperils future prosperity by retarding progress to a truly competitive power market. In fact, a "re-regulation" backlash in response to market dislocations would deny participants the long-run benefits of competition altogether.[52] And in contrast to the speed at which market conditions can deteriorate, there is a noticeable lack of "quick-fix" solutions. To ensure investor confidence in this new company as it approaches the capital market for the first time will require an adequate ROE. The urgency of attracting new capital

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[50] As The Economist reported in "California's Power Crisis: A state of gloom", p. 55 (January 20, 2001):

> *California's energy crisis could magnify the downside for the whole economy. In the end, the state's energy crisis could prove to be an unwanted wild card for the American financial markets and the global economy at large.*

[51] Moody's Investors Service, *The Northwest Region's Energy Supply Situation, "More Manageable Than California, But Not Risk Free"*, p. 4 (January 2001).

[52] Standard & Poor's noted in "U.S. Electricity Deregulation: Are We Up to Our Neck in Alligators?", *CreditWeek*, p. 22 (November 29, 2000):

> *Consumers who were faced with this past summer's sky-high electricity prices are throwing electricity deregulation back to the politicians and regulators. For those whose electricity bills more than double, it is difficult to conceive how electricity deregulation was supposed to lower electricity bills. Politicians are now looking to score points with their constituents by proposing price caps, and re-regulation, among other retroactive, short-term measures. It is reminiscent of the old adage, "When you're up to your neck in alligators, it's hard to remember that all you wanted to do was drain the swamp!" The industry and its regulators now risk fighting short-term survival issues at the expense of continuing with long-term competition solutions.*

investment to transmission assets precludes experimenting with lower ROEs for TransConnect.

B. Other Factors

Q. How do the investment risks associated with TransConnect compare to those of the reference groups?

A. The average bond rating for the companies included in the gas pipeline reference group is A3 and BBB+ by *Moody's* and *S&P*, respectively, while the electric utility benchmark groups are both rated single-A. These average bond ratings are roughly comparable to the low investment grade rating expected for TransConnect. Similarly, TransConnect's expected common equity ratio of approximately 50 percent falls within the range of capital structures maintained by the reference groups of gas transmission and electric utilities.[53] Moreover, investors anticipate that common equity ratios for electric utilities will increase, consistent with the greater business risk associated with the power industry.[54]

Q. How does TransConnect's requested capital structure compare with other widely cited financial benchmarks available for utilities?

A. *S&P* routinely publishes financial ratio guidelines corresponding to specific bond ratings. Widely cited in the investment community, these ratios are viewed in conjunction with a utility's *business profile* ranking, which ranges from 1 (strong) to 10 (weak) depending on a utility's relative business risks. Thus, *S&P's* guideline financial ratios for a given rating category (e.g., single-A) vary with the business or operating risk of the utility. In other words, a firm with a *business profile* of "2" (i.e., relatively lower business risk) could presumably employ more financial leverage than a utility with a business profile

[53] Common equity ratios for the firms in the gas transmission group at year-end 2000 ranged from 31 to 62 percent. For the *Moody's* Electric Utilities, common equity represented between approximately 39 and 52 percent of capital, while the *S&P* electric utility group maintained individual common equity ratios ranging between 31 and 55 percent.

[54] *Value Line* reports in its October 5, 2001 edition (p. 695) that the average common equity ratio for the firms in the electric utility industry is expected to increase from 40.5 percent in 2000 to 48.5 percent in 2004-2006.

assessment of "9" while maintaining the same credit rating. The average *business profile* ranking assigned to the natural gas pipeline and electric utility reference groups is "5". S&P last published revised financial benchmarks in 1999, noting that:

> Standard & Poor's has created a single set of financial targets that can be applied across the different utility segments. These financial measures reflect the convergence that is occurring throughout the utility industry and the changing risk profile of the industry in general.[55]

Consistent with these revised guidelines and the average *business profile* ranking of "5" assigned to the reference groups, a utility would be required to maintain a ratio of total-debt-to-total-capital in the range of 41.5 to 47 percent in order to qualify for a single-A bond rating. In turn, this implies a total equity ratio on the order of 53 to 58.5 percent. *S&P* also reported that, on average, common equity represented approximately 48 percent of total long-term capital for U.S. electric utilities during 1999.[56] TransConnect's proposed capital structure is consistent with these guidelines, especially when considering the increasing uncertainties associated with restructuring in the power industry.

Q. Are capital market estimates for the benchmark groups of gas transmission and electric utilities directly applicable to TransConnect?

A. No. Total capital for the firms in the reference groups averaged between approximately $7.1 to $10.9 billion, versus TransConnect's expected initial capitalization attributable to the Applicants of $907 million. For a variety of reasons (*e.g.*, greater diversification and more resources), larger firms are typically regarded as less risky than smaller firms. The greater investment risk associated with smaller firms is well established in the financial literature. For example, in the study cited earlier, Professors Fama and French concluded that a firm’s relative size is a proxy for risk.[57] Similarly, various studies of utility bond ratings have shown that larger companies are assigned higher bond ratings than smaller

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[55] Standard & Poor's, "Utility Financial Targets Are Revised", *Utilities & Perspectives*, p. 1 (June 21, 1999).
[56] Standard & Poor's Corporation, *Corporate Ratings Criteria*, p. 54.
[57] Fama & French, *supra* n.53.

firms.[58] And finally, there is ample empirical evidence that investors in smaller firms realize higher rates of return than in larger firms.[59]

Q. What evidence is there regarding the magnitude of the difference between the cost of equity for large companies and for small companies?

A. In addition to the data cited earlier for the large, publicly traded firms included in the *S&P 500*, Ibbotson Associates also reports realized rates of return for "Mid-Cap" and "Low-Cap" stocks. Mid-Cap companies comprise the 3rd through 5th size-deciles of those stocks listed on the New York Stock Exchange, American Stock Exchange, and NASDAQ, while Low-Cap stocks represent the 6th through 8th size-deciles. The individual firms in the Mid-Cap group have market capitalizations at or below about $4,144 million but greater than $840 million, with the market capitalization of Low-Cap stocks falling between approximately $840 million and $193 million. These smaller companies have historically earned higher rates of return than the large companies comprising the *S&P 500*. For the 1926 to 2000 period, Ibbotson Associates reported that realized rates of return on Mid-Cap and Low-Cap stocks exceeded those on the *S&P 500* by 150 and 270 basis points, respectively.[60]

Q. Is there any other evidence that quantifies the difference in the cost of equity between large and small utilities?

A. Yes. A study reported in PUBLIC UTILITIES FORTNIGHTLY noted that the betas of small companies do not fully account for the higher realized rates of return associated with small company stocks:

> The smaller deciles show returns not fully explainable by the CAPM. The difference in risk premium (realized versus CAPM) grows larger as one moves from the largest companies in decile 1 to the smallest in decile 10.

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[58] *See, e.g.*, Pinches, George E., Singleton, J. Clay & Janankhani, Ali, *Fixed Coverage as a Determinant of Electric Utility Bond Ratings*, FINANCIAL MANAGEMENT (Summer 1978).
[59] *See, e.g.,* Banz, Rolf E., *The Relationship Between Return and Market Value of Common Stocks,* JOURNAL OF FINANCIAL ECONOMICS (Sept. 1981).
[60] Ibbotson Associates, *2001 Yearbook*, pp. 124-125 (2001).

> The difference is especially pronounced for deciles 9 and 10, which contain the smallest companies.[61]

The study went on to conclude that a publicly traded utility with a market capitalization of $400 million would require a small company premium of at least 210 basis points above the rate of return for larger firms.

Q. Has this Commission recognized that small utilities may have higher ROE requirements in their startup years?

A. Yes. There is precedent for higher return requirements for smaller, younger companies. For example, FERC has allowed four small natural gas pipelines ROEs of 14 percent in recent cases.[62] The wisdom of FERC's recognition that investors require higher returns to venture from the comparative safety of large, integrated utilities is obvious. Large companies enjoy many advantages in accessing capital markets. Investors take comfort in their familiarity with such companies and their histories of meeting interest and principal payment obligations while declaring stable or gradually increasing dividends over the decades. Large, diversified companies can more easily weather unpleasant surprises in one or more markets because bad news in one business can be offset by good news elsewhere. By contrast, small companies have all their eggs in one basket.

Q. What else should be considered in comparing TransConnect with reference groups?

A. As discussed earlier, TransConnect plans to implement an ambitious program of capital expenditures to enhance the effectiveness of the transmission network. As a result, TransConnect is expected to have significant external capital requirements in the near future. In contrast, five of the seven gas pipelines are projected to have adequate internal cash flow to meet capital expenditures, with internal cash flow expected to exceed annual

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[61] Annin, Michael, *Equity and the Small-Stock Effect*, PUBLIC UTILITIES FORTNIGHTLY, p. 43 (Oct. 15, 1995).

[62] The four companies are Questar Southern Trails Pipeline Co. (CP99-163-000, et al.), Buccaneer Gas Pipeline Co. LLC (CP00-14-000, et al.), Gulfstream Natural Gas System, LLC (CP00-6-000, et al.), and Guardian Pipeline, LLC (CP00-36-000).

capital expenditures for all but three of the firms in the *Moody's* and *S&P* Electric Utilities groups.

Q. Will TransConnect incur any costs to obtain additional capital?

A. Yes. To achieve the goals of increased infrastructure investment and financial independence, TransConnect plans to obtain financing by accessing the public capital markets either directly or through the Corporate Manager. The sale of common stock will provide the TransConnect with increased financial flexibility through access to a greater pool of potential investors while avoiding the additional return that would otherwise be required to compensate for non-marketability.

These benefits have an attendant cost, however, in the form of the issuance expenses that will be required to facilitate the IPO, which is expected in about three years. In addition to accounting and legal fees necessary to meet regulatory requirements, the Corporate Manager will incur transactions and brokerage costs associated with underwriting the new issue. Issuance costs increase progressively for small sized issues and can be considerably higher for an IPO, with total expenses generally ranging from about 9 percent to as high as 20 percent.[63]

Following its IPO, TransConnect or its Corporate Manager will continue to incur the costs of "floating" new equity securities to support planned capital expenditures. Also, the "market pressure" from the additional supply of common stock and other market factors may further reduce the amount of funds Corporate Manager will net when it issues common equity. Given the magnitude of TransConnect's capital budget and the relatively large proportion of this new investment that must be financed through external sources, these issuance costs are far more significant for TransConnect than for the utilities in the benchmark groups.

Q. Is there an established mechanism for a utility to recognize equity issuance costs?

A. No. While debt flotation costs are recorded on the books of the utility, amortized over the life of the issue, and thus increase the effective cost of debt capital, there is no similar

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[63] Pratt, Shannon P., Reilly, Robert F., & Schweihs, Robert P., VALUING A BUSINESS, p. 353 (3d ed. 1996).

accounting treatment to ensure that equity flotation costs are recorded and ultimately recognized. Alternatively, no rate of return is authorized on flotation costs necessarily incurred to obtain a portion of the equity capital used to finance plant. In other words, equity flotation costs are not included in a utility's rate base because neither that portion of the gross proceeds from the sale of common stock used to pay flotation costs is available to invest in plant and equipment, nor are flotation costs capitalized as an intangible asset. Unless some provision is made to recognize these issuance costs, a utility's revenue requirements will not fully reflect all of the costs incurred for the use of investors' funds. Because there is no accounting convention to accumulate the flotation costs associated with equity issues, they must be accounted for indirectly, with an upward adjustment to the cost of equity being the most logical mechanism.

Q. What is the magnitude of the adjustment to the "bare bones" cost of equity to account for issuance costs?

A. There are any number of ways in which a flotation cost adjustment can be calculated, and the adjustment can range from just a few basis points to more than a full percent. One of the most common methods used to account for flotation costs in regulatory proceedings is to apply an average flotation-cost percentage to a utility's dividend yield. Based on a review of the finance literature, Roger A. Morin concluded:

> The flotation cost allowance requires an estimated adjustment to the return on equity of approximately 5% to 10%, depending on the size and risk of the issue.[64]

Applying these expense percentages to a representative dividend yield for an electric utility of 4.5 percent implies a flotation cost adjustment in the range of 23 to 45 basis points. In light of TransConnect's relatively small size, the magnitude of its capital budget, the greater cost of an IPO, and the fact that TransConnect currently has no

[64] Morin, Roger A., REGULATORY FINANCE: UTILITIES' COST OF CAPITAL, p. 166 (1994).

publicly traded stock outstanding, an adjustment for issuance and flotation costs at even the upper end of this range is likely to be conservative.[65]

Q. What is your capital market estimate of the size and financing adjustments associated with TransConnect?

A. Evidence of the size effect suggests an adjustment of 150 to 270 basis points, while the financing effect is conservatively estimated at 23 to 45 basis points.

C. Recommendation

Q. What then is your recommended ROE range for TransConnect?

A. Based on the capital market research presented earlier and my experience with startup companies, it is my opinion that the reasonable ROE range for TransConnect is between 12.0 percent and 15.5 percent. A return within this range should be sufficient to ensure the successful startup of TransConnect and support its bond IPO in 2001 and subsequent stock IPO in about three years. As TransConnect and other independent transmission companies develop a track record and the market has an opportunity to assess the risk of their debt and equity, the ROE range can be refined. The 12.0 to 15.5 percent range is reasonable at this critical juncture, given the importance of developing a company with the financial capability of raising the capital that is urgently needed for transmission infrastructure investments. The payoff from stimulating transmission investment and furthering the development of effective competition is so large that the incremental impact of the ROE on the total cost of electricity to consumers pales into insignificance.

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[65] In Order No. 420, 91 FERC ¶ 61,168 (1985), FERC recognized the need to compensate utilities for issuance expenses on new stock sales. Adjusting for these expenses increased the generic ROE for electric utilities by only six basis points. The financing cost facing TransConnect differs significantly from the situation faced by integrated utilities in the mid-1980s. First, TransConnect will incur IPO expenses that are several times larger – as a percentage of proceeds – than an additional equity issue by utilities that have an established public market for their shares. Second, even after the IPO, TransConnect will require follow-up equity issues to raise the large amounts of capital required for transmission investment. New equity issues are relatively infrequent for established electric utilities.

Q. Is your recommended range of reasonableness for TransConnect consistent with the capital market evidence developed earlier in your testimony?

A. Yes. As discussed earlier, cost of equity estimates for the gas transmission group produced by the Commission's two-step DCF model ranged from 10.4 to 15.0 percent with a median of 14.1 percent. Cost of equity estimates for the three pipelines typically referenced by FERC fell in a narrower range of 14.1 to 14.4 percent. Of course, pipelines have almost a decade of experience in a restructured industry, while electric transmission companies are nascent. The fact that TransConnect will be 1) a relatively small, newly formed company with no track record; 2) entering a new industry without established business practices; and, 3) raising a significant amount of additional capital through the sale of new securities indicates that its cost of equity would fall at least in the upper end of the range for the reference group of natural gas transmission companies.

With respect to the two reference groups of electric utilities, my recommended 12.0 to 15.5 percent range of reasonableness falls within the range of required rates of return indicated by applying the DCF approach used by the Commission in *Southern California Edison*. As indicated earlier, application of the Commission's one-step DCF model to the firms in the *Moody's* Electric Utilities group resulted in a range of reasonableness of 9.4 to 13.4 percent. For the *S&P* electric group, the Commission's one-step DCF model produced a cost of equity range of 9.2 to 18.0 percent, with the midpoint being 13.6 percent.

Q. In selecting a rate of return from within your range of reasonableness, is it appropriate to consider other risks that distinguish TransConnect from the firms in the reference groups?

A. Yes. Whereas TransConnect's business will be limited in size and restricted solely to electric transmission, the companies in the reference groups are relatively large and most enjoy some degree of diversification either as vertically integrated electric utilities or because of involvement in other business activities. In my experience with both regulated and unregulated businesses, investors associate lack of diversification with greater risk and generally require higher returns from startup companies. In addition, as discussed previously, TransConnect's lack of operating history and smaller size relative to the reference groups of gas transmission and electric utilities also may add to investors' return requirements. Moreover, while all but five of the firms in the reference groups of gas pipelines and electric utilities are projected to have sufficient internally generated funds to meet capital expenditures, TransConnect is expected to have to raise substantial amounts of external capital to meet its capital expenditure requirements. Investors may perceive TransConnect's significant capital spending requirements to be unattractive because the new capital funds may dilute their ownership and introduce new claimants to the company's earnings and assets. TransConnect will also incur additional costs associated with "floating" additional common equity. Finally, as discussed in the testimony of Ms. Carolyn J. Cowan, there are other unique risks associated with TransConnect that expose investors to significant additional uncertainties.

Because investors require compensation in order to bear additional risks, these uncertainties are properly considered in selecting the rate of return from within the recommended range. The magnitude of the ROE adjustments to account for size and issuance costs, the fact that TransConnect will be an untested company, and the risk factors discussed in the testimony of Ms. Cowan all support the conclusion that TransConnect's cost of equity exceeds investors' required rate of return for the reference groups of gas transmission and electric utilities. Given the importance of encouraging necessary enhancements to the transmission infrastructure and the risks faced by transmission utilities generally, and TransConnect specifically, a rate of return on common equity above the midpoint of my 12.0 to 15.5 percent range is reasonable at this critical juncture.

Q. How does TransConnect's requested 14.5 percent ROE compare with other benchmarks that investors would consider in assessing the adequacy of the rate of return on equity?

A. Probably the most frequently cited rates of return are those for the *S&P 500*. Ibbotson Associates reported that an investment in the common stock of these 500 firms produced an average annual rate of return of 13.0 percent over the period 1926 through 2000, with the average rate of return realized over the last decade being 18.4 percent per year.[66] During the decade 1990-1999, the *S&P 500* companies earned an average of 16.3 percent on book equity, and an average of 20.7 percent per year between 1995 and 1999.[67] Finally, as noted earlier, applying the constant growth DCF model to the S&P 500 companies indicates that investors expect to earn a return of 16.8 percent from an investment in the *S&P 500*.

Another source of rate of return benchmarks is provided by the *Value Line Composite* of 746 industrial, retail, and transportation companies. Over the last ten and five years, the companies in the *Value Line Composite* have earned average annual rates of return of book equity of 16.8 percent and 18.2 percent, respectively.[68] In addition, Value Line projects that this same group of firms will earn 16.3 percent on book equity during the 2004-2006 time frame.[69]

Q. How do you reconcile these ROEs with the rates of return on common equity authorized by regulators for utilities?

A. The rates of return on equity authorized by regulators are the result of conventional cost-based regulation. As such, they represent the cost of equity, which as discussed earlier, is the *minimum* compensation investors require for the use of their equity capital. This contrasts with the rates of return on equity being realized and expected in other sectors of the economy.

Q. Please elaborate on the difference between these values.

A. Conventional rate base/rate of return regulation can be viewed as essentially a cost-reimbursing process. A utility incurs operating and capital costs, and these costs are then included in the rates charged to customers. Under this cost-based paradigm, only the cost

[66] Ibbotson Associates, "2001 Yearbook: Market Results for 1926-2000", pp. 23 & 31 (2001). Ibbotson Associates also reported that investors in their group of "Small Company" stocks realized total returns of 17.3 percent from 1926 to 2000, or 18.6 percent over the last decade.

[67] Standard & Poor's, *Analysts' Handbook*

[68] The Value Line Investment Survey, *Value Line Selection & Opinion*, p. 4145 (July 20, 2001).

[69] *Ibid*.

of equity is included in rates, with all dollars received from customers as return on equity serving to compensate shareholders for the minimum rent for the use of their capital. With this form of cost-based ratemaking, there are no economic profits (i.e., a return above the cost of equity), with the utility simply recovering its costs and nothing more.

Q. What is the end-result of their being no economic profits under conventional cost-based regulation?

A. Absent the prospect of earning returns above the bare bones cost of equity, there is a limited incentive for the utility to invest additional capital and take risks. Indeed, if a utility is only allowed to earn its cost of capital, raising more capital for additional investment only makes it bigger, not more valuable. Likewise, there is little reason to risk capital in projects where the utility recovers nothing more than its costs, especially given the risk of disallowance if it is not successful. The utility's rational economic response to this form of ratemaking is, of course, to play it safe. It makes no sense for the utility to expose capital to any unnecessary risks; instead, the more prudent course is to proceed cautiously.

Q. Is conventional cost-based ratemaking consistent with the incentives in the competitive sector of the economy?

A. No. Economic profit is the engine that drives investment, innovation, and efficiency. The basic decision-making rule in the competitive sector is that, if a project is not expected to earn returns greater than the cost of capital, then it is rejected. Indeed, this explains why successful companies in the competitive sector earn, both for investors and on their book equity, rates of return higher than the bare-bones cost of equity.

Q. If there are limited incentives under conventional cost-based ratemaking, why is it still practiced?

A. Historically, regulation focused on preventing utilities from exercising their market control to earn monopoly profits. However, as technologies have changed and the economy has become more customer-oriented, regulation is increasingly focusing on ways to encourage innovation, responsiveness, and increased service and efficiency. Recognizing that conventional cost-based regulation was an inhibiting factor stymieing change, many regulatory agencies have sought alternatives. This has led to a move away from conventional cost-based regulation and the adoption of a variety of performance-based regulatory schemes, most of which allow the utility to earn rates of return greater that the bare bones cost of equity. The Commission recently recognized the importance of providing incentives to stimulate investment and maximize power delivery in the Western U.S. by approving accelerated depreciation and ROE premiums for projects that enhance the transmission system within the Western Systems Coordinating Council.[70]

Q. What are the implication of this discussion for the present case?

A. TransConnect's requested 14.5 percent ROE falls within my 12.0 to 15.5 percent range of reasonableness for a transmission utility in today's capital markets, especially after considering TransConnect's relative size, capital requirements, and lack of operating history. More importantly, however, establishing a lower ROE for TransConnect would lower the economic profit incentives that would reward transmission companies for investing additional capital and taking risks. The payoff from stimulating transmission investment and furthering the development of effective competition is so large that the incremental impact of the ROE on the total cost of electricity to consumers pales into insignificance.

Q. Does this conclude your direct testimony in this case?

A. Yes, it does.

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[70] *Removing Obstacles To Increased Electric Generation And Natural Gas Supply In The Western United States*, Further Order Dismissing Petition for Rehearing, 95 FERC ¶ 61,225 (May 16, 2001).

APPENDIX A

Qualifications of William E. Avera