BEFORE THE
WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, **Complainant,** **v.** **PUGET SOUND ENERGY, INC.,** **Respondent.**	**Docket No. UG-040640** **Docket No. UE-040641** **(*consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Order Regarding the Accounting Treatment for Certain Costs of the Company's Power Cost Only Rate Filing.**	**Docket No. UE-031471 (*consolidated*)**
In the Matter of the Petition of **PUGET SOUND ENERGY, INC.** **For an Accounting Order Authorizing Deferral and Recovery of the Investment and Costs Related to the White River Hydroelectric Project.**	**Docket No. UE-032043 (*consolidated*)**

EXCERPTS OF NON-WASHINGTON AUTHORITIES
CITED IN THE INITIAL BRIEF OF
PUGET SOUND ENERGY, INC.
(WAC 480-07-395(1)(c)(vi))

JANUARY 18, 2005

Court Decisions

1. *Driscoll v. Edison Light & Power Co.*, 307 U.S. 104 (1939) .... Tab A

2. *West Ohio Gas Co. v. Public Utils. Comm'n of Ohio*, 294 U.S. 63 (1935) .... Tab B

Statutes of Other Jurisdictions

3. N.J. Rev. Stat §§48:3-49, *et seq* .... Tab C

4. Or. Rev. Stat. § 757.072 .... Tab D

Administrative Decisions of Other Jurisdictions

5. *Chazy & Westport Tel. Corp.*, 2003 N.Y. PUC LEXIS 475
   (N.Y. Pub. Serv. Comm'n Aug. 27, 2003) .... Tab E

6. *Conn. Power & Light Co.*, Docket No. 03-07-02, Decision
   (Conn. Dep't. of Pub. Util. Control Dec. 17, 2003) .... Tab F

7. *Crown Point Tel. Corp.*, 2003 N.Y. PUC LEXIS 474
   (N.Y. Pub. Serv. Comm'n Aug. 27, 2003) .... Tab G

8. *Jersey Cent. Power & Light Co.*, 2003 N.J. PUC Lexis 248
   (N.J. Bd. of Pub. Utils. Aug. 1, 2003) .... Tab H

9. *Kearsarge Tel. Co.*, Order No. 24,281, N.H PUC Cause No. DT01-221
   (N.H. Pub. Utils. Comm'n Feb. 20, 2004) .... Tab I

10. *Phillips County Tel. Co.*, 2003 Colo. PUC LEXIS 1428
    (Colo. Pub. Utils. Comm'n Dec. 31, 2003) .... Tab J

11. *Re Cincinnati Gas & Elec. Co.*, 42 PUR 4th 252(Ohio Pub. Utils. Comm'n 1981)... Tab K

12. *Re Delta Nat. Gas Co., Inc.*, 198 PUR 4th 132 (Ky. Pub. Serv. Comm'n 1999)........ Tab L

13. *Re Duke Power Co.*, 79 PUR 4th 145 (S.C. Pub. Serv. Comm'n 1986) .... Tab M

14. *Rockland Elec. Co.*, 2003 N.J. PUC Lexis 259
    (N.J. Bd. of Pub. Utils. July 21, 2003) .... Tab N

15. *St. Lawrence Gas Co.*, Inc., 2003 NY PUC Lexis 427
    (N.Y. Pub. Serv. Comm'n Aug. 4, 2003) .... Tab O

16. *Tenn.-Am. Water Co.*, Docket No. 03-00118, Final Order (Tenn. Regulatory Auth. June 25, 2004) .... Tab P

17. *Verizon N.H.*, Order No. 24,265, N.H. PUC Cause No. DT02-110 (N.H. Pub. Utils. Comm'n Jan. 16, 2004) .... Tab Q

18. *W. Va.-Am. Water Co.*, Case No. 03-0353-W-42T, Commission Order (W. Va. Pub. Serv. Comm'n Jan. 2, 2004) .... Tab R

Regulations of Other Jurisdictions

19. Or. Admin. R. 860-012-0100 .... Tab S

20. Or. Admin. R. 860-012-0190 .... Tab T

Other Authorities

21. Harris, Robert S. and Felicia C. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts; Practical Issues in Valuations," *Financial Management*, Volume 21, No. 2 (June 22, 1992) .... Tab U

22. Harris, Robert S. and Felicia C. Marston, "Risk and Return: A Revisit Using Unexpected Returns," *The Financial Review*, Vol. 28, No. 1, (Feb. 1993) .... Tab V

23. Harris, Robert S. and Felicia C. Marston, "The Market Risk Premium Expectational Estimates Using Analysts' Forecasts," University of Virginia, Darden Graduate School of Business, Working Paper No. 99-08 .... Tab W

Tab A

307 U.S. 104, *; 59 S. Ct. 715, **;
83 L. Ed. 1134, ***; 1939 U.S. LEXIS 649

DRISCOLL ET AL., CONSTITUTING PENNSYLVANIA PUBLIC UTILITY COMM'N, ET AL. v. EDISON LIGHT & POWER CO.

No. 509

SUPREME COURT OF THE UNITED STATES

307 U.S. 104; 59 S. Ct. 715; 83 L. Ed. 1134; 1939 U.S. LEXIS 649

February 7, 8, 1939, Argued
April 17, 1939, Decided

PRIOR HISTORY:

APPEAL FROM THE DISTRICT COURT OF THE UNITED STATES FOR THE EASTERN DISTRICT OF PENNSYLVANIA.

APPEAL from a decree of the District Court of three judges permanently enjoining the enforcement of temporary rates fixed for an electric power company.

DISPOSITION:

25 F.Supp. 192, reversed.

CORE TERMS: temporary, public utility, allowance, estimate, reproduction, fair value, fixing, depreciated, going concern value, injunction, indirect, physical property, depreciation, rate base, et seq, financing, working capital, public service, confiscatory, accrued depreciation, final determination, permanent injunction, operating expenses, rate proceeding, rate of return, reasonableness, expenditures, computation, prescribed, reduction

LexisNexis(R) Headnotes

SYLLABUS:

1. The provision of the Act of May 14, 1934, withholding from the District Courts jurisdiction over suits to enjoin on the ground of unconstitutionality the enforcement of state orders fixing public utility rates, "where a plain, speedy, and efficient remedy at law or in equity may be had in the courts of such State," -- *held* inapplicable by its terms to a suit attacking temporary rates ordered by the Public Utilities Commission in Pennsylvania, where the remedy by injunction is confined to proceedings "questioning the jurisdiction of the commission," and where the remedy at law by appeal does not postpone the rates *pendente lite*. Pp. 108 *et seq*.

2. The provisions of § 310 (a) of the Pennsylvania Public Utilities Act for fixing temporary public utility rates are not limited to utilities which keep continuing property records. Section 310 (b) furnishes a partial alternative method. P. 112.

3. Section 310 (a) of the Act empowers the commission to fix temporary rates, to be charged pending final determination of the rate proceedings, which shall be sufficient to provide a return of not less than 5% upon original cost, less accrued depreciation, of the utility's physical property used and useful in the public service. Section 309 requires that permanent rates when determined shall be "just and reasonable." In fixing the base for temporary rates in this case, the commission did not confine itself to the single factor of original cost less depreciation, but interpreted § 310 (a) as requiring that weight be given also to reproduction cost, going concern value and the necessity for working capital, in compliance with the rule laid down by this Court in *Smyth* v. *Ames*, 169 U.S. 400. *Held*, that in the absence of any decision of the state court on the subject, this interpretation of § 310 (a), not inconsistent with its terms, should be accepted. P. 114.

A different construction would raise the novel and important question of the constitutionality of a temporary rate, based solely on depreciated original cost, with provision of the statute for recoupment of the loss from insufficient temporary rates as provided in § 310 (e).

4. This Court adopts a just and reasonable construction of a state statute rendering it clearly constitutional rather than another that puts its validity in doubt. P. 115.

5. In determining a rate base, failure to include allowance for cost of financing is not erroneous where the evidence reveals no actual expenditures for that purpose and furnishes no foundation for an estimate. P. 116.

6. It does not appear from evidence that in determining rate base the commission failed in this case to make due allowances for going concern value; nor that, in estimating depreciated reproduction cost, it failed to make adequate allowance for indirect costs, such as interest, supervision, financing, taxes, legal expenses, or refused to consider claimed increase of prices. P. 117.

7. Six per cent. *held* not an inadequate rate of return in the case of an electric power company which operates in a stable community accustomed to the use of electricity and close to the capital markets, with funds readily available for secure investment. Long operation and adequate records make forecasts of net operating revenues fairly certain. Under such circumstances a six per cent. return after all allowable charges can not be confiscatory. P. 119.

8. Even where the rates in effect are excessive, in a proceeding by a commission to determine reasonableness the utility should be allowed its fair and proper expenses for presenting its side to the commission. P. 120.

9. In the allowance for such rate-case expenditures, the period over which they are to be amortized will depend upon the character of services received or disbursements made. P. 121.

There could rarely be an anticipation of annually recurring charges for rate regulation. Under the circumstances here presented where full statistics on investment, inventory and labor requirements have been made which, as cumulated, will form largely the basis of all future negotiations, the Court is of the opinion that amortization over a ten year period is reasonable.

COUNSEL:

Messrs. Guy K. Bard and Edward Knuff, with whom Messrs. Claude T. Reno, Attorney General of Pennsylvania, and Samuel Graff Miller, John C. Kelley, Harry H. Frank, and Herbert S. Levy were on the brief, for appellants. Mr. Herbert B. Cohen was on a brief for the Utility Consumers' League of York, Pa., appellant.

Mr. Clarence W. Miles, with whom Messrs. Walter Biddle Saul, Edward F. Huber, Bradford S. Magill, and J. Harry La Brum were on the brief, for appellee.

By leave of Court, briefs of amici curiae were filed by Solicitor General Jackson, Assistant Attorney General Arnold, and Messrs. Paul A. Freund, Robert M. Cooper, Milford Springer, David W. Robinson, Jr., Richard J. Connor, Charles W. Smith, William J. Dempsey, and William C. Koplovitz, on behalf of the United States; and by Messrs. Gay H. Brown and Sherman C. Ward, on behalf of the Public Service Commission of the State of New York, urging the constitutionality of the temporary-rate provision of the Pennsylvania statute.

JUDGES:

Hughes, McReynolds, Butler, Stone, Roberts, Black, Reed, Frankfurter, Douglas

OPINIONBY:

REED

OPINION:

[*107] [**716] [***1138] MR. JUSTICE REED delivered the opinion of the Court.

This is an appeal from the decree of a three-judge district court granting a permanent injunction against the enforcement [**717] of temporary rates. § 266, Jud. Code.

The appellants are five named persons, individually and as members of the Pennsylvania Public Utility Commission, and the Utility Consumers League of York, Pennsylvania, intervening defendant below, an unincorporated association of consumers of electric current in the territory served by the appellee. The latter is a public utility corporation organized under the laws of Pennsylvania, which generates, transmits, distributes and sells electric energy to approximately 30,000 customers in and about York, Pennsylvania.

An investigation to determine the reasonableness of appellee's rates was instituted on January 27, 1936. During its progress the state legislature recodified the utility law of Pennsylvania. Act of May 28, 1937, P. L. 1053, Purdon's Pa. Stat. Ann., 1938 Supp., Title 66, § 1101 *et seq.* It enacted a temporary rate section, 310, which is the source of this controversy.

Acting under § 310, the commission, after notice and argument, issued a temporary rate order on July 13, 1937, requiring the utility to file rate schedules which would effect a reduction of approximately $ 435,000 in annual gross operating revenues. This order was replaced by another on July 27, 1937, which commanded an identical reduction. This time the commission itself prescribed a [*108] schedule of rates. The utility filed a bill in equity in a statutory court in the Middle District of Pennsylvania. On October 15, 1937, a permanent injunction issued. n1 The Commission did not appeal. On November 30, 1937, another order was issued seeking to establish the same temporary rates and to secure the same reduction in gross revenues as the orders of July 13 and 27.

n1 *Edison Light & Power Co.* v. *Driscoll*, 21 F.Supp. 1.

On December 14, 1937, the utility filed a bill in the United States District Court for the Eastern District of Pennsylvania to enjoin this order. A three-judge court was convened under § 266 of the Judicial Code. By stipulation of the parties the application for an interlocutory injunction brought to hearing on January 17, 1938, was treated as an application for a permanent injunction. On October 14, 1938, a permanent injunction issued.

The court concluded as a matter of law that the utility had no plain, speedy and adequate remedy in the state courts; that the order is void because the "commission acted in direct violation of the mandatory provisions of the Public Utility Act which requires rates for [the company] to be fixed under paragraph (b) of section 310"; that the order is unconstitutional because (1) it violates the procedural requirements of due process, (2) it fails to permit the utility to earn a fair return on the fair value of its property used and useful in the public service, (3) it confiscates the company's property, and (4) it is not supported by substantial evidence. n2

n2 *Edison Light & Power Co.* v. *Driscoll*, 25 F.Supp. 192.

[***HR1] *Jurisdiction of the Statutory Court.* -- Except as modified by the Johnson Act, n3 jurisdiction exists in a statutory court, called pursuant to § 266 of [***1139] the Judicial Code, to hear and finally determine bills in equity seeking temporary [*109] and permanent injunctions against the order of a state administrative commission on the ground of irreparable injury. n4 By this amendatory act, where the order attacked as violative of the Federal Constitution affects the rates of a public utility, does not interfere with interstate commerce and has been made after notice and hearing, the jurisdiction of the district court to enjoin its enforcement is withdrawn, unless no "plain, speedy and efficient remedy may be had, at law or in equity, in the courts of such State." No challenge to the jurisdiction was made in the statutory court or on appeal. In response to questions from the bench, counsel for the commission conceded that there was no remedy in the state courts which would satisfy the Johnson Act.

n3 Judicial Code, § 24 (1), as amended by Act of May 14, 1934, c. 283, 48 Stat. 775.

n4 *Oklahoma Gas Co.* v. *Russell*, 261 U.S. 290, 292; *Herkness* v. *Irion*, 278 U.S. 92, 93.

[***HR2] The reason for this concession lies, so far as a remedy in equity is concerned, in the provision of the Pennsylvania statute forbidding an injunction against an order, "except in a proceeding questioning the jurisdiction of the commission." n5 [**718] The bill in certain allegations attacks the section of the Public Utility Law under which this order issued as violative of the Fourteenth Amendment in that it empowered the commission to fix noncompensatory and discriminatory temporary rates, in an arbitrary manner. In one sense this questions the jurisdiction [*110] of the commission. If § 310 is invalid, there is no other provision to authorize temporary rates. Jurisdiction is a word of uncertain meaning. As used in § 1111, *supra*, it apparently refers to proceedings by the commission under the terms of the statute. In this use it would permit an injunction, equitable grounds being shown, where the public utility is not covered by the act. Otherwise, action in excess of the powers of the commission, such as a confiscatory rate, might be deemed beyond its jurisdiction. At any rate, without an authoritative determination by the state courts, we cannot say, for this character of proceeding, that the remedy in the state courts is plain, speedy and efficient. n6 The remedy at law by appeal is ineffective to protect the utility's position *pendente lite*. The supersedeas does not postpone the application of the temporary rates. n7 The statutory court had jurisdiction of the bill.

n5 § 1111, P. L. 1053, Purdon's Pa. Stat. Ann., 1938 Supp., Title 66, § 1441: "Exclusive jurisdiction of Dauphin County Court to hear injunctions. -- No injunction shall issue modifying, suspending, staying, or annuling any order of the commission, or of a commissioner, except in a proceeding questioning the jurisdiction of the commission, and then only after cause shown upon a hearing. The court of common pleas of Dauphin County is hereby clothed with exclusive jurisdiction throughout the Commonwealth, of all proceedings for such injunctions, subject to an appeal to the Superior Court as aforesaid."

n6 *Mountain States Co.* v. *Comm'n*, 299 U.S. 167, 170; *Corporation Comm'n* v. *Cary*, 296 U.S. 452.

n7 § 1103, P. L. 1053, Purdon's Pa. Stat. Ann., 1938 Supp., Title 66, § 1433.

Statutory Basis for the Order. -- Sec. 310 n8 contains several subsections. The commission fixed the temporary rates under subsection (a). The district court concluded as a matter of law that this action was invalid because they could only be fixed under subsection (b). The two subsections are set out below. n9 In [**719] its opinion, without [*111] discussing § 310 (b), the court declared § 310 (a) unconstitutional [***1140] because it permitted the commission to fix a temporary rate based upon the single factor of original cost less depreciation. n10 The commission, however, did not confine itself to that one element in setting the fair value of the appellee's property, for the purpose of temporary rates, at $ 5,250,000. It gave weight to reproduction cost, original cost, going concern value and the necessity for working capital, and it allowed on this rate base a return of more than six per cent. This, of course, [*112] satisfies the requirement of § 310 (a) that the temporary rates shall produce not less than 5% on the "original cost, less accrued depreciation."

n8 P. L. 1053, Purdon's Pa. Stat. Ann., 1938 Supp., Title 66, § 1150.

n9 "Temporary Rates. -- (a) The commission may, in any proceeding involving the rates of a public utility brought either upon its own motion or upon complaint, after reasonable notice and hearing, if it be of opinion that the public interest so requires, immediately fix, determine, and prescribe temporary rates to be charged by such public utility, pending the final determination of such rate proceeding. Such temporary rates, so fixed, determined, and prescribed, shall be sufficient to provide a return of not less than five per centum upon the original cost, less accrued depreciation, of the physical property (when first devoted to public use) of such public utility, used and useful in the public service, and if the duly verified reports of such public utility to the commission do not show such original cost, less accrued depreciation, of such property, the commission may estimate such cost less depreciation and fix, determine, and prescribe rates as hereinbefore provided.

"(b) If any public utility does not have continuing property records, kept in the manner prescribed by the commission, under the provisions of section five hundred two of this act, then the commission, after reasonable notice and hearing, may establish temporary rates which shall be sufficient to provide a return of not less than an amount equal to the operating income for the year ending December thirty-first, one thousand nine hundred thirty-five, or such other subsequent year as the commission may deem proper, to be determined on the basis of data appearing in the annual report of such public utility to the commission for the year one thousand nine hundred thirty-five, or such other subsequent year as the commission may deem proper, plus or minus such return as the commission may prescribe from time to time upon such net changes of the physical property as are reported to and approved for rate-making purposes by the commission. In determining the net changes of the physical property, the commission may, in its discretion, deduct from gross additions to such physical property the amount charged to operating expenses for depreciation or, in lieu thereof, it may determine such net changes by deducting retirements from the gross additions: Provided, That the commission, in determining the basis for temporary rates, may make such adjustments in the annual report data as may, in the judgment of the commission, be necessary and proper."

n10 *Edison Light & Power Co.* v. *Driscoll*, 25 F.Supp. 192.

[***HR3] Appellee's first contention is that the decree may be sustained for the sole reason that the commission should have proceeded under subsection (b) because the appellee does not have continuing property records. As the conclusion of the lower court on this point is not supported by a state decision, we analyze for ourselves the provisions of the sections. It is clear from the language of § 310 (a) that it is applicable not only to public utilities whose reports to the commission show the original cost of their physical property but also to those whose original cost is not so shown. The last clause of the section authorizes the commission to estimate such cost. There is no provision in 310 (a) which limits its application to those utilities which maintain the continuing property records of § 502. n11 Section 310 (b), see note 9, furnishes a partial alternative for § 310 (a). Where there are no continuing property records, as provided by § 502, the commission must in fixing the temporary rate arrange for at least a [***1141] five per cent return on original cost under (a) or the return of an operating income under (b) equal to that for the year 1935 or a subsequent year, as determined by the commission.

n11 P. L. 1053, Purdon's Pa. Stat. Ann., 1938 Supp., Title 66, § 1212. "Continuing property records. -- The commission may require any public utility to establish, provide, and maintain as a part of its system of accounts, continuing property records, including a list or inventory of all the units of tangible property used or useful in the public service, showing the current location of such property units by definite reference to the specific land parcels upon which such units are located or stored; and the commission may require any public utility to keep accounts and records in such manner as to show, currently, the original cost of such property when first devoted to the public service, and the reserve accumulated to provide for the depreciation thereof."

[*113] Appellee urges next that the section permits the commission to disregard present cost, depreciate original cost, omit indirect and overhead items of construction, and exclude allowances for working capital or going concern value. Although these items were considered by the commission, the appellee contends that the order is invalid because § 310 (a) might have been complied with by providing a return of 5% on the original cost depreciated. The argument seems to be that a statute which permits an unconstitutional determination is invalid, even though it is actually applied in a constitutional manner. n12

n12 Cf. *Panama Refining Co.* v. *Ryan*, 293 U.S. 388, 420; *Wuchter* v. *Pizzutti*, 276 U.S. 13, 24; *People* v. *Klinck Packing Co.*, 214 N. Y. 121, 138; 108 N. E. 278; *Montana Company* v. *St. Louis Mining Co.*, 152 U.S. 160, 170. But see *Hatch* v. *Reardon*, 204 U.S. 152, 160; *Tyler* v. *Judges*, 179 U.S. 405, 410; *Jacobson* v. *Massachusetts*, 197 U.S. 11, 37; *Lieberman* v. *Van De Carr*, 199 U.S. 552, 562; *Home Telephone Co.* v. *Los Angeles*, 211 U.S. 265, 278.

The commission drew the order in accord with the prior ruling of the Middle District Court on a former order in this [**720] rate proceeding. n13 The former order had also fixed temporary rates but had not set out the findings of value deemed essential by the court. Although the reversal of the commission's order had actually turned on the failure to show the factual basis for the rates, as the district court had stated that compliance with *Smyth* v. *Ames* n14 was necessary in temporary rate making, the commission based the order now under review on evidence requisite under that rule. By taking this position, it interprets the statute as requiring consideration of elements other than original cost in fixing temporary rates. It is not suggested that the commission omitted consideration of any necessary element in the present order. If we assume with the appellee that the constitutionality of a [*114] delegation of rate making authority is to be tested by what a rate making body may rightfully do under the delegation rather than what it does, appellee's case is advanced not one whit. We have here an interpretation of the Pennsylvania statute by the board charged with its enforcement that it must weigh all the essential elements of valuation required by our past decisions.

n13 *Edison Light & Power Co.* v. *Driscoll*, 21 F.Supp. 1.

n14 169 U.S. 466.

[***HR4] There is nothing in the language of § 310 (a) which requires a different construction. The commission is authorized to fix temporary rates. There is no requirement as to how the rates are to be determined, except that they shall be sufficient to return a given minimum -- not less than 5% on the original cost, less depreciation. The language authorizing the fixing of temporary rates is cast, except as to the limitation just referred to, in much the same pattern as the language of § 309 authorizing the determination of permanent rates. The latter section reads: ". . . the commission shall determine the just and reasonable rates . . ." A different [***1142] construction would raise the novel and important question of the constitutionality of a temporary rate, based solely on depreciated original cost, with provision for recoupment of the loss from insufficient temporary rates. n15 In the absence of an [*115] authoritative state decision, we are reluctant to accept a construction which brings forward that issue, particularly when the case may reasonably be determined upon the interpretation of the officials of the state charged with the administration of the act. n16 This course observes the very salutary rule that "this Court will not decide an issue of constitutionality if the case may justly and reasonably be decided under a construction of the statute under which the act is clearly constitutional." n17

n15 "(e) Temporary rates so fixed, determined, and prescribed under this section shall be effective until the final determination of the rate proceeding, unless terminated sooner by the commission. In every proceeding in which temporary rates are fixed, determined, and prescribed under this section, the commission shall consider the effect of such rates in fixing, determining, and prescribing rates to be thereafter demanded or received by such public utility on final determination of the rate proceeding. If, upon final disposition of the issues involved in such proceeding, the rates as finally determined, are in excess of the rates prescribed in such temporary order, then such public utility shall be permitted to amortize and recover, by means of a temporary increase over and above the rates finally determined, such sum as shall represent the difference between the gross income obtained from the rates prescribed in such temporary order and the gross income which would have been obtained under the rates finally determined if applied during the period such temporary order was in effect." Cf. *Prendergast* v. *New York Telephone Co.*, 262 U.S. 43; *Bronx Gas & Electric Co.* v. *Maltbie*, 271 N. Y. 364; 3 N. E. 2d 512.

n16 *Fox* v. *Standard Oil Co.*, 294 U.S. 87, 97; *Union Ins. Co.* v. *Hoge*, 21 How. 35, 66.

n17 *Thompson* v. *Consolidated Gas Corp.*, 300 U.S. 55, 75-76, and cases cited; cf. *Blodgett* v. *Holden*, 275 U.S. 142, 148; *Federal Trade Comm'n* v. *American Tobacco Co.*, 264 U.S. 298, 307; *Texas* v. *Eastern Texas R. Co.*, 258 U.S. 204, 217.

Confiscation. -- There remains for examination the appellee's argument that the decree of the district court enjoining the enforcement [**721] of the order should be sustained because it is confiscatory. The commission, as of November 30, 1937, found the rate base, revenue, expenses and rate, as set out below. n18 Appellee urges here that the commission's figures are erroneous in the following particulars: (1) The rate base should be $ 5,866,081; (2) the rate should be 7 1/2 per cent; (3) two items of expense, disallowed by the commission should be added to the operating expenses, (a) some increase in annual salaries and (b) rate case expenses on books to November [*116] 15, 1937; (4) allowance should be made for a prospective loss of annual profit by reason of the loss of a large customer, through abandonment of railway service by York Railways Company.

n18

Rate Base or Fair Value of Property			$ 5,250,000.00
Rate of return 6%. Required return			315,000.00
Revenue after Reduction		$ 1,767,329.00	
Operating Expenses	$ 1,033,898.00		
Taxes	206,400.00		
Annual Depreciation	142,531.00	1,382,829.00	
Estimated Return			384,500.00

(1) The commission estimated the original cost as of December 31, 1936, at $ 4,576,169.73. The company estimated the original cost as of November 30, 1936, exclusive of financing charges, at $ 4,619,364.00 and its book cost as of December 31, 1936, at $ 4,578,793.00. If, to the highest of these items, we add $ 164,000 for working capital and $ 142,851.07, [***1143] representing net additions to September 30, 1937, the amounts claimed by the company, the original cost rate base is found to be not more than $ 4,926,215.07.

[***HR5] The commission excluded the cost of financing because there was no evidence of any actual expenditures for such purpose or of any studies of such cost. We find no error in this. n19 There was here no foundation for an estimate. n20 Appellee's suggestion that evidence supporting its claim is found in the capitalization chart of York Railways Company, the owner of appellee's common stock, is not accepted. This shows the discount, $ 298,825.00, paid by the parent company on $ 2,706,000 face amount of bonds of various issues between 1909 and 1925. It appears that $ 1,027,904 of the proceeds was expended for construction work of the York Edison Company, apparently appellee's predecessor. Nothing is shown as to the cost of this money to the appellee. It may have given notes for or been charged with this exact amount, without a finance charge. The financing cost to appellee may have been covered by the interest rate.

n19 *Wabash Valley Elec. Co.* v. *Young*, 287 U.S. 488, 500; *Galveston Electric Co.* v. *Galveston*, 258 U.S. 388, 397.

n20 Cf. *Dayton P. & L. Co.* v. *Comm'n*, 292 U.S. 290, 309-10; *Los Angeles Gas Co.* v. *Railroad Comm'n*, 289 U.S. 287, 310.

[*117]

[***HR6] The commission made no specific allowance for going concern value. It did, however, state that it had weighed the going concern value with other factors to determine fair value. It gave practical effect to this consideration when it fixed fair value several hundred thousand dollars in excess of its average of original and reproduction cost, both depreciated. In the computations by the company of original and reproduction costs, allowances were made for the overhead expense of creating the aggregate of land, buildings, and equipment, making up the utility. No tangible evidence of any unusual situation justifying any definite further allowance appears in the testimony of appellee's witness Seelye. The plant of the utility without the utilization of its production by the community would be of little value. Expenditures to secure customers through advertisement and solicitation, as well as to install connections do not appear separate from the ordinary operating and construction costs. The appellee points to the character of the territory served, the company's ability to earn, the efficiency of the management, the adequate available power supply and the excellent capital structure as indicative of a going concern value above tangible property plus overhead. To appraise these elements apart from and in addition to reasonable cost figures would require evidence of a failure on the part [**722] of the commission to give reasonable weight to these factors. This evidence is lacking here. n21

n21 *Denver Stock Yard Co.* v. *United States*, 304 U.S. 470, 478; *St. Joseph Stock Yards Co.* v. *United States*, 298 U.S. 38, 62. Cf. *Dayton P. & L. Co.* v. *Comm'n*, 292 U.S. 290, 308; *St. Joseph Stock Yards Co.* v. *United States*, 11 F.Supp. 322, 334; *Des Moines Gas Co.* v. *Des Moines*, 238 U.S. 153; *McCardle* v. *Indianapolis Co.*, 272 U.S. 400, 413.

[***HR7] For depreciated reproduction cost as of November 30, 1936, the commission accepted the estimate of the company for direct costs, $ 3,981,347. It added 19%, $ 756,456, [*118] for indirect costs and reached a total of $ 4,737,803. This finding reduced the indirect costs from the 24.3 per cent claimed by the company. Evidence was introduced before the commission supporting each percentage estimate. The amount of these indirect costs likely to be incurred is too uncertain for us to conclude [***1144] that the percentage adopted is erroneous. n22 We cannot see that the failure of the commission's witness Bierman to inspect the property made less valuable his estimate on the proper percentage to be applied for indirect costs. These indirect costs are of the character of interest, supervision, cost of financing, taxes and legal expense.

n22 *Dayton P. & L. Co.* v. *Comm'n*, 292 U.S. 290, 311.

The utility states that the commission, in fixing the reproduction cost, erred by refusing to consider the effect of a claimed increase of prices. The commission, on November 30, 1937, fixed reproduction cost upon a computation based by the utility upon prices as of November 30, 1936. This showed a gross cost of $ 5,572,134, depreciated and reduced by the commission, as explained in the preceding paragraph, to $ 4,737,803. The utility presented a further computation, showing as of May 31, 1937, that increased prices, due to a rising level, would increase the gross cost to $ 6,019,832. The argument is that the later estimate should have been considered. n23 Proportionally reduced to accord with the action of the commission, this latter figure would become $ 5,118,465. If to this higher reproduction cost we add working capital, there appears a reproduction cost depreciated figure of $ 5,282,465.

n23 *McCart* v. *Indianapolis Water Co.*, 302 U.S. 419.

It is furthermore to be observed that the commission's figures do not differ far as to fair value, from the estimate of an important witness for the utility, Mr. Seelye, who testified on March 12, 1937, that the fair value was not less than $ 5,500,000 and said later in answer to the commissioner's [*119] question that the fair value, in his opinion, was $ 5,500,000. This estimate was reiterated on December 20, 1937, in the affidavits of Mr. Seelye and Mr. Wayne, the President of the company, in support of the motion for temporary injunction.

For the purpose of passing upon the issue of confiscation in the temporary rates, we shall accept $ 5,500,000 as the fair value of the property as of November 30, 1937.

[***HR8] (2) The rate of return was fixed by the commission at six per cent. Witnesses for the utility brought out facts deemed applicable in the determination of a proper rate of return on the fair value of the property. Their evidence took cognizance of the yield of bonds, preferred and common stocks of selected comparable utilities, the stagnant market for new issues, prevailing cost of money, the implications of the possible substitution of some governmentally operated or financed utilities for those privately owned and the dangers of a fixed schedule of rates in the face of possible inflation. From these factors they deduced that a proper rate of return would be from 7.8 per cent to 8 per cent. An accounting expert of the commission countered with tables showing yields of bonds of utilities; the yield to maturity of Pennsylvania public utility securities, approved by the commission between July 1, 1933, and May 7, 1937, long term and actually sold for cash to non-affiliated interests; yield of Pennsylvania electric utilities; financial and operating statistics of Pennsylvania electric utilities; money rates, and other material information. He concluded 5.5 per cent was a reasonable rate of return.

[***HR9] It must be recognized that each utility presents an individual problem. n24 The answer does not lie alone in [*120] average [**723] yields of seemingly comparable securities [***1145] or even in deductions drawn from recent sales of issues authorized by this same commission. Yields of preferred and common stocks are to be considered, as well as those of the funded debt. When bonds and preferred stocks of well seasoned companies can be floated at low rates, the allowance of an over all rate return of a modest percentage will bring handsome yields to the common stock. Certainly the yields of the equity issues must be larger than that for the underlying securities. In this instance, the utility operates in a stable community, accustomed to the use of electricity and close to the capital markets, with funds readily available for secure investment. Long operation and adequate records make forecasts of net operating revenues fairly certain. Under such circumstances a six per cent return after all allowable charges cannot be confiscatory.

n24 *United Railways* v. *West*, 280 U.S. 234, 249; *Willcox* v. *Consolidated Gas Co.*, 212 U.S. 19, 48; *Bluefield Co.* v. *Public Service Comm'n*, 262 U.S. 679, 692; *Knoxville* v. *Water Co.*, 212 U.S. 1, 17.

[***HR10] (3) and (4). The utility urges that two items of expense and a prospective loss should be added to the operating expenses, allowed by the commission, of $ 1,382,829. The most important of these items is the rate case expenses. The company by its Exhibit 21 shows these incurred to November 15, 1937, to be $ 178,374.50. The commission from Exhibit 23 found them to be $ 127,935 for the twelve months ending September 30, 1937. The difference probably comes from the expenses before and after the period considered by the commission. We assume the higher figures to be correct. As the commission concluded that the prior rates of the company were obviously excessive, it allowed nothing for expense in defending them. Consequently there is no discussion of the reasonableness of the amount of the company's charge and we accept them as reasonable. Even where the rates in effect are excessive, on a proceeding by a commission to determine reasonableness, we are of the view that the utility should be allowed its fair and proper [*121] expenses for presenting its side to the commission. We do not refer to expense of litigation in the courts. "A different case would be here if the company's complaint had been unfounded or if the cost of the proceeding had been swollen by untenable objections." n25

n25 *West Ohio Gas Co.* v. *Comm'n* (No. 1), 294 U.S. 63, 74; see *Wabash Valley Elec. Co.* v. *Young*, 287 U.S. 488, 500.

[***HR11] In the allowance of these expenses, the period over which they are to be amortized will depend upon the character of services received or disbursements made. There could rarely be an anticipation of annually recurring charges for rate regulation. Under the circumstances here presented where full statistics on investment, inventory and labor requirements have been made which, as cumulated, will form largely the basis of all future negotiations, we are of the opinion that amortization over a ten year period is reasonable. n26 As such an adjustment produces an estimated return very close to the reasonable rate, even with the addition to the operating expenses of the other items of increased salaries, $ 20,593, and prospective loss of annual profit, $ 15,089, we do not enter into a discussion of them. Experience will add its weight to the other [***1146] evidence on further hearing. The note below shows the calculation. n27

n26 *Wabash Valley Elec. Co.* v. *Young*, 287 U.S. 488, 500; *West Ohio Gas Co.* v. *Comm'n* (No. 1), 294 U.S. 63, 74.

n27 Compare with the computation of the Commission, note 18.

Rate Base or Fair Value of Property			$ 5,500,000.00
Rate of return 6%. Required return			330,000.00
Revenue after Reduction		$ 1,767,329.00	
Operating Expenses	$ 1,033,898.00		
Taxes	206,400.00		
Annual Depreciation	142,531.00		
Rate Expense, 10-year Amortization	17,838.00		
Salary Increase	20,593.00		
Prospective Loss	15,089.00	1,436,349.00	
Estimated Return			330,980.00

At [**724] best, these estimates are prophecies of expected returns. The incalculable factors of business activity, unanticipated [*122] demand or forbearance, substitution and other variables lead us to approximations. We are satisfied the reduction required is not shown to be confiscatory.

Reversed.

CONCURBY:

FRANKFURTER

CONCUR:

MR. JUSTICE FRANKFURTER, concurring.

The decree below was clearly wrong. But in reversing it, the Court's opinion appears to give new vitality needlessly to the mischievous formula for fixing utility rates in *Smyth* v. *Ames*, 169 U.S. 466. The force of reason, confirmed by events, has gradually been rendering that formula moribund by revealing it to be useless as a guide for adjudication. Experience has made it overwhelmingly clear that *Smyth* v. *Ames* and the uses to which it has been put represented an attempt to erect temporary facts into legal absolutes. The determination of utility rates -- what may fairly be exacted from the public and what is adequate to enlist enterprise -- does not present questions of an essentially legal nature in the sense that legal education and lawyers' learning afford peculiar competence for their adjustment. These are matters for the application of whatever knowledge economics and finance may bring to the practicalities of business enterprise. The only relevant function of law in dealing with this intersection of government and enterprise is to secure observance of those procedural safeguards in the exercise of legislative powers which are the historic foundations of due process.

Mr. Justice Bradley nearly fifty years ago made it clear that the real issue is whether courts or commissions and legislatures are the ultimate arbiters of utility rates, (dissenting, in *Chicago, M. & St. P. Ry. Co.* v. *Minnesota*, 134 U.S. 418, 461). Whatever may be thought of the wisdom of a broader judicial role in the controversies between public utilities and the public, there can be no [*123] doubt that the tendency, for a time at least, to draw fixed rules of law out of *Smyth* v. *Ames* has met the rebuff of facts. At least one important state has for decades gone on its way unmindful of *Smyth* v. *Ames*, and other states have by various proposals sought to escape the fog into which speculations based on *Smyth* v. *Ames* have enveloped the practical task of administering systems of utility regulation.

Smyth v. *Ames* should certainly not be invoked when it is not necessary to do so. The statute under which the present case arose represents an effort to escape *Smyth* v. *Ames* at least as to temporary rates. It is the result of a conscientious and informed endeavor to meet difficulties engendered by legal doctrines which have been widely rejected by the great weight of economic opinion, n1 by authoritative legislative investigations, n2 by utility [***1147] commissions throughout the country, n3 and by impressive judicial dissents. n4 As a result of this long process of experience and reflection, the two states in which utilities play the biggest financial part -- New York and Pennsylvania -- have evolved the so-called recoupment scheme for temporary rate-fixing (thereby avoiding some of the most [*124] wasteful aspects of rate litigation) as a fair means of accommodating public and private interests. It is a carefully guarded device for securing "a judgment from experience as against a judgment from speculation," *Tanner* v. *Little*, 240 U.S. 369, 386, in dealing with a problem of such elusive economic complexity [**725] as the determination of what return will be sufficient to attract capital in the special setting of a particular industry and at the same time be fair to the public dependent on such enterprise.

n1 See 2 BONBRIGHT, THE VALUATION OF PROPERTY, 1081-1086, 1094-1102; 3A SHARFMAN, THE INTERSTATE COMMERCE COMMISSION, 121-137.

n2 N. Y. State Commission on Revision of the Public Service Commission Law, *Report of Commissioners, passim* (1930).

n3 Proceedings of the Forty-Seventh Annual Convention of the National Association of Railroad and Utilities Commissioners, 232 *et seq.*; Proceedings of the Forty-Eighth Annual Convention of the National Association of Railroad and Utilities Commissioners, 115 *et seq.*, 289 *et seq.*; Proceedings of the Forty-Ninth Annual Convention of the National Association of Railroad and Utilities Commissioners, 159 *et seq.*

n4 See, e. g., Brandeis, J., concurring, in *Missouri ex rel. Southwestern Bell Telephone Co.* v. *Public Service Comm'n*, 262 U.S. 276, 289, and bibliography therein contained.

That this Court should not "decide an issue of constitutionality if the case may justly and reasonably be decided under a construction of the statute under which the act is clearly constitutional" is, as an abstract proposition, basic to our judicial obligation. But this is not a formal doctrine of self-restraint. Its rationale is avoidance of conflict with the legislature. The opinion from which the preceding quotation is taken and the decisions to which it refers are all cases in which constitutionality was in obvious jeopardy. It is one thing to avoid unconstitutionality even at the cost of a tortured statutory construction. It is quite another to recognize the validity of a statute directed expressly to the situation in hand and so employed by the state authorities, when constitutionality of that statute is as incontestably clear as the decision of the New York Court of Appeals has demonstrated it to be in sustaining the sister statute of the Pennsylvania Act, *In the Matter of Bronx Gas & Electric Co.* v. *Maltbie*, 271 N. Y. 364; 3 N. E. 2d 512. The Court's opinion in the present case does not avoid issues of constitutionality. It accepts the much more dubious constitutional doctrines of *Smyth* v. *Ames* and its successors to solve the very easy constitutional issues raised by the Pennsylvania Act.

MR. JUSTICE BLACK concurs in the above views.

REFERENCES: Return To Full Text Opinion

Tab B

294 U.S. 63, *; 55 S. Ct. 316, **;
79 L. Ed. 761, ***; 1935 U.S. LEXIS 37

WEST OHIO GAS CO. v. PUBLIC UTILITIES COMMISSION OF OHIO (No. 1)

No. 212

SUPREME COURT OF THE UNITED STATES

294 U.S. 63; 55 S. Ct. 316; 79 L. Ed. 761; 1935 U.S. LEXIS 37

December 7, 1934, Submitted
January 7, 1935, Decided

PRIOR HISTORY:

APPEAL FROM THE SUPREME COURT OF OHIO.

APPEAL from the affirmance of an order of the Public Utilities Commission fixing the rates of the Gas Company in the City of Lima, Ohio.

DISPOSITION:

128 Ohio St. 301; 191 N. E. 105, reversed.

CORE TERMS: ordinance, rate base, allowance, spread, operating expenses, confiscation, cubic feet, customer, valuation, new business, rate of return, expenditure, reduction, ascertained, duration, judicial notice, natural gas, fair return, new method, rate case, wasteful, consumers, warning, struck, annual, notice, fixing, Fourteenth Amendment, public service, entire period

LexisNexis(R) Headnotes

SYLLABUS:

1. In computing the operating expenses of a gas-distributing company, in the process of fixing its rates, the company's books are presumptively correct. P. 67.

2. Where the company's accounts showed that the amount of gas lost through leakage, etc., was 9% per annum of the amount purchased by it, and the books were found regular, but the public commission, in fixing its rates, struck off 2% of this from operating expense, upon the ground that with proper care the loss would have been less, and did so without any evidence of waste or neglect, and without giving to the company any warning of this action or opportunity to oppose it by proof of due care, -- *held* that the action was wholly arbitrary. P. 67.

3. Where the sole method provided by state law for review of a rate-fixing order is by hearing upon the law and facts on an appeal to the state supreme court, the facts relied on to sustain the rates against unimpeached evidence submitted by the utility must be exhibited in the record, otherwise the hearing is inadequate and not judicial. P. 68.

4. In fixing rates of a gas company, a public commission, after closing the hearings and without further notice to the company, adopted a new method of distributing certain expenses over the area served and applied it to one city, where its effect on the rate was unfavorable to the company, and omitted to apply it to another where the effect would have been favorable. The reallocation was based on the commission's construction of annual reports of the company which had not been put in evidence, and no opportunity was allowed to contest the reallocation or to secure a rate readjustment in harmony with it. *Held* that the procedure was unfair and contrary to due process. Pp. 69, 71.

5. In reviewing rate cases coming from state courts, under the due process clause, the function of this Court is not concerned with error or irregularity in the rate-making, however gross, if the consequences, in their totality, are consistent with enjoyment by the regulated utility of a revenue something higher than the line of confiscation, and if suitable opportunity was afforded the utility through evidence and argument to challenge the result. P. 70.

6. In deciding a rate case the Court may take judicial notice of the record of a similar and related case pending before it between the same parties. P. 70.

7. Within the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes; and a refusal by a public commission to make allowance for such expenditures, on the ground that they were excessive and wasteful but without any evidence to support it, is contrary to due process. P. 72.

8. Good faith on the part of the managers of a business is to be presumed; and in the absence of a

showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay. P. 72.

9. Judicial notice is taken of the fact that gas is in competition with other fuels, such as oil or electricity. P. 72.

10. Rates fixed by city ordinance for a term of years were set aside as unfair and higher rates substituted for the same term in a proceeding brought before a public commission by the utility affected. *Held* that, in determining whether the higher rates yield a fair return, the amount reasonably laid out by the utility as expenses of the proceeding, including the charges of engineers and counsel, should be included in the costs of operation and spread over the period for which the rates were prescribed. P. 72.

11. As applied to a corporation engaged in the sale of gas during 1928-1931, compulsory rates which net an income of only 4.53% upon its proper rate base, are confiscatory. P. 75.

12. The claim made by the Gas Company that the allowance for depreciation reserve was inadequate, and that it was entitled to add to operating charges the amortized value of a transmission main extending from the city to fields of natural gas, cannot be upheld. P. 77.

COUNSEL:

Messrs. Edmond W. Hebel, Harry O. Bentley, and Charles C. Marshall submitted for appellant.

Mr. John W. Bricker, Attorney General of Ohio, and Mr. Donald C. Power, Assistant Attorney General, submitted for appellee.

JUDGES:

Hughes, Van Devanter, McReynolds, Brandeis, Sutherland, Butler, Stone, Roberts, Cardozo

OPINIONBY:

CARDOZO

OPINION:

[*65] [**318] [***766] MR. JUSTICE CARDOZO delivered the opinion of the Court.

The appellant, West Ohio Gas Company, supplies gas to the inhabitants of the city of Lima, Ohio, and to neighboring communities, part of what it sells being artificial gas manufactured by itself and part natural gas bought from another company which is wholly independent.

On March 19, 1928, the municipal authorities of the city of Lima passed an ordinance, effective April 19, prescribing the maximum price to be charged for gas to consumers within the city during a period of five years. The rates were to be as follows: for the first 1,000 cubic feet of gas, 90 cents per month; for the next 3,000 cubic [*66] feet per month, 80 cents per M c. f.; for the next 6,000, 75 cents per M c. f.; and for all over 10,000 per month, 55 cents per M c. f. This was a sharp reduction of the rates previously charged, which were $ 1.25 for the first 400 cubic feet; $ 1.05 for the next 9,600 cubic feet; $ 1 for the next 15,000; and for all over 25,000, 75 cents per M c. f.

In adherence to the Ohio statutes (Ohio General Code, § § 614-44 *et seq.*), the company filed a complaint with the Public Utilities Commission of Ohio, protesting against the ordinance, praying that the commission fix a fair and reasonable schedule, electing, as it might, to charge in the meantime the rates previously in force, and giving bond for the return of the excess, if any. The hearings before the Commission began in July, 1928, and ended in July, 1932. While the proceeding was pending, there was a final order of valuation, made in January, 1932, whereby the value of the property in Lima, used and useful for the business, was fixed at $ 1,901,696.26 as of March 31, 1928, approximately the date of the adoption of the ordinance. There being no appeal from that order within the time prescribed by law, it became binding on the company, as well as on the commission, though the valuation was less than the company had urged. 128 Ohio St. 301, 311; 191 N. E. 105. The rate base being thus established, what was next to be ascertained was the amount of the operating expenses as compared with the gross income, after which a conclusion could be drawn as to the rates that would be necessary for a fair return on the [***767] investment. An order entered by the commission on March 10, 1933, adjudged the rates under the ordinance to be insufficient and unjust. It substituted rates averaging about 13 1/2% less than those that the company had been charging: for 400 cubic feet or less per month, $ 1; for the next 9,600, 95 cents per M c. f.; for anything in excess of [**319] 10,000 cubic feet per month, 75 [*67] cents per M c. f., with penalties to be charged if payment was delayed. The rates so fixed were to be retroactive as of the effective date of the ordinance, April 19, 1928, from which time they were to remain in force for a term of five years, and the difference between their yield and the amount collected by the company was to be refunded to consumers. A motion for a rehearing having been denied, the company filed a petition in error with the Supreme Court of Ohio, invoking the protection of the Fourteenth Amendment. The order of the commission was affirmed, 128 Ohio St. 301; 191 N. E. 105; and the case is here upon appeal.

The commission made its order, as it has informed us by an amended opinion, in the belief that the new rates would yield a return of 6.65% on the value of the property included in the base. Its estimate was wide of the mark as a result of mathematical errors, and this on the assumption that its rulings as to the items of operating expenses to be allowed or disallowed were correct in fact and law. Even on that assumption, the average net income during the four years of the ordinance period for which figures were available was $ 109,414, which upon a rate base of $ 1,901,696 is equivalent to an average return of about 5.75%. This is now admitted by counsel for the commission, and must be accepted as a datum. What is still to be determined is whether the rate of return has been further overestimated to the point of confiscation through error in the rejection of charges upon income.

[***HR1] [***HR2] 1. The company made claim to an allowance for "unaccounted for gas," which is gas lost as a result of leakage, condensation, expansion or contraction. There is no dispute that a certain loss through these causes is unavoidable, no matter how carefully the business is conducted. Cf. *Consolidated Gas Co.* v. *Newton*, 267 Fed. 231, 244; *Brooklyn Union Gas Co.* v. *Prendergast*, 7 F.2d 628, 652, 671. The company, basing its claim upon its [*68] proved experience, reported the average loss as 9% per annum. The Commission fixed the allowance at 7%, thereby reducing the operating expenses by $ 3,800 a year. In making this reduction, it did not deny that the loss had been suffered to the extent stated by the company. The presumption of correctness that gives aid in controversies of this order to the books of public service corporations (*Consolidated Gas Co.* v. *Newton, supra*, at p. 242; *Newton* v. *Consolidated Gas Co.*, 258 U.S. 165, 176) was confirmed in this instance by what amounts to a finding of regularity. Accepting the loss as proved, the commission refused to allow it for more than 7% upon the ground that with proper care of the system the loss would have been less. A public utility will not be permitted to include negligent or wasteful losses among its operating charges. The waste or negligence, however, must be established by evidence of one kind or another, either direct or circumstantial. In all the pages of this record. there is neither a word nor a circumstance to charge the management with fault. Cf. *Ohio Utilities Co.* v. *Public Utilities Commission of Ohio*, 267 U.S. 359, 363. There is not even the shadow of a warning to the company that fault was imputed and that it must give evidence of care. Without anything to suggest that there was such an issue in the case, the commission struck off 2%; it might with as much reason have struck off 4 or 6. This was wholly [***768] arbitrary. *Ohio Utilities Co.* v. *Public Utilities Commission of Ohio, supra.*

Under the statutes of Ohio no provision is made for a review of the order of the Commission by a separate or independent suit. The sole method of review is by petition in error to the Ohio Supreme Court, which considers both the law and the facts. *Dayton P. & L. Co.* v. *P. U. Commission of Ohio*, 292 U.S. 290, 302; *Hocking Valley Ry. Co.* v. *Public Utilities Commission*, 100 Ohio St. 321, 326, 327; 126 N. E. 397. To make such review adequate [*69] the record must exhibit in some way the facts relied upon by the court to repel unimpeached evidence submitted for the company. If that were not so, a complainant would be helpless, for the inference would always be possible that the court and the Commission had drawn upon undisclosed sources of information unavailable to others. A hearing is not judicial, at least in any adequate sense, unless the evidence can be known.

2. The company made claim to an allowance of "distribution expenses" incurred in the superintendence of distribution, in work on the premises of customers incidental to the service, in the change of meters used to measure the gas sold, and in the maintenance of local mains and equipment. There is no denial, even now, that these expenses were incurred [**320] as claimed. There was no challenge upon the trial to the practice of the company whereby moneys spent in Lima, the territorial unit affected by the ordinance, were allocated to that city. and not to territory beyond. The case was tried on the assumption that the practice was acceptable and was so submitted for decision. Eight months later, on the eve of a determination, the commission conceived the thought that distribution costs in Lima should be borne also by consumers in outlying communities (including the city of Kenton) served by the same company, which would mean, of course, that like expenses in the other communities must be borne by residents of Lima. Up to that stage the data were lacking for a division on that basis. Accordingly, by an order made *ex parte* on March 8, 1933, without the appellant's knowledge, the commission directed of its own motion that the annual reports for the years 1928 to 1931 inclusive be introduced in evidence and made a part of the record. On the basis of these reports it ascertained the average distribution expense per customer for all the eleven communities served by the appellant, multiplied this average by the number [*70] of customers in Lima, and thus arrived at the share to be allocated to that city in the determination of the local rates. By that mode of apportionment, the operating expenses were reduced to the extent of $ 6,200 annually.

[***HR3] [***HR4] We do not now decide that there would be a denial of due process through the spread of distributing costs over the total area of service, if the new method of allocation had been adopted after timely notice to the company and then consistently applied. This court does not sit as a board of revision with power to review the action of administrative agencies upon grounds unrelated to the maintenance of constitutional immunities. *Los Angeles Gas & Electric Corp.* v. *Railroad Commission of California*, 289 U.S. 287. Our inquiry in rate cases coming here from the state courts is whether the action of the state officials in the totality of its consequences is consistent with the enjoyment by the regulated utility of a revenue something higher than the line of confiscation. If this level is attained, and attained with suitable opportunity through evidence and argument (*Southern Ry. Co.* v. *Virginia*, 290 U.S. 190) to challenge the result, there is no denial of due process, though the proceeding is shot through with irregularity or error. But the weakness of the case for the [***769] appellee is that the fundamentals of a fair hearing were not conceded to the company. Opportunity did not exist to supplement or explain the annual reports as to the distribution of the expenses in the neighboring communities, nor did opportunity exist to bring the rates outside of Lima into harmony with the exigencies of a new method of allocation adopted without warning.

[***HR5] The need for such an opportunity is brought into clear relief by the record in number 213, a case submitted along with this one, and within the range of our judicial notice. *Butler* v. *Eaton*, 141 U.S. 240, 243, 244; *Aspen Mining & Smelting Co.* v. *Billings*, 150 U.S. 31, 38; *Bienville* [*71] *Water Supply Co.* v. *Mobile*, 186 U.S. 212, 217; *Fritzlen* v. *Boatmen's Bank*, 212 U.S. 364, 370. The subject matter of that case was the rate schedule for the city of Kenton, served with gas by the appellant. In Kenton, unlike Lima, a spread of distribution costs over the whole area of service would have been favorable to the appellant and unfavorable to customers. Strange to say, the commission, though prescribing the larger area for Lima, adopted the smaller one for Kenton, and this by a decision rendered the same day. An injustice so obvious may not be suffered to prevail. The commission by its counsel suggests as an excuse that a division on a different basis was not requested by the company. There was no reason to request it, for the record as made up when the case was finally submitted did not contain the necessary data for a spread over a larger area, nor was there any hint by the commission that such a division was in view. Manifestly, whatever territorial unit is adopted must be made use of consistently, and regardless of the consequences. If a different course were to be followed, there would be less than full requital after all the communities affected had contributed their quotas.

[***HR6] To resume: division on one basis in Lima and on another basis in Kenton, all without notice to the company that the spread was to be altered and new evidence received, was an exercise of arbitrary power, at variance with "the rudiments of fair play" (*Chicago, M. & St. P. Ry. Co.* v. *Polt*, 232 U.S. 165, 168) long known to our law. The Fourteenth Amendment [**321] condemns such methods and defeats them.

3. The company made claim to commercial expenses incurred in reading the meters of the customers, keeping their accounts, and sending out and collecting bills. The commission treated these items the same way that it treated the expenses of distribution, and spread them over the whole territory instead of confining them to Lima. The result was a reduction of operating expenses [*72] to the extent of $ 1,085.25 yearly. For reasons already stated, the reduction may not stand.

[***HR7] [***HR8] 4. The company made claim to expenses incurred in procuring new business or in the endeavor to procure it, such expenses amounting on the average to $ 12,000 a year. The commission did not question the fact of payment, but cut down the allowance to $ 5,000 a year on the ground that anything more was unnecessary and wasteful. The criticism has no basis in evidence, either direct or circumstantial. Good faith is to be presumed on the part of the managers of a business. *Southwestern Bell Telephone Co.* v. *Public Service Commission of Missouri*, 262 U.S. 276, 288, 289. In the absence of a showing of inefficiency or improvidence, a court will not substitute its judgment for theirs as to the measure of a prudent outlay. *Banton* v. *Belt Line Ry. Corp.*, 268 U.S. 413, 421; *Brooklyn Borough Gas* [***770] *Co.* v. *Prendergast*, 16 F.2d 615, 623; *New York & Richmond Gas Co.* v. *Prendergast*, 10 F.2d 167, 181. The suggestion is made that there is no evidence of competition. We take judicial notice of the fact that gas is in competition with other forms of fuel, such as oil and electricity. A business never stands still. It either grows or decays. Within the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes as for others. *Consolidated Gas Co.* v. *Newton, supra*, at p. 253. When a business disintegrates, there is damage to the stockholders, but damage also to the customers in the cost or quality of service.

5. The company made claim to an allowance of the expenses of the rate litigation amounting in all to about $ 30,000, to be spread in equal parts over a term of five years, the duration of the ordinance. No part of these expenses has been allowed, though apparently both commission and court intended to allow them, spreading them, however, over a term of six years instead of five. "It [*73] must be conceded," said the court, "that the gas company is entitled to a fair and reasonable allowance for rate case expenses." This is followed by the statement that if the spread be six years (instead of five), and $ 5,100 be allowed for each of those years "as contended by the commission," the rate fixed by the order will give an

adequate return. True there is also the statement that the commission would have been warranted in ignoring this item altogether "in the absence of proof that the gas company's book figures represented an amount that was fair and reasonable." Even in that remark the implication is obvious that this is not what the commission did. Moreover, there is nothing in the record justifying an inference that the figures were erroneous or the payments improvident. *Consolidated Gas Co.* v. *Newton, supra*, at p. 242; *Newton* v. *Consolidated Gas Co., supra*, at p. 176. The course of the trial exhibits very clearly the understanding of the parties that expenditures shown by the books would be deemed to have been made in good faith and with reasonable judgment unless evidence was at hand overcoming the presumption. In the absence of any challenge of their necessity or fairness, we must view them as they were accepted by the triers of the facts.

[***HR9] Thus viewing them, we think they must be included among the costs of operation in the computation of a fair return. The company had complained to the Commission that an ordinance regulating its rates was in contravention of the statutes of the state and of the Constitution of the nation. In that complaint it prevailed. The charges of engineers and counsel, incurred in defense of its security and perhaps its very life, were as appropriate and even necessary as expenses could well be.

A different case would be here if the company's complaint had been unfounded, or if the cost of the proceeding had been swollen by untenable objections. There is neither evidence nor even claim that the conduct of the company's representatives was open to that reproach. [*74] The statute laid a duty on the commission, when it found the ordinance unjust, to prescribe its own schedule. The one it adopted, though higher than the one condemned, did not satisfy the company, but there was nothing unreasonable or obstructive [**322] in laying before the commission whatever data might be helpful to that body in reaching a considered judgment. Indeed, we shall be brought to the conclusion, if we analyze the record, that the two phases of the controversy were substantially coincident. Everything relevant to the schedule adopted by the commission was relevant also to an inquiry into the fairness of the ordinance.

In this matter of rate case expenses, [***771] we must distinguish between the function of a court and that of a commission. A court passing upon a challenge to the validity of statutory rates does not determine the rates to be adopted as a substitute. *Central Kentucky Natural Gas Co.* v. *Railroad Commission of Kentucky*, 290 U.S. 264, 271, 272; *Newton* v. *Consolidated Gas Co., supra*. If the rates are inadequate to the point of confiscation, the complainant has no need, it is said, to count upon the expenses of the lawsuit; if they are not already inadequate, the lawsuit cannot make them so. Cf. *Columbus Gas & Fuel Co.* v. *City of Columbus*, 17 F.2d 630, 640. An argument to that effect runs through some of the decisions, though we are not required now either to accept or to reject it. But the case is different where a commission, after setting a schedule of rates aside, is empowered to substitute another to take effect by retroaction and cover the same years. In determining what the substitute shall be, the commission must give heed to all legitimate expenses that will be charges upon income during the term of regulation, and in such a reckoning the expenses of the controversy engendered by the ordinance must have a place like any others. *Denver Union Stockyard Co.* v. *United States*, 57 F.2d 735, 753, 754; *New York & Richmond Gas Co.* v. *Prendergast, supra*, at pp. 181, 182; [*75] *Monroe Gas Light Co.* v. *Michigan Public Utilities Commission*, 11 F.2d 319, 325.

There are suggestions in the books that the cost of litigation is to be reckoned as an extraordinary expense and so a charge upon capital rather than a charge upon income to be paid out of the revenues of one year or of many. Cf. *New York & Queens Gas Co.* v. *Newton*, 269 Fed. 277, 290; *Reno P. L. & W. Co.* v. *Public Service Commission*, 298 Fed. 790, 801; *contra, New York & Richmond Gas Co.* v. *Prendergast, supra*, at pp. 181, 182; *Mobile Gas Co.* v. *Patterson*, 293 Fed. 208, 224. There is no need to consider what practice is to be followed where the rate is prescribed for a period of indefinite duration, though there would seem to be little difficulty in amortizing the charge over a reasonable term. Cf. *New York & Richmond Gas Co.* v. *Prendergast, supra*. In the case at hand, the period of duration has been definitely fixed, and the charge upon the income can be distributed accordingly.

We conclude that an addition of $ 5,100 must be made to the yearly operating expenses as the cost of proceedings necessary to keep the business going. Cf. *Kornhauser* v. *United States*, 276 U.S. 145. The company makes no point as to the ruling of the commission that the cost should be spread over six years instead of five, and we follow that concession.

[***HR10] 6. The items enumerated in subdivisions 1 to 5 of this opinion amount altogether to $ 23,185.25 annually. Added to the operating charges they reduce the net income from $ 109,414 to $ 86,228.75, or about 4.53% upon the rate base of $ 1,901,696. This is too low a rate to satisfy the requirements of the Constitution when applied to a corporation engaged in the sale of gas during the years 1928 to 1931, two at least of the four years being before the days of the depression. *Los Angeles Gas & Electric Co.* v. *Railroad Commission of California, supra*, at pp. 319, 320; *Dayton Power & Light Co.* v. [*76] *Public* least three of the five years are those of declining prices and diminishing capital returns. Since the commission's order was based on known income for four of the five years, the possibly lowered revenues of the fifth year cannot be taken to off-set the effect of the declining prices and capital returns. The record gives no hint of what the rate base would be were it ascertained for the entire period. While the Commission and the Ohio courts are bound to adopt a rate base determined as of the beginning of the ordinance period, this does not relieve the company [*79] of the burden of showing that the value [**324] of the property for the entire period is such that the net return under the Commission's rates would have been so low as to confiscate its property. See *Los Angeles Gas & Electric Corp.* v. *Railroad Commission*, 289 U.S. 287, 304. No contention is made that the Ohio procedure precludes such proof or that it prevented petitioner from showing facts which would establish confiscation.

REFERENCES: Return To Full Text Opinion

Tab C

N.J. Rev. Stat. § 48:3-49. Short title

Sections 1 through 46, and sections 51, 57, 59, 60, 63, 65 and 66 of this act shall be known and may be cited as the "Electric Discount and Energy Competition Act."

N.J. Rev. Stat. 48:3-50. Legislative findings

a. The Legislature finds and declares that it is the policy of this State to:

(1) Lower the current high cost of energy, and improve the quality and choices of service, for all of this State's residential, business and institutional consumers, and thereby improve the quality of life and place this State in an improved competitive position in regional, national and international markets;

(2) Place greater reliance on competitive markets, where such markets exist, to deliver energy services to consumers in greater variety and at lower cost than traditional, bundled public utility service;

(3) Maintain adequate regulatory oversight over competitive purveyors of retail power and natural gas supply and other energy services to assure that consumer protection safeguards inherent to traditional public utility regulation are maintained, without unduly impeding competitive markets;

(4) Ensure universal access to affordable and reliable electric power and natural gas service;

(5) Maintain traditional regulatory authority over non-competitive energy delivery or other energy services, subject to alternative forms of traditional regulation authorized by the Legislature;

(6) Ensure that rates for non-competitive public utility services do not subsidize the provision of competitive services by public utilities;

(7) Provide diversity in the supply of electric power throughout this State;

(8) Authorize the Board of Public Utilities to approve alternative forms of regulation in order to address changes in technology and the structure of the electric power and gas industries; to modify the regulation of competitive services; and to promote economic development;

(9) Prevent any adverse impacts on environmental quality in this State as a result of the introduction of competition in retail power markets in this State;

(10) Ensure that improved energy efficiency and load management practices, implemented via marketplace mechanisms or State-sponsored programs, remain part of this State's strategy to meet the long-term energy needs of New Jersey consumers;

(11) Preserve the reliability of power supply and delivery systems as the marketplace is transformed from a monopoly to a competitive environment; and

(12) Provide for a smooth transition from a regulated to a competitive power supply marketplace, including provisions which afford fair treatment to all stakeholders during the transition.

b. The Legislature further finds and declares that:

(1) In a competitive marketplace, traditional utility rate regulation is not necessary to protect the public interest and that competition will promote efficiency, reduce regulatory delay, and foster productivity and innovation;

(2) Due to regulatory changes, technological developments and other factors, a competitive electric generation and wholesale supply market has developed over the past several years;

(3) Electric power services are available in the wholesale markets at prices substantially lower than the current cost of electric power generation and supply services provided to retail customers by this State's electric public utilities;

(4) The traditional retail monopoly which electric public utilities have held in this State for electric power generation and supply services should be eliminated, so that all New Jersey energy consumers will be afforded the opportunity to access the competitive market for such services and to select the electric power supplier of their choice;

(5) The traditional electric public utility rate regulation which the Board of Public Utilities has exercised over retail power supply in this State requires reform in order to provide retail choice and bring the benefits of competition to all New Jersey consumers;

(6) Permitting the competitive electric power generation and supply marketplace to operate without traditional utility rate regulation will produce a wider selection of services at competitive market-based prices;

(7) Certain regulatory authority, including requiring electric power suppliers and gas suppliers to maintain offices in this State, is necessary to ensure continued safety, reliability and consumer protections in the electric power and gas industries; and to ensure accessibility to electric power suppliers and gas suppliers by the Board of Public Utilities, consumers, electric public utilities and gas public utilities; and

(8) The electric power generation marketplace and gas supply marketplace should be subject to appropriate consumer protection standards that will ensure that all classes of customers in all regions of this State are properly and adequately served.

c. The Legislature therefore determines that it is in the public interest to:

(1) Authorize the Board of Public Utilities to permit competition in the electric generation and gas marketplace and such other traditional utility areas as the board determines, and thereby reduce the aggregate energy rates currently paid by all New Jersey consumers;

(2) Provide for regulation of new market entrants in the areas of safe, adequate and proper service and customer protection;

(3) Relieve electric public utilities from traditional utility rate regulation in the provision of services which are deemed to be provided in a competitive market;

(4) Provide each electric public utility the opportunity to recover above-market power generation and supply costs and other reasonably incurred costs associated with the restructuring of the electric industry in New Jersey, the level of which will be determined by the Board of Public Utilities to the extent necessary to maintain the financial integrity of the electric public utility through the transition to competition, subject to the achievement of the other goals and provisions of this act, and subject to the public utility having taken and continuing to take all reasonably available steps to mitigate the magnitude of its above-market electric power generation and supply costs; and

(5) Provide the Board of Public Utilities with ongoing oversight and regulatory authority to monitor and review composition of the electric generation and retail power supply marketplace in New Jersey, and to take such actions as it deems necessary and appropriate to restore a competitive marketplace in the event it determines that one or more suppliers are in a position to dominate the marketplace and charge anti-competitive or above-market prices.

N.J. Rev. Stat. § 48:3-51. Definitions

As used in this act:

"Assignee" means a person to which an electric public utility or another assignee assigns, sells or transfers, other than as security, all or a portion of its right to or interest in bondable transition property. Except as specifically provided in this act, an assignee shall not be subject to the public utility requirements of Title 48 or any rules or regulations adopted pursuant thereto;

"Basic gas supply service" means gas supply service that is provided to any customer that has not chosen an alternative gas supplier, whether or not the customer has received offers as to competitive supply options, including, but not limited to, any customer that cannot obtain such service for any reason, including non-payment for services. Basic gas supply service is not a competitive service and shall be fully regulated by the board;

"Basic generation service" means electric generation service that is provided, pursuant to section 9 of this act, to any customer that has not chosen an alternative electric power supplier, whether or not the customer has received offers as to competitive supply options, including, but not limited to, any customer that cannot obtain such service from an electric power supplier for any reason, including non-payment for services. Basic generation service is not a competitive service and shall be fully regulated by the board;

"Basic generation service transition costs" means the amount by which the payments by an electric public utility for the procurement of power for basic generation service and related ancillary and administrative costs exceeds the net revenues from the basic generation service charge established by the board pursuant to section 9 of P.L.1999, c. 23 (C.48:3-57) during the transition period, together with interest on the balance at the board-approved rate, that is reflected in a deferred balance account approved by the board in an order addressing the electric public utility's unbundled rates, stranded costs, and restructuring filings pursuant to P.L.1999, c. 23 (C.48:3-49 et al.). Basic generation service transition costs shall include, but are not limited to, costs of purchases from the spot market, bilateral contracts, contracts with non-utility generators, parting contracts with the purchaser of the electric public utility's divested generation assets, short-term advance purchases, and financial instruments such as hedging, forward contracts, and options. Basic generation service transition costs shall also include the payments by an electric public utility pursuant to a competitive procurement process for basic generation service supply during the transition period, and costs of any such process used to procure the basic generation service supply;

"Board" means the New Jersey Board of Public Utilities or any successor agency;

"Bondable stranded costs" means any stranded costs or basic generation service transition costs of an electric public utility approved by the board for recovery pursuant to the provisions of this act, together with, as approved by the board: (1) the cost of retiring existing debt or equity capital of the electric public utility, including accrued interest, premium and other fees, costs and charges relating thereto, with the proceeds of the financing of bondable transition property; (2) if requested by an electric public utility in its application for a bondable stranded costs rate order, federal, State and local tax liabilities associated with stranded costs recovery or basic generation service transition cost recovery or the transfer or financing of such property or both, including taxes, whose recovery period is modified by the effect of a stranded costs recovery order, a bondable stranded costs rate order or both; and (3) the costs incurred to issue, service or refinance transition bonds, including interest, acquisition or redemption premium, and other financing costs, whether paid upon issuance or over the life of the transition bonds, including, but not limited to, credit enhancements, service charges, overcollateralization, interest rate cap, swap or collar, yield maintenance, maturity guarantee or other hedging agreements, equity investments, operating costs and other related fees, costs and charges, or to assign, sell or otherwise transfer bondable transition property;

"Bondable stranded costs rate order" means one or more irrevocable written orders issued by the board pursuant to this act which determines the amount of bondable stranded costs and the initial amount of transition bond charges authorized to be imposed to recover such bondable stranded costs, including the costs to be financed from the proceeds of the transition bonds, as well as on-going costs associated with servicing and credit enhancing the transition bonds, and provides the electric public utility specific authority to issue or cause to be issued, directly or indirectly, transition bonds through a financing entity and related matters as provided in this act, which order shall become effective immediately upon the written consent of the related electric public utility to such order as provided in this act;

"Bondable transition property" means the property consisting of the irrevocable right to charge, collect and receive, and be paid from collections of, transition bond charges in the amount necessary to provide for the full recovery of bondable stranded costs which are determined to be recoverable in a bondable stranded costs rate order, all rights of the related electric public utility under such bondable stranded costs rate order including, without limitation, all rights to obtain periodic adjustments of the related transition bond charges pursuant to subsection b. of section 15 of this act, and all revenues, collections, payments, money and proceeds arising under, or with respect to, all of the foregoing;

"Broker" means a duly licensed electric power supplier that assumes the contractual and legal responsibility for the sale of electric generation service, transmission or other services to end-use retail customers, but does not take title to any of the power sold, or a duly licensed gas supplier that assumes the contractual and legal obligation to provide gas supply service to end-use retail customers, but does not take title to the gas;

"Buydown" means an arrangement or arrangements involving the buyer and seller in a given power purchase contract and, in some cases third parties, for consideration to be given by the buyer in order to effectuate a reduction in the pricing, or the restructuring of other terms to reduce the overall cost of the power contract, for the remaining succeeding period of the purchased power arrangement or arrangements;

"Buyout" means an arrangement or arrangements involving the buyer and seller in a given power purchase contract and, in some cases third parties, for consideration to be given by the buyer in order to effectuate a termination of such power purchase contract;

"Class I renewable energy" means electric energy produced from solar technologies, photovoltaic technologies, wind energy, fuel cells, geothermal technologies, wave or tidal action, and methane gas from landfills or a biomass facility, provided that the biomass is cultivated and harvested in a sustainable manner;

"Class II renewable energy" means electric energy produced at a resource recovery facility or hydropower facility, provided that such facility is located where retail competition is permitted and provided further that the Commissioner of Environmental Protection has determined that such facility meets the highest environmental standards and minimizes any impacts to the environment and local communities;

"Competitive service" means any service offered by an electric public utility or a gas public utility that the board determines to be competitive pursuant to section 8 or section 10 of this act or that is not regulated by the board;

"Comprehensive resource analysis" means an analysis including, but not limited to, an assessment of existing market barriers to the implementation of energy efficiency and renewable technologies that are not or cannot be delivered to customers through a competitive marketplace;

"Customer" means any person that is an end user and is connected to any part of the transmission and distribution system within an electric public utility's service territory or a gas public utility's service territory within this State;

"Customer account service" means metering, billing, or such other administrative activity associated with maintaining a customer account;

"Demand side management" means the management of customer demand for energy service through the implementation of cost-effective energy efficiency technologies, including, but not limited to, installed conservation, load management and energy efficiency measures on and in the residential, commercial, industrial, institutional and governmental premises and facilities in this State;

"Electric generation service" means the provision of retail electric energy and capacity which is generated off-site from the location at which the consumption of such electric energy and capacity is metered for retail billing purposes, including agreements and arrangements related thereto;

"Electric power generator" means an entity that proposes to construct, own, lease or operate, or currently owns, leases or operates, an electric power production facility that will sell or does sell at least 90 percent of its output, either directly or through a marketer, to a customer or customers located at sites that are not on or contiguous to the site on which the facility will be located or is located. The designation of an entity as an electric power generator for the purposes of this act shall not, in and of itself, affect the entity's status as an exempt wholesale generator under the Public Utility Holding Company Act of 1935, 15 U.S.C. s.79 et seq.;

"Electric power supplier" means a person or entity that is duly licensed pursuant to the provisions of this act to offer and to assume the contractual and legal responsibility to provide electric generation service to retail customers, and includes load serving entities, marketers and brokers that offer or provide electric generation service to retail customers. The term excludes an electric public utility that provides electric generation service only as a basic generation service pursuant to section 9 of this act;

"Electric public utility" means a public utility, as that term is defined in R.S.48:2-13, that transmits and distributes electricity to end users within this State;

"Electric related service" means a service that is directly related to the consumption of electricity by an end user, including, but not limited to, the installation of demand side management measures at the end user's premises, the maintenance, repair or replacement of appliances, lighting, motors or other energy-consuming devices at the end user's premises, and the provision of energy consumption measurement and billing services;

"Electronic signature" means an electronic sound, symbol or process, attached to, or logically associated with, a contract or other record, and executed or adopted by a person with the intent to sign the record;

"Energy agent" means a person that is duly registered pursuant to the provisions of this act, that arranges the sale of retail electricity or electric related services or retail gas supply or gas related services between government aggregators or private aggregators and electric power suppliers or gas suppliers, but does not take title to the electric or gas sold;

"Energy consumer" means a business or residential consumer of electric generation service or gas supply service located within the territorial jurisdiction of a government aggregator;

"Financing entity" means an electric public utility, a special purpose entity, or any other assignee of bondable transition property, which issues transition bonds. Except as specifically provided in this act, a financing entity which is not itself an electric public utility shall not be subject to the public utility requirements of Title 48 or any rules or regulations adopted pursuant thereto;

"Gas public utility" means a public utility, as that term is defined in R.S.48:2-13, that distributes gas to end users within this State;

"Gas related service" means a service that is directly related to the consumption of gas by an end user, including, but not limited to, the installation of demand side management measures at the end user's premises, the maintenance, repair or replacement of appliances or other energy-consuming devices at the end user's premises, and the provision of energy consumption measurement and billing services;

"Gas supplier" means a person that is duly licensed pursuant to the provisions of this act to offer and assume the contractual and legal obligation to provide gas supply service to retail customers, and includes, but is not limited to, marketers and brokers. A non-public utility affiliate of a public utility holding company may be a gas supplier, but a gas public utility or any subsidiary of a gas utility is not a gas supplier. In the event that a gas public utility is not part of a holding company legal structure, a related competitive business segment of that gas public utility may be a gas supplier, provided that related competitive business segment is structurally separated from the gas public utility, and provided that the interactions between the gas public utility and the related competitive business segment are subject to the affiliate relations standards adopted by the board pursuant to subsection k. of section 10 of this act;

"Gas supply service" means the provision to customers of the retail commodity of gas, but does not include any regulated distribution service;

"Government aggregator" means any government entity subject to the requirements of the "Local Public Contracts Law," P.L.1971, c. 198 (C.40A:11-1 et seq.), the "Public School Contracts Law," N.J. Rev. Stat.18A:18A-1 et seq., or the "County College Contracts Law," P.L.1982, c. 189 (C.18A:64A-25.1 et seq.), that enters into a written contract with a licensed electric power supplier or a licensed gas supplier for: (1) the provision of electric generation service, electric related service, gas supply service, or gas related service for its own use or the use of other government aggregators; or (2) if a municipal or county government, the provision of electric generation service or gas supply service on behalf of business or residential customers within its territorial jurisdiction;

"Government energy aggregation program" means a program and procedure pursuant to which a government aggregator enters into a written contract for the provision of electric generation service or gas supply service on behalf of business or residential customers within its territorial jurisdiction;

"Governmental entity" means any federal, state, municipal, local or other governmental department, commission, board, agency, court, authority or instrumentality having competent jurisdiction;

"Market transition charge" means a charge imposed pursuant to section 13 of this act by an electric public utility, at a level determined by the board, on the electric public utility customers for a limited duration transition period to recover stranded costs created as a result of the introduction of electric power supply competition pursuant to the provisions of this act;

"Marketer" means a duly licensed electric power supplier that takes title to electric energy and capacity, transmission and other services from electric power generators and other wholesale suppliers and then assumes contractual and legal obligation to provide electric generation service, and may include transmission and other services, to an end-use retail customer or customers, or a duly licensed gas supplier that takes title to gas and then assumes the contractual and legal obligation to provide gas supply service to an end-use customer or customers;

"Net proceeds" means proceeds less transaction and other related costs as determined by the board;

"Net revenues" means revenues less related expenses, including applicable taxes, as determined by the board;

"On-site generation facility" means a generation facility, and equipment and services appurtenant to electric sales by such facility to the end use customer located on the property or on property contiguous to the property on which the end user is located. An on-site generation facility shall not be considered a public utility. The property of the end use customer and the property on which the on-site generation facility is located shall be considered contiguous if they are geographically located next to each other, but may be otherwise separated by an easement, public thoroughfare, transportation or utility-owned right-of-way;

"Person" means an individual, partnership, corporation, association, trust, limited liability company, governmental entity or other legal entity;

"Private aggregator" means a non-government aggregator that is a duly-organized business or non-profit organization authorized to do business in this State that enters into a contract with a duly licensed electric power supplier for the purchase of electric energy and capacity, or with a duly licensed gas supplier for the purchase of gas supply service, on behalf of multiple end-use customers by combining the loads of those customers;

"Public utility holding company" means: (1) any company that, directly or indirectly, owns, controls, or holds with power to vote, ten percent or more of the outstanding voting securities of an electric public utility or a gas public utility or of a company which is a public utility holding company by virtue of this definition, unless the Securities and Exchange Commission, or its successor, by order declares such company not to be a public utility holding company under the Public Utility Holding Company Act of 1935, 15 U.S.C. s.79 et seq., or its successor; or (2) any person that the Securities and Exchange Commission, or its successor, determines, after notice and opportunity for hearing, directly or indirectly, to exercise, either alone or pursuant to an arrangement or understanding with one or more other persons, such a controlling influence over the management or policies of an electric public utility or a gas public utility or public utility holding company as to make it necessary or appropriate in the public interest or for the protection of investors or consumers that such person be subject to the obligations, duties, and liabilities imposed in the Public Utility Holding Company Act of 1935 or its successor;

"Regulatory asset" means an asset recorded on the books of an electric public utility or gas public utility pursuant to the Statement of Financial Accounting Standards, No. 71, entitled "Accounting for the Effects of Certain Types of Regulation," or any successor standard and as deemed recoverable by the board;

"Related competitive business segment of an electric public utility or gas public utility" means any business venture of an electric public utility or gas public utility including, but not limited to, functionally separate business units, joint ventures, and partnerships, that offers to provide or provides competitive services;

"Related competitive business segment of a public utility holding company" means any business venture of a public utility holding company, including, but not limited to, functionally separate business units, joint ventures, and partnerships and subsidiaries, that offers to provide or provides competitive services, but does not include any related competitive business segments of an electric public utility or gas public utility;

"Resource recovery facility" means a solid waste facility constructed and operated for the incineration of solid waste for energy production and the recovery of metals and other materials for reuse;

"Restructuring related costs" means reasonably incurred costs directly related to the restructuring of the electric power industry, including the closure, sale, functional separation and divestiture of generation and other competitive utility assets by a public utility, or the provision of competitive services as such costs are determined by the board, and which are not stranded costs as defined in this act but may include, but not be limited to, investments in management information systems, and which shall include expenses related to employees affected by restructuring which result in efficiencies and which result in benefits to ratepayers, such as training or retraining at the level equivalent to one year's training at a vocational or technical school or county community college, the provision of severance pay of two weeks of base pay for each year of full-time employment, and a maximum of 24 months' continued health care coverage. Except as to expenses related to employees affected by restructuring, "restructuring related costs" shall not include going forward costs;

"Retail choice" means the ability of retail customers to shop for electric generation or gas supply service from electric power or gas suppliers, or opt to receive basic generation service or basic gas service, and the ability of an electric power or gas supplier to offer electric generation service or gas supply service to retail customers, consistent with the provisions of this act;

"Shopping credit" means an amount deducted from the bill of an electric public utility customer to reflect the fact that such customer has switched to an electric power supplier and no longer takes basic generation service from the electric public utility;

"Social program" means a program implemented with board approval to provide assistance to a group of disadvantaged customers, to provide protection to consumers, or to accomplish a particular societal goal, and includes, but is not limited to, the winter moratorium program, utility practices concerning "bad debt" customers, low income assistance, deferred payment plans, weatherization programs, and late payment and deposit policies, but does not include any demand side management program or any environmental requirements or controls;

"Societal benefits charge" means a charge imposed by an electric public utility, at a level determined by the board, pursuant to, and in accordance with, section 12 of this act;

"Stranded cost" means the amount by which the net cost of an electric public utility's electric generating assets or electric power purchase commitments, as determined by the board consistent with the provisions of this act, exceeds the market value of those assets or contractual commitments in a competitive supply marketplace and the costs of buydowns or buyouts of power purchase contracts;

"Stranded costs recovery order" means each order issued by the board in accordance with subsection c. of section 13 of this act which sets forth the amount of stranded costs, if any, the board has determined an electric public utility is eligible to recover and collect in accordance with the standards set forth in section 13 and the recovery mechanisms therefor;

"Transition bond charge" means a charge, expressed as an amount per kilowatt hour, that is authorized by and imposed on electric public utility ratepayers pursuant to a bondable stranded costs rate order, as modified at any time pursuant to the provisions of this act;

"Transition bonds" means bonds, notes, certificates of participation or beneficial interest or other evidences of indebtedness or ownership issued pursuant to an indenture, contract or other agreement of an electric public utility or a financing entity, the proceeds of which are used, directly or indirectly, to recover, finance or refinance bondable stranded costs and which are, directly or indirectly, secured by or payable from bondable transition property.

References in this act to principal, interest, and acquisition or redemption premium with respect to transition bonds which are issued in the form of certificates of participation or beneficial interest or other evidences of ownership shall refer to the comparable payments on such securities;

"Transmission and distribution system" means, with respect to an electric public utility, any facility or equipment that is used for the transmission, distribution or delivery of electricity to the customers of the electric public utility including, but not limited to, the land, structures, meters, lines, switches and all other appurtenances thereof and thereto, owned or controlled by the electric public utility within this State;

"Transition period" means the period from August 1, 1999 through July 31, 2003; and

"Universal service" means any service approved by the board with the purpose of assisting low-income residential customers in obtaining or retaining electric generation or delivery service.

N.J. Rev. Stat. § 48:3-52. Unbundling of electric public utility services and charges; credits; rate unbundling filings; manner and percentage of rate reduction

a. Simultaneously with the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, each electric public utility shall unbundle its rate schedules such that discrete services and charges provided, which were previously included in the bundled utility rate, are separately identified and charged in its tariffs. Such discrete services and charges shall include, at a minimum, customer account services and charges, distribution and transmission services and charges and generation services and charges, and the board may require that additional services and charges be unbundled and separately billed. Billings for such services also shall include charges related to regulatory assets and may include restructuring related costs. In the case of commercial and industrial customers, rate schedules shall remain unbundled, and in all billings for such customers after the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, the amount of the market transition charge authorized pursuant to section 13 of this act shall be added to the discrete services and charges identified. Residential rate schedules once unbundled, may be totally or partially rebundled for residential billing purposes. All competitive services offered by an electric public utility shall be charged separately from non-competitive services.

b. As part of its unbundled rate structure established in compliance with subsection a. of this section, an electric public utility providing basic generation service in accordance with section 9 of this act shall establish a separate charge for such service, as reviewed and approved by the board consistent with this act for billing purposes. An electric public utility which offers basic generation service in accordance with section 9 of this act shall also provide, simultaneously with the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, shopping credits applicable to the bills of their retail customers who choose to purchase electric generation service from a duly licensed electric power supplier. The board shall determine the appropriate level of shopping credits for each electric public utility in a manner consistent with the findings and declarations of the Legislature as set forth in section 2 of this act, and other provisions of this act. The reduction in electric public utility rates, as determined by the board in subsections d. and e. of this section, shall be consistent with the goals of this act, including the creation of shopping credits, as appropriate, pursuant to this subsection.

Each customer bill issued after the implementation of the rate reductions required or determined by the board pursuant to this section, including but not limited to any enhanced reductions resulting from a phase-in allowed pursuant to paragraph (2) of subsection d. of this section, shall indicate the dollar amount of the difference between what the customer's total charges would have been without the reduction and the total charges in that bill.

c. The board shall require electric public utilities to submit rate unbundling filings in a form adopted by the board. The board shall review such filings and, after hearing and an opportunity for public comment, render a determination as to the appropriate, unbundled rates consistent with the provisions of this act. Notwithstanding any other provisions of this act, an unbundling of electric public utility rates implemented as a result of this section shall nct result in a reallocation of utility cost responsibility between or among different classes of customers.

d. (1) During a term to be fixed by the board, each electric public utility shall reduce its aggregate level of rates for each customer class, including any surcharges assessed pursuant to this act, by a percentage to be approved by the board, which shall be at least 10 percent relative to the aggregate level of bundled rates in effect as of April 30, 1997, subject to the provisions of paragraph (2) of this subsection.

(2) The board may set a term for an electric public utility to phase in a rate reduction of ten percent or more during the first 36 months after the starting date for the implementation of retail choice as provided in subsection a. of section 5 of this act; provided, however, that, on the starting date for the implementation of retail choice as provided in subsection a. of section 5 of this act, each electric public utility shall reduce its aggregate level of rates for each customer class, including any surcharges assessed pursuant to this act, by no less than five percent.

e. The board may order a rate reduction that exceeds the 10 percent rate reduction as provided in subsection d. of this section, if it determines that such reductions are necessary in order to achieve just and reasonable rates.

f. The board shall determine, consistent with the provisions of this act, the manner in which to apply the rate reductions established pursuant to subsections d. and e. of this section among some or all of the unbundled rate components, including the distribution and transmission charges and market transition charges, in order to provide for a sustainable aggregate rate reduction for customers and to encourage a competitive retail supply marketplace.

g. Any subsequent order to reduce rates beyond those authorized by subsections d. and e. of this section may only be issued after notice and hearing.

h. Any tax reduction implemented pursuant to P.L.1997, c. 162 (C.54:30A-100 et al.) shall not be credited towards the rate reductions required pursuant to subsection d. and authorized pursuant to subsections d. and e. of this section.

i. The rate reduction associated with the reduction in the utility's capital costs, including related taxes, that results from the issuance of transition bonds pursuant to section 14 of this act shall be made no later than the date on which the transition bond charge, approved pursuant to section 14 of this act, becomes effective.

j. The maximum level of rate reduction determined by the board pursuant to this section shall be sustained at least until the end of the 48th month following the starting date for the implementation of retail choice as provided in subsection a. of section 5 of this act.

N.J. Rev. Stat. § 48:3-53. Electric public utility retail choice implementation date; restructuring filing

a. By order the board shall provide that by no earlier than June 1, 1999, but in no event later than August 1, 1999, each electric public utility shall provide retail choice of electric power suppliers for its customers. Each electric public utility shall fully implement retail choice in 100 percent of its franchise area within this State on the starting date of retail competition.

b. Each electric public utility shall comply with the schedule for the implementation of retail choice established pursuant to subsection a. of this section. The board shall have the authority to require each electric public utility to submit a restructuring filing, with elements deemed necessary by the board, which shall include the mechanisms by which it will comply with the schedule for implementation of retail choice established pursuant to subsection a. of this section and with the other provisions of this act. Such filing shall be reviewed and, after notice and hearing, may be approved, rejected or modified by the board, and the board may take such additional actions as it deems necessary to enforce compliance with this act.

N.J. Rev. Stat. § 48:3-54. Continued electric and gas services; regulations

a. An electric public utility may continue to offer customer account services on a regulated basis subsequent to the effective date of this act. Not later than three months after the starting date for the implementation of retail choice for any public utility as determined by the board pursuant to subsection a. of section 5 of this act, the board shall initiate a formal proceeding to investigate the manner and mechanics by which customers are afforded the opportunity to contract with the incumbent utility or an electric power supplier for customer account services and to establish the necessary standards for safety, reliability and testing for meters and information exchange protocols applicable to both electric power suppliers and incumbent utilities that will permit customers to choose a supplier for some or all such customer account services. The board shall issue an order for providing customers the opportunity to choose a supplier for some or all customer account services not later than one year from the starting date of retail competition as provided for in subsection a. of section 5 of this act and setting forth the manner, mechanics and standards for competitive customer account services. The board shall require that electric public utilities, in the continued regulated provision of customer account services, not take actions that would unreasonably impede a transition to a competitive customer account service market. Notwithstanding any other provision of this act to the contrary, an electric power supplier may, upon written consent from a customer, bill the customer directly for generation services and other services it provides to the customer as of the starting date for implementation of retail choice. The board shall ensure that the standards and protocols for electronic data exchange needed to support this option are adopted and are implemented by electric public utilities in a timely manner.

b. A gas public utility may continue to offer customer account services on a regulated basis subsequent to the effective date of this act. Not later than three months after the starting date for the implementation of retail choice established pursuant to section 10 of this act, the board shall initiate a formal proceeding to investigate the manner and mechanics by which customers are afforded the opportunity to contract with by the incumbent utility or gas supplier and to establish the necessary standards for safety, reliability and testing for meters and information exchange protocols applicable to both gas suppliers and incumbent utilities that will permit customers to choose a supplier for some or all such customer account services. The board shall issue an order for providing customers the opportunity to choose a supplier for some or all customer account services not later than December 31, 2000 and setting forth the manner, mechanics and standards for competitive customer account services. The board shall require that gas public utilities, in the continued regulated provision of customer account services, not take actions which would unreasonably impede a transition to a competitive customer account service market. Notwithstanding any other provision of this act to the contrary, a gas supplier may, upon written consent from a customer, bill the customer directly for gas supply service and other services it provides to the customer on and after the first billing which comports with the provisions of section 10 of this act pertaining to the provision of basic gas supply service. The board shall ensure that the standards and protocols for electronic data exchange needed to support this option are adopted and are implemented by gas public utilities in a timely manner.

c. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, interim technical standards to ensure the safety, reliability and accuracy of metering equipment provided to electric or gas customers and to establish protocols for the exchange of information related to the provision of customer account services.

N.J. Rev. Stat. § 48:3-55. Board approval for competitive services; electric public utility assets; tariffs; provision of competitive services

a. An electric public utility or a related competitive business segment of an electric public utility shall not offer any competitive service to retail customers within this State without the prior express written approval of the board. The board shall require that an electric public utility file and maintain tariffs for competitive services, which tariffs shall be subject to review and approval by the board. The board shall approve a competitive service only upon a finding that:

(1) The provision of a competitive service by an electric public utility or its related competitive business segment shall not adversely impact the ability of the electric public utility to offer its non-competitive services to customers in a safe, adequate and proper manner, and in all instances where resources are jointly deployed by the utility to provide competitive and non-competitive services and resource constraints arise, the provision of non-competitive services shall receive a higher priority; and

(2) The price which an electric public utility charges for a competitive service shall not be less than the fully allocated

cost of providing such service, as determined by the board, which cost shall include an allocation of the cost of all equipment, vehicles, labor, related fringe benefits and overheads, and administration utilized, and all other assets utilized and costs incurred, directly or indirectly, in providing such competitive service.

b. The board shall apply 50 percent of the net revenues earned from the offering of competitive services by an electric public utility or its related competitive business segment, or from the offering of competitive services by an electric public utility holding company or its related competitive business segment when the provision of such services utilizes affiliated electric public utility assets, including, but not limited to, equipment and personnel, unless the board finds that the electric public utility will receive and reflect such receipt as an offset to its regulated rates the full market value for the use of such assets pursuant to a contract between the parties filed with the board by the electric public utility and subject to the provisions of this section and section 8 of this act:

(1) To offset any market transition charge or equivalent rate mechanism assessed to customers pursuant to section 13 of this act; or

(2) If the electric public utility is not assessing a market transition charge, to offset the rates charged to customers for distribution service, except that such offset shall cease to be required after the term of the transition bond charge has expired as provided in paragraph (1) of subsection d. of section 14 of this act.

c. For the purposes of subsection b. of this section the following shall not constitute the utilization of electric public utility assets:

(1) movement or delivery of power pursuant to a federally-regulated open access tariff over transmission facilities owned by the electric public utility;

(2) movement or delivery of power pursuant to board regulated tariffs over distribution facilities owned by the electric public utility; and

(3) shared corporate overhead or administrative services subject to the provisions of section 8 of this act.

d. Pursuant to rules and regulations to be adopted by the board, the transfer of electric public utility assets from an electric public utility to a related competitive business segment of that electric public utility or of a public utility holding company, other than in the ordinary course of business, shall require board approval, and shall be recorded at full value as determined by the board. Notwithstanding this subsection, no transfer of assets shall affect the whole value of the assessment of the transitional energy facility assessment set forth in P.L.1997, c. 162 (C.54:30A-100 et al.).

e. Tariffs for competitive services filed with the board shall be in the public records, except that if the board determines that the rates are proprietary, they shall be filed under seal and made available under the terms of an appropriate protective agreement, as provided by board order. A public utility shall have the burden of proof by affidavit and motions to demonstrate the need for proprietary treatment. The rates shall become public upon board approval.

f. Subject to the approval of the board pursuant to subsection a. of this section, an electric public utility or a related competitive business segment of that electric public utility may provide the following competitive services:

(1) Metering, billing and related administrative services that are deemed competitive by the board pursuant to section 8 of this act;

(2) Services related to safety and reliability of utility businesses;

(3) Competitive services that have been offered by any electric public utility or gas public utility prior to January 1, 1993 or that have been approved by the board prior to the effective date of this act to be offered by any electric public utility or gas public utility. An electric public utility that has offered a competitive service since prior to January 1, 1993 or a competitive service that was approved by the board prior to the effective date of this act is not required to obtain board approval pursuant to subsection a. of this section for that service, but any electric public utility that has not offered a competitive service since prior to January 1, 1993 or has not received previous board approval for such a

competitive service shall apply for approval pursuant to subsection a. of this section. Except as otherwise provided by this paragraph, a competitive service that is permitted pursuant to this paragraph shall be subject to all requirements of this act for competitive services and to any standards or other rules or regulations adopted pursuant to this act;

(4) Services that the board determines to be substantially similar to competitive services that are permitted under paragraph (3) of this subsection; and

(5) Competitive services to non-residential customers using existing utility employees.

g. An electric public utility or a related competitive business segment of that electric public utility may provide other services that are offered for nominal or no consideration to existing non-residential customers in the ordinary course of business.

h. An electric public utility shall not use regulated rates to subsidize its competitive services or competitive services offered by a related competitive business segment of the public utility holding company of which the electric public utility is an affiliate, and expenses incurred in conjunction with its competitive services shall not be borne by its regulated rate customers. The regulated rates of an electric public utility shall be subject to the review and approval of the board to determine that there is no subsidization of its related competitive business segment. Each such public utility shall maintain books and records, and provide accounting entries of its regulated business to the board as may be required by the board, to show that there is strict separation and allocation of the utility's revenues, costs, assets, risks and functions, between the electric public utility and its related competitive business segment.

i. Any other provision of this act to the contrary notwithstanding, commencing on the effective date of this act, an electric public utility or a related competitive business segment of that electric public utility shall not offer any competitive service except those approved or pending approval as of July 1, 1998 pursuant to subsections a. and f. of this section.

j. A public utility holding company may offer any competitive service, including, but not limited to, electric generation service, telecommunications service, and cable television service, to retail customers of an electric public utility that is owned by the holding company, but only through a related competitive business segment of the holding company that is not an electric public utility or a related competitive business segment of the electric public utility. Competitive services shall be offered in compliance with all rules and regulations promulgated by the board for carriers of such services, including, but not limited to, telecommunications and cable.

k. Notwithstanding any other provisions of this section, by no later than December 31, 2000, the board shall render a decision, after notice and hearing, on any further restrictions required for any or all non-safety related competitive services offered by an electric public utility in addition to the provisions of this section, including whether an electric public utility offering non-safety related services shall establish and provide such services through a business unit which is functionally separated from the electric public utility business unit.

(1) Upon completion of the audit process required pursuant to paragraph (1) of subsection f. of section 8 of this act, the board shall commence a hearing process to examine the use of utility assets in providing retail competitive services as permitted in subsection f. of this section. The board shall evaluate and balance the following factors: the prevention of cross-subsidization; the issues attendant to separation and relative to the board's affiliate relation and fair competition standards as provided in section 8 of this act; the effect on ratepayers of the use of utility assets in the provision of non-safety related competitive services; the effect on utility workers; and the effect of utility practices on the market for such services.

(2) The relationship between the electric public utility and its related competitive service business unit shall be subject to affiliate relations standards to be promulgated by the board pursuant to subsection f. of section 8 of this act.

l. If a separate unit is established by the electric public utility as a related competitive business segment of the electric public utility such that other than shared administration and overheads, employees of the competitive services business unit shall not also be involved in the provision of non-competitive utility and safety services, and the competitive services are provided utilizing separate assets than those utilized to provide non-competitive utility and safety services, the board shall apply 25 percent of the net revenues:

(1) To offset any market transition charge or equivalent rate mechanism assessed to customers pursuant to section 13 of this act; or

(2) If the electric public utility is not assessing or has eliminated a market transition charge, to offset the rates charged to customers for distribution service, except that such offset shall cease to be required eight years after the start date of retail competition as provided in subsection a. of section 5 of this act.

N.J. Rev. Stat. § 48:3-56. Authority of the board

a. Except as otherwise provided in this act, and notwithstanding any provisions of R.S.48:218, R.S.48:2-21, section 31 of P.L.1962, c. 198 (C.48:2-21.2), R.S.48:3-1 or any other law to the contrary, the board shall not regulate, fix or prescribe the rates, tolls, charges, rate structures, rate base, or cost of service of competitive services.

b. For the purposes of this act, electric generation service is deemed to be a competitive service.

c. The board is authorized to determine, after notice and hearing, whether any other service offered by an electric public utility is a competitive service. In making such a determination, the board shall develop standards of competitive service which, at a minimum, shall include: evidence of ease of market entry; presence of other competitors; and the availability of like or substitute services in the relevant market segment and geographic area. Notwithstanding the presence of these factors, the board may determine that any service shall remain regulated for purposes of the public safety and welfare. d. The board is authorized to determine, after notice and hearing, and after appropriate review by the Legislature pursuant to subsection k. of this section,whether to reclassify as regulated any electric service or segment thereof that it has previously found to be competitive, including electric generation service, if it determines that sufficient competition is no longer present, upon application of the criteria set forth in subsection c. of this section. Upon such a reclassification, subsection a. of this section shall no longer apply and the board shall determine such rates for that electric service which it finds to be just and reasonable. The board, however, shall continue to monitor the electric service or segment thereof and, whenever the board shall find that the electric service has again become sufficiently competitive pursuant to subsection c. of this section, the board shall again apply the provisions of subsection a. of this section.

e. Nothing in this act shall limit the authority of the board, pursuant to Title 48 of the Revised Statutes, to ensure that electric public utilities do not make or impose unjust preferences, discriminations, or classifications for any services provided to customers.

f. (1) The board shall adopt, by rule, regulation or order, such fair competition standards, affiliate relation standards, accounting standards and reports as are necessary to ensure that electric public utilities or their related competitive business segments do not enjoy an unfair competitive advantage over other non-affiliated purveyors of competitive services and in order to monitor the allocation of costs between competitive and non-competitive services offered by an electric public utility, and within 60 days after the starting date for implementation of retail choice pursuant to subsection a. of section 5 of this act, shall commence the process of conducting audits, at the expense of the electric public utilities, to ensure compliance with this section and section 7 of this act and with the board's rules, regulations and orders adopted pursuant to this section and section 7 of this act. The board shall hire an independent contractor to perform such audits.

(2) Subsequent audits shall take place no less than every two years after the date of the decision rendered pursuant to subsection k. of section 7 of this act.

(3) The public utility or an intervenor shall have the right to contest the methodology and rebut the findings of an audit performed pursuant to this subsection, in a filing with the board. The board shall take no action to functionally separate, structurally separate or require the divestiture of any portion of a public utility's operations pursuant to this subsection until the public utility, and any intervenors, have been afforded timely opportunity to make such filing and until the board has issued a decision thereon.

(4) If the board finds, as a result of any such audit, that substantial violations of this act or of the board's rules, regulations or orders adopted pursuant to this section and section 7 of this act have occurred which result in unfair competitive advantages for an electric public utility, it shall: order the electric public utility to establish and provide such services through a business unit which is functionally separated from the electric public utility business unit as a related competitive business segment of the utility, such that, other than shared administration and overheads, employees of the competitive services business unit shall not also be involved in the provision of non-competitive utility and safety services, and the competitive services are provided utilizing separate assets than those utilized to provide noncompetitive utility and safety services; order the electric public utility to establish and provide such services through a structurally separate business unit or units including, but not limited to, a related competitive business segment of the public utility holding company; or order the electric public utility to divest itself of any business units that provide such services.

(5) If the board determines, as a result of the audit performed pursuant to this subsection that an electric public utility has unfairly allocated costs between its competitive and non-competitive services, the board is authorized to require such utility to return to the ratepayers an amount, equivalent to the amount of the costs determined to be unfairly allocated, with interest, during the time that the unfair allocation of costs occurred. In addition, the board is authorized to order such utility to pay a fine of up to $10,000 as a result of the violation or violations determined to have occurred pursuant to this subsection.

(6) Notwithstanding any requirements of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, such fair competition and accounting standards as are necessary on an interim basis to implement retail electric choice. Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

g. The board shall determine, by rule or order, what reports are necessary to monitor the competitiveness of any service offered to a customer of an electric public utility.

h. The board shall have the authority to take appropriate increasingly stringent action, including the issuance of an order that an electric public utility or its related competitive business segment cease the offering of a competitive service, functionally separate or structurally separate its competitive service offering from non-competitive business functions, or divest itself of such services, in the event that the board determines, after hearing, that recurring and significant violations of its rules or orders adopted pursuant to subsection f. of this section have occurred.

i. Nothing in this act shall exempt an electric public utility from obtaining all applicable local, State and federal licenses or permits associated with the offering of competitive services and complying with all applicable laws and regulations regarding the provision of such services.

j. If the board finds, as a result of any audit conducted pursuant to this section, that violations of the board's rules, regulations or orders adopted pursuant to this section and section 7 of this act have occurred, which are not substantial violations, the board is authorized to impose a fine of up to $10,000 against the electric public utility.

k. Prior to reclassifying as regulated any service it previously found to be competitive, the board shall make recommendations to the Legislature concerning the proposed reclassification. The recommendations shall be deemed to be approved unless the Legislature adopts a concurrent resolution stating that the Legislature is not in agreement with all or any part of the recommendations within 90 days following the date of transmittal of the recommendations to the Legislature. The concurrent resolution shall advise the board of the Legislature's specific objections to the recommendations and shall direct the board to submit revised recommendations which respond to those objections within 45 days of the date of transmittal of the concurrent resolution to the board.

N.J. Rev. Stat. § 48:3-57. Continued basic generation service by electric public utility; charges and power purchases

a. Simultaneously with the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, and for at least three years subsequent and thereafter until the board specifically finds it to be no longer necessary and in the public interest, each electric public utility shall provide basic generation service. Power procured for basic generation service by an electric public utility shall be purchased, at prices consistent with market conditions. The charges assessed to customers for basic generation service shall be regulated by the board and shall be based on the reasonable and prudent cost to the utility of providing such service, including the cost of power purchased at prices consistent with market conditions by the electric public utility in the competitive wholesale marketplace and related ancillary and administrative costs, as determined by the board. The board shall approve unbundled rates to assure that aggregate rate reductions established pursuant to section 4 of this act are sustained notwithstanding changes in basic generation charges approved pursuant to this section.

b. The board may allow an electric public utility to purchase power for basic generation service through a bilateral contract from a related competitive business segment of its public utility holding company only if:

(1) The related competitive business segment is not a related competitive business segment of the electric public utility; and

(2) The board determines that the procurement of power from the related competitive business segment of the public utility holding company is necessary in order to ensure the reliability of service to basic generation service customers or to address other extraordinary circumstances, and that the purchase price does not exceed the market price for such power or the power was procured through a competitive bid process subject to board review and approval. The board shall require that all net revenues derived from such sales, when the source of power is assets or contracts which costs are included in stranded costs recovery charges assessed pursuant to sections 13 and 14 of this act, shall be applied:

(a) To offset any market transition charge or equivalent rate mechanism assessed to customers pursuant to section 13 of this act; or

(b) If the electric public utility is not assessing a market transition charge, to offset the rates charged to customers for distribution service, except that such offset shall cease to be required after the term of the transition bond charge has expired as provided in paragraph (1) of subsection d. of section 14 of this act.

(3) The board may devise an alternative accounting or cost recovery process that permits an electric public utility to purchase power from a related competitive business segment of its public utility holding company, or otherwise, to provide basic generation service to its customers during the period that the electric public utility is providing for sustainable rate reductions pursuant to subsection j. of section 4 of this act and subsection a. of this section, if the board determines that such process is necessary to mitigate the impacts of market price fluctuations and to sustain such rate reductions.

c. No later than three years after the starting date of retail competition as provided in subsection a. of section 5 of this act, the board shall issue a decision as to whether to make available on a competitive basis the opportunity to provide basic generation service to any electric power supplier, any electric public utility, or both.

d. Power procured for basic generation service by an electric power supplier shall be purchased at prices consistent with market conditions. The charges assessed to customers for basic generation service shall be regulated by the board and shall be based on the reasonable and prudent cost to the supplier of providing such service, including the cost of power purchased at prices consistent with market conditions, by the supplier in the competitive wholesale marketplace and related ancillary and administrative costs, as determined by the board or shall be based upon the result of a competitive bid.

e. Each electric public utility or electric power supplier that provides basic generation service pursuant to subsection a., c. or d. of this section shall be permitted to recover in its basic generation charges on a full and timely basis all reasonable and prudently incurred costs incurred in the provision of basic generation services consistent with the provisions of this section, except to the extent that certain costs related to the provision of basic generation service are already being recovered in other elements of an electric public utility's charges. The board may approve ratemaking and other pricing mechanisms that provide incentives, including financial risks and rewards, for the utility or electric power supplier to procure a portfolio of electric power supply that provides maximum benefit to basic generation service customers.

f. Each electric public utility shall submit a quarterly report to the board of all electricity generation contracts between the public utility and any related competitive business segment. A utility that submits a report pursuant to this subsection may petition the board for confidential treatment as trade secrets of any or all of the information provided.

g. Nothing in this section shall apply to any existing board approved bilateral power purchase contract by an electric public utility as of the effective date of this act.

N.J. Rev. Stat. § 48:3-58. Unbundling of gas public utility services and charges; authority of the board; continued provision of basic gas supply

a. After the implementation of retail electric choice pursuant to subsection a. of section 5 of this act, the board shall order each gas public utility to unbundle its rate schedules such that discrete services provided, which were previously included in the bundled utility rate, are separately identified and charged in its tariffs. Billing for unbundled services also shall include charges for regulatory assets and may include restructuring related costs. The board shall order each gas public utility to submit a rate unbundling filing no later than May 1, 1999, in a form and of a content to be determined by the board. The board shall review such filings and, after hearing and an opportunity for public comment, render a determination as to the appropriate unbundled rates consistent with the provisions of this act. Notwithstanding any other provisions of this act, an unbundling of gas public utility rates implemented as a result of this section shall not result in a reallocation of utility cost responsibility between or among different classes of customers. The board shall continue to allow commercial and industrial customers to choose a gas supplier and shall order that all retail customers of a gas public utility shall be able to choose a gas supplier by no later than December 31, 1999, except that the board may approve an accelerated schedule for retail gas customer choice.

b. Subject to the approval of the board pursuant to subsection d. of this section, a gas public utility or a related competitive business segment of that gas public utility may provide the following competitive services:

(1) Metering, billing and related administrative services that are deemed competitive by the board pursuant to this section;

(2) Services related to safety and reliability of utility businesses;

(3) Competitive services that have been offered by any electric or gas public utility since prior to January 1, 1993 or that have been approved by the board prior to the effective date of this act to be offered by any electric public utility or gas public utility. A gas public utility that has offered a competitive service since prior to January 1, 1993 or a competitive service that was approved prior to the effective date of this act is not required to obtain board approval pursuant to subsection d. of this section, but any gas public utility that has not offered a competitive service prior to January 1, 1993 or has not received previous board approval for such a competitive service shall apply for approval pursuant to subsection d. of this section. Except as otherwise provided by this paragraph, a competitive service that is permitted by this paragraph shall be subject to all requirements of this act for competitive services and to any standards or other rules or regulations adopted pursuant to this act;

(4) Services that are substantially similar to competitive services that are permitted under paragraph (3) of this subsection; and

(5) Competitive services to non-residential customers using utility employees and assets.

c. A gas public utility or a related competitive business segment of that gas public utility may provide other services that are offered for nominal or no consideration to existing non-residential customers in the ordinary course of business.

d. A gas public utility shall not offer any competitive service to retail customers without the express prior written approval of the board. The board may require that a gas public utility file and maintain tariffs for competitive services, which tariffs shall be subject to review and approval by the board. The board shall approve a competitive service only upon a finding that:

(1) The provision of a competitive service by a gas public utility or its related competitive business segment shall not adversely impact the ability of the gas public utility to offer its non-competitive services to customers in a safe, adequate and proper manner, and in all instances where resources are jointly deployed by the utility to provide competitive and non-competitive services and resource constraints arise, the provision of non-competitive services shall receive a higher priority; and

(2) The price that a gas public utility charges for a competitive service shall not be less than the fully allocated cost of providing such service, as determined by the board, which cost shall include an allocation of the cost of all equipment, vehicles, labor, related fringe benefits and overheads, and administration utilized, and all other assets utilized and costs incurred, directly or indirectly, in providing such competitive service.

e. Tariffs for competitive services filed with the board shall be in the public records, except that if the board determines that the rates are proprietary, they shall be filed under seal and made available under the terms of an appropriate protective agreement, as provided by board order. A public utility shall have the burden of proof by affidavit and motions to demonstrate the need for proprietary treatment. The rates shall become public upon board approval.

f. A gas public utility shall not use regulated rates to subsidize its competitive services or competitive services offered by a related competitive business segment of the public utility holding company of which the public utility is an affiliate, and expenses incurred in conjunction with its competitive services shall not be borne by its regulated rate customers. The regulated rates of a gas public utility shall be subject to the review and approval of the board to determine that there is no subsidization of its related competitive business segment. Each such public utility shall maintain books and records, and provide accounting entries of its regulated business to the board as required by the board, to show that there is strict separation and allocation of the utility's revenues, costs, assets, risks and functions, between the gas public utility and its related competitive business segment.

g. Except as otherwise provided in this act, and notwithstanding any provisions of R.S.48:2-18, R.S.48:2-21, section 31 of P.L.1962, c. 198 (C.48:2-21.2), R.S.48:3-1 or any other law to the contrary, the board shall not regulate, fix or prescribe the rates, tolls, charges, rate structures, rate base, or cost of service of competitive services.

h. The board is authorized to determine, after notice and hearing, whether any service offered by a gas public utility is a competitive service. In making such a determination, the board shall develop standards of competitive service which, at a minimum, shall include: evidence of ease of market entry; presence of other competitors; and the availability of like or substitute services in the relevant geographic area. Notwithstanding the presence of these factors, the board may determine that any service shall remain regulated for purposes of the public safety and welfare.

i. The board shall have the authority to reclassify as regulated any gas service or segment thereof that it has previously found to be competitive, if, after notice and hearing, and after appropriate review by the Legislature pursuant to subsection v. of this section, it determines that sufficient competition is no longer present, upon application of the criteria set forth in subsection h. of this section. Upon such a reclassification, subsection g. of this section shall no longer apply and the board shall determine such rates for that gas service as it finds to be just and reasonable. The board, however, shall continue to monitor the gas service or segment thereof and, whenever the board shall find that the gas service has again become sufficiently competitive pursuant to subsection h. of this section, the board shall again apply the provisions of subsection g. of this section.

j. Nothing in this act shall limit the authority of the board, pursuant to Title 48 of the Revised Statutes, to ensure that gas public utilities do not make or impose unjust preferences, discriminations, or classifications for any services provided to customers.

k. (1) The board shall adopt, by rule, regulation or order, such fair competition standards, affiliate relation standards, accounting standards and reports as are necessary to ensure that gas public utilities or their related competitive business segments do not enjoy an unfair competitive advantage over other non-affiliated purveyors of competitive services and in order to monitor the allocation of costs between competitive and non-competitive services offered by a gas public utility, and within 60 days after the date for implementation of retail choice pursuant to this section, shall commence the process of conducting audits, at the expense of the gas public utilities, to ensure compliance with this section and with the board's rules, regulations or orders adopted pursuant to this section. The board shall hire an independent contractor to perform such audits.

(2) Subsequent audits shall take place no less than every two years after the date of the decision rendered pursuant to subsection q. of this section.

(3) The public utility and an intervenor shall have the right to contest the methodology and rebut the findings of an audit performed pursuant to this subsection, in a filing with the board. The board shall take no action to functionally separate, structurally separate or require the divestiture of any portion of a public utility's operations pursuant to this subsection until the public utility, and any intervenors have been afforded timely opportunity to make such filing and until the board has issued a decision thereon.

(4) If the board finds as a result of any such audit, that substantial violations of this act or of the board's rules, regulations or orders adopted pursuant to this section have occurred which result in unfair competitive advantages for a gas public utility, it shall: order the gas public utility to establish and provide such services through a business unit which is functionally separated from the gas public utility business unit as a related competitive business segment of the utility, such that, other than shared administration and overheads, employees of the competitive services business unit shall not also be involved in the provision of non-competitive utility and safety services, and the competitive services are provided utilizing separate assets than those utilized to provide non-competitive utility and safety services; order the gas public utility to establish and provide such services through a structurally separate business unit or units including, but not limited to, a related competitive business segment of the public utility holding company; or order the gas public utility to divest itself of any business units that provide such services.

(5) If the board determines, as a result of the audit performed pursuant to this subsection that a gas public utility has unfairly allocated costs between its competitive and non-competitive services, the board is authorized to require such utility to return to the ratepayers an amount, equivalent to the amount of the costs determined to be unfairly allocated, with interest, during the time that the unfair allocation of costs occurred. In addition, the board is authorized to order such utility to pay a fine of up to $10,000 as a result of the violation or violations determined to have occurred pursuant to this subsection.

l. The board shall determine, by rule or order, what reports are necessary to monitor the competitiveness of any service offered to a customer of a gas public utility.

m. The board shall have the authority to take appropriate action, including the issuance of an order that a gas public utility or its related competitive business segment cease the offering of a competitive service, functionally separate its competitive service offering from non-competitive business functions, structurally separate or divest itself of such services, in the event that the board determines, after hearing, that recurring and significant violations of its rules, regulations or orders adopted pursuant to subsection k. of this section have occurred.

n. Any other provision of this act to the contrary notwithstanding, commencing on the effective date of this act, a gas public utility or a related competitive business segment of that gas public utility shall not offer any competitive service except those approved or pending approval as of July 1, 1998 pursuant to subsections b. and d. of this section; provided, however, that in the event that a gas public utility is not part of a holding company legal structure, competitive services may be offered by a related competitive business segment of that gas public utility as long as that related competitive business segment is structurally separated from the gas public utility, and provided that the interactions between the gas public utility and the related competitive business segment are subject to the affiliate relation standards adopted by the board pursuant to subsection k. of this section.

o. A public utility holding company may offer a gas competitive service to retail customers of a gas public utility that is owned by the holding company, but only through a related competitive business segment of the holding company that is not a related competitive business segment of the gas public utility; provided, however, that in the event that a gas public utility is not part of a holding company legal structure, competitive services may be offered by a related competitive business segment of that gas public utility as long as that related competitive business segment is structurally separated from the gas public utility, and provided that interactions between the gas public utility and the related competitive business segment are subject to the affiliate relation standards adopted by the board pursuant to subsection k. of this section.

p. Nothing in this act shall exempt a gas public utility from obtaining all applicable local, State and federal licenses or permits associated with the offering of competitive services and complying with all applicable laws and regulations regarding the provision of such services.

q. Notwithstanding any other provisions of this section, by no later than December 31, 2000, the board shall render a decision, after notice and hearing, on any further restrictions required for any or all non-safety related competitive services offered by a gas public utility in addition to the provisions of this section, including whether a gas public utility offering non-safety related services must establish and provide such services through a business unit which is functionally separated from the gas public utility business unit.

(1) Upon the completion of the audit process required by paragraph (1) of subsection k. of this section, the board shall initiate the process of organizing and conducting hearings to examine the use of utility assets in providing retail competitive services as permitted in subsection f. of this section. The board shall evaluate and balance the following factors: the prevention of cross subsidization, the issues attendant to separation and relative to the board's affiliate relation and fair competition standards as provided in subsection k. of this section, the effect on ratepayers of the use of utility assets in the provision of non-safety related competitive services, the effect on utility workers, and the effect of utility practices on the market for such services.

(2) The relationship between the gas public utility and its related competitive service business unit shall be subject to affiliate relations standards to be promulgated by the board pursuant to subsection k. of this section.

r. For at least three years subsequent to the starting date of 100 percent retail competition as provided in subsection a. of this section and thereafter until the board specifically finds it to be no longer in the public interest, each gas public utility shall provide basic gas supply service. Gas supply procured for basic gas supply service by a gas public utility shall be purchased at prices consistent with market conditions. The charges assessed to customers for basic gas supply service shall be regulated by the board and shall be based on the cost to the utility of providing such service, including the cost of gas commodity and capacity purchased at prices consistent with market conditions by the gas public utility in the competitive wholesale marketplace and related ancillary and administrative costs, as determined by the board. A gas supply service offered by a gas public utility under a tariff approved by the board as of the effective date of this act shall qualify for the provision of basic gas supply service required hereunder.

s. By no later than January 1, 2002, the board shall issue a decision as to whether to make available basic gas service on a competitive basis to any gas supplier, any gas public utility, or both.

t. Gas procured for basic gas supply service by a gas supplier shall be purchased at prices consistent with market conditions. The charges assessed to customers for basic gas service shall be regulated by the board and shall be based on the cost to the supplier of providing such service, including the cost of gas commodity and capacity purchased at prices consistent with market conditions by the supplier in the competitive wholesale marketplace and related ancillary and administrative costs, as determined by the board or shall be based upon the result of a competitive bid.

u. Each gas public utility or gas supplier that provides basic gas supply service pursuant to subsections r., s. and t. of this section shall be permitted to recover in its basic gas supply charges on a full and timely basis all reasonable and prudently incurred costs incurred in the provision of basic gas supply services pursuant to this section, except to the extent that certain costs related to the provision of basic gas supply service are already being recovered in other elements of a gas public utility's charges. The board may approve ratemaking and other pricing mechanisms that provide incentives, including financial risks and rewards, for the gas public utility or gas supplier to procure a portfolio of gas supply that provides maximum benefit to basic gas supply service customers.

v. Prior to reclassifying as regulated, pursuant to subsection i. of this section, any service previously found to be competitive, the board shall make recommendations to the Legislature concerning the proposed reclassification. The recommendations shall be deemed to be approved unless the Legislature adopts a concurrent resolution stating that the Legislature is not in agreement with all or any part of the recommendations within 90 days following the date of transmittal of the recommendations to the Legislature. The concurrent resolution shall advise the board of the Legislature's specific objections to the recommendations and shall direct the board to submit revised recommendations which respond to those objections within 45 days of the date of transmittal of the concurrent resolution to the board.

w. If the board finds, as a result of any audit conducted pursuant to this section, that violations of the board's rules, regulations or orders adopted pursuant to this section have occurred, which are not substantial violations, the board is authorized to impose a fine of up to $10,000 against the gas public utility.

N.J. Rev. Stat. § 48:3-59. Electric public utilities; separation of functions; divestiture; sale of certain assets

a. On or after the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act and for the duration of the transition charges established pursuant to subsection i. of section 13 and subsection a. of section 14 of this act, the board may require that an electric public utility either:

(1) Functionally separate its non-competitive business functions from its competitive electric generation service or its electric power generator functions so that such services or functions are provided by a related competitive business segment of the public utility or the public utility holding company. A related competitive business segment of the public utility holding company that is providing competitive electric generation services or performing electric power generator functions shall not be considered a public utility for the purposes of regulation under Title 48 of the Revised Statutes or any other State law or rule or regulation, except that the interrelationships between the related competitive business segment and the electric public utility shall be subject to board authority and oversight consistent with the provisions of this section; or

(2) Divest to an unaffiliated company all or a portion of its electric generation assets and operations, upon a finding by the board, that such divestiture is necessary because the concentration or location of electric generation facilities under the electric public utility's ownership or control enable it to exercise market control that adversely affects the formation of a competitive electricity generation market and adversely affects retail electric supply customers by enabling the electric public utility or its related competitive business segment to gain an unfair competitive advantage or otherwise charge non-competitive prices.

b. Prior to the commencement by an electric public utility or a related competitive business segment of an electric public utility of any solicitation of bids for the sale of generating assets subject to recovery pursuant to sections 13 and 14 of this act or of the public utility holding company of any solicitation of bids for the sale of generating assets which have not been previously approved by the board for transfer from the electric public utility to the electric public utility holding company and are subject to recovery pursuant to sections 13 and 14 of this act, whether ordered by the board or not, the board shall establish standards for the conduct of such sale by the utility. Such standards shall include provisions for the board to monitor the progress of the bid process to ensure that the process is conducted by parties acting in their own best interest and in a manner designed to ensure a fair market value determination and does not unreasonably preclude participation by prospective purchasers. An order by the board, pursuant to paragraphs (1) and (2) of subsection a. of this section, ordering a public utility to functionally separate or divest its competitive services to a related competitive business segment of the public utility, a public utility, a public utility holding company or an unaffiliated company shall include a provision that the related competitive business segment of the public utility, public utility holding company or unaffiliated company shall:

(1) Recognize the existing employee bargaining unit and shall continue to honor and abide by an existing collective bargaining agreement for the duration of the agreement. The new entity shall be required to bargain in good faith with the existing collective bargaining unit when the existing collective bargaining agreement has expired;

(2) Shall hire its initial employee complement from among qualified employees of the electric public utility employed at the generating facility at the time of the functional separation or divestiture; and

(3) Continue such terms and conditions of employment of employees as are in existence at the generating facility at the time of the functional separation or divestiture.

c. Prior to completing any sale of generating assets subject to recovery pursuant to sections 13 and 14 of this act, an electric public utility shall file for and obtain approval by the board of the sale. The board shall approve the filing, subject to the provisions of subsection d. of this section, if it finds that:

(1) The sale reflects the full market value of the assets;

(2) The sale is otherwise in the best interest of the electric public utility's ratepayers;

(3) The sale will not jeopardize the reliability of the electric power system;

(4) The sale will not result in undue market control by the prospective buyer;

(5) The impacts of the sale on the utility's workers have been reasonably mitigated;

(6) The sale process is consistent with standards established by the board pursuant to subsection b. of this section;

(7) The sale, merger, or acquisition of the generation or other utility assets includes a provision that the purchasing, merging or new entity shall recognize the existing employee bargaining unit and shall continue to honor and abide by any existing collective bargaining agreement for the duration of the agreement. The new entity shall be required to bargain in good faith with the existing collective bargaining unit when the existing collective bargaining agreement has expired;

(8) The sale, merger, or acquisition of the generation or other utility assets includes a provision that the purchasing, merging or new entity shall hire its initial employee complement from among the employees of the electric public utility employed at the generating facility at the time of the sale, merger or acquisition; and

(9) The sale, merger or acquisition of the generation or other utility assets includes a provision that the purchasing, merging or new entity shall continue such terms and conditions of employment of employees as are in existence at the generating facility at the time of the sale, merger or acquisition.

d. Whenever an electric public utility sells generating assets subject to recovery pursuant to sections 13 and 14 of this act and the net proceeds from such sale exceed the level of market value used in determining the level of stranded costs being recovered through a market transition charge or equivalent rate mechanism established pursuant to section 13 of this act, the board shall require that all such excess revenues derived by the electric public utility or its related competitive business segment from that sale be applied:

(1) To offset any market transition charge or equivalent rate mechanism assessed to customers pursuant to section 13 of this act; or

(2) If the electric public utility is not assessing a market transition charge, to offset the rates charged to customers for distribution service.

e. Notwithstanding this subsection no transfer of assets shall affect the whole value of the assessment of the transitional energy facility assessment set forth in P.L.1997, c. 162 (C.54:30A-100 et seq.).

N.J. Rev. Stat. § 48:3-60. Recovery of costs; societal benefits charge

a. Simultaneously with the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, the board shall permit each electric public utility and gas public utility to recover some or all of the following costs through a societal benefits charge that shall be collected as a non-bypassable charge imposed on all electric public utility customers and gas public utility customers, as appropriate:

(1) The costs for the social programs for which rate recovery was approved by the board prior to April 30, 1997. For the purpose of establishing initial unbundled rates pursuant to section 4 of this act, the societal benefits charge shall be set to recover the same level of social program costs as is being collected in the bundled rates of the electric public

utility on the effective date of this act. The board may subsequently order, pursuant to its rules and regulations, an increase or decrease in the societal benefits charge to reflect changes in the costs to the utility of administering existing social programs. Nothing in this act shall be construed to abolish or change any social program required by statute or board order or rule or regulation to be provided by an electric public utility. Any such social program shall continue to be provided by the utility until otherwise provided by law, unless the board determines that it is no longer appropriate for the electric public utility to provide the program, or the board chooses to modify the program;

(2) Nuclear plant decommissioning costs;

(3) The costs of demand side management programs that were approved by the board pursuant to its demand side management regulations prior to April 30, 1997. For the purpose of establishing initial unbundled rates pursuant to section 4 of this act, the societal benefits charge shall be set to recover the same level of demand side management program costs as is being collected in the bundled rates of the electric public utility on the effective date of this act. Within four months of the effective date of this act, and every four years thereafter, the board shall initiate a proceeding and cause to be undertaken a comprehensive resource analysis of energy programs, and within eight months of initiating such proceeding and after notice, provision of the opportunity for public comment, and public hearing, the board, in consultation with the Department of Environmental Protection, shall determine the appropriate level of funding for energy efficiency and Class I renewable energy programs that provide environmental benefits above and beyond those provided by standard offer or similar programs in effect as of the effective date of this act; provided that the funding for such programs be no less than 50% of the total statewide amount being collected in public electric and gas utility rates for demand side management programs on the effective date of this act for an initial period of four years from the issuance of the first comprehensive resource analysis following the effective date of this act, and provided that 25% of this amount shall be used to provide funding for Class I renewable energy projects in the State. In each of the following fifth through eighth years, the Statewide funding for such programs shall be no less than 50 percent of the total statewide amount being collected in public electric and gas utility rates for demand side management programs on the effective date of this act, except that as additional funds are made available as a result of the expiration of past standard offer or similar commitments, the minimum amount of funding for such programs shall increase by an additional amount equal to 50 percent of the additional funds made available, until the minimum amount of funding dedicated to such programs reaches $140,000,000 total. After the eighth year the board shall make a determination as to the appropriate level of funding for these programs. Such programs shall include a program to provide financial incentives for the installation of Class I renewable energy projects in the State, and the board, in consultation with the Department of Environmental Protection, shall determine the level and total amount of such incentives as well as the renewable technologies eligible for such incentives which shall include, at a minimum, photovoltaic, wind, and fuel cells. The board shall simultaneously determine, as a result of the comprehensive resource analysis, the programs to be funded by the societal benefits charge, the level of cost recovery and performance incentives for old and new programs and whether the recovery of demand side management programs' costs currently approved by the board may be reduced or extended over a longer period of time. The board shall make these determinations taking into consideration existing market barriers and environmental benefits, with the objective of transforming markets, capturing lost opportunities, making energy services more affordable for low income customers and eliminating subsidies for programs that can be delivered in the marketplace without electric public utility and gas public utility customer funding;

(4) Manufactured gas plant remediation costs, which shall be determined initially in a manner consistent with mechanisms in the remediation adjustment clauses for the electric public utility and gas public utility adopted by the board; and

(5) The cost, of consumer education, as determined by the board, which shall be in an amount that, together with the consumer education surcharge imposed on electric power supplier license fees pursuant to subsection h. of section 29 of this act and the consumer education surcharge imposed on gas supplier license fees pursuant to subsection g. of section 30 of this act, shall be sufficient to fund the consumer education program established pursuant to section 36 of this act.

b. There is established in the Board of Public Utilities a nonlapsing fund to be known as the "Universal Service Fund." The board shall determine: the level of funding and the appropriate administration of the fund; the purposes and programs to be funded with monies from the fund; which social programs shall be provided by an electric public utility as part of the provision of its regulated services which provide a public benefit; whether the funds appropriated to fund the "Lifeline Credit Program" established pursuant to P.L.1979, c. 197 (C.48:2-29.15 et seq.), the "Tenants' Lifeline Assistance Program" established pursuant to P.L.1981, c. 210 (C.48:2-29.31 et seq.), the funds received pursuant to the Low Income Home Energy Assistance Program established pursuant to 42 U.S.C. s.8621 et seq., and funds collected by electric and natural gas utilities, as authorized by the board, to off-set uncollectible electricity and natural gas bills should be deposited in the fund; and whether new charges should be imposed to fund new or expanded social programs.

N.J. Rev. Stat. § 48:3-61. Categories of costs recoverable; market transition charge

a. The provisions of R.S.48:2-21 or any other law to the contrary notwithstanding, and simultaneously with the starting date for the implementation of retail choice as determined by the board pursuant to subsection a. of section 5 of this act, the board shall, pursuant to the findings made in connection with the stranded cost filing under subsection c. of this section and the related stranded costs recovery order, permit each electric public utility the opportunity to recover the following categories of costs through a market transition charge that shall be collected as a limited duration non-bypassable charge payable by all of the electric public utility's customers, except as provided pursuant to section 28 of this act:

(1) Utility generation plant stranded costs;

(2) Stranded costs related to long-term and short-term power purchase contracts with other utilities, including buydowns and buyouts of such contracts and interim debt, the issuance of which has been approved by the board, issued to effectuate the buydown or buyout of such contracts;

(3) Stranded costs related to long-term power purchase contracts with non-utility generators, including buydowns and buyouts of such contracts and interim debt issued to effectuate the buydown or buyout of such contracts, and the costs of new power contracts approved by the board which are the result of the renegotiation, restructuring or termination of previous non-utility generator power purchase contracts pursuant to subsection l. of this section; and

(4) Such restructuring related costs, if any, as the board determines to be appropriate for recovery in a market transition charge.

b. Costs that may be collected pursuant to subsection a. of this section must be otherwise unrecoverable as a direct result of the implementation of retail choice mandated by subsection a. of section 5 of this act.

c. In order for an electric public utility to have a market transition charge established it must submit a stranded cost filing to the board, the elements of which are to be established by the board. After notice and hearing, the board may approve, reject or approve with modifications the filing as it deems necessary and appropriate to comply with the provisions of this act and shall thereafter issue a stranded cost recovery order setting forth the amount of stranded costs, if any, eligible to be recovered by such electric public utility. The order or a successor order also shall set forth the board authorized mechanism to be used by the electric public utility for recovery of stranded costs which the board has determined are eligible for recovery.

d. Costs that may be eligible for recovery pursuant to paragraphs (1) and (2) of subsection a. of this section must have been committed to by the utility and included in rates through the conclusion of the utility's most recent base rate case prior to April 30, 1997, except that the board may determine certain costs that were not previously included in base rates to be eligible upon a showing by the utility that such costs were prudently incurred and either:

(1) were needed to maintain plant integrity, performance or reliability or to meet safety, environmental or other regulatory standards consistent with the utility's obligation to serve; or

(2) in the case of major investments or major upgrades not meeting the standard in subsection a. of this section, the utility demonstrates that it had no more cost-effective power supply source available at the time the commitment was made to meet their energy consumers' needs consistent with applicable board standards and to provide benefits to ratepayers.

e. For the purposes of quantifying the magnitude of stranded costs eligible for recovery via the market transition charge, the board shall require the electric public utility to demonstrate the full market value of each eligible generating asset or power purchase commitment over its remaining useful life or term and, in fixing the level of the market transition charge, the board shall reach a determination as to the market value of such eligible assets and commitments, or implement a mechanism for such value to be determined. Such determination or mechanism shall reflect or provide a means to reflect the full value of the eligible asset or commitment, including value which may not be realized by the electric public utility until after the expiration of the market transition charge, and may reflect a reduced return, if any, on investment in quantifying stranded costs which the board determines to be reasonable given the changes in capital costs or risks to the utility, or to reflect the impaired value of the uneconomic generating assets to ratepayers.

f. For the purposes of quantifying the magnitude of stranded costs eligible for recovery via the market transition charge, the board shall require or impute all reasonably available measures for the electric public utility to mitigate the quantity of stranded costs, by:

(1) Reducing the cost of power purchase commitments and the on-going capital and operations costs of the generating plant;

(2) Maximizing the market value of the generating asset or purchase commitment; or

(3) Undertaking other reasonably achievable cost reductions.

g. The board shall conduct a periodic review and, if necessary, adjust the market transition charge or implement other ratemaking mechanisms in order to ensure that the utility will not collect charges that exceed its actual stranded costs. Net proceeds from the sale or lease of generating assets as provided in subsection d. of section 11 of this act or from the offering of competitive services by the electric public utility or a related competitive business segment of the public utility as provided in subsection b. of section 7 of this act, shall be reflected on a timely basis in the first instance by the adjustment of the market transition charge or equivalent rate mechanism implemented pursuant to this subsection. Any adjustment mechanism shall reflect changes in market price and may reflect other factors such as changes in sales.

h. Notwithstanding the provisions of subsection a. of this section, the board shall not determine a level for the market transition charge for recovery of a utility's eligible stranded costs, as determined in accordance with this section, which prevents the achievement of the rate reductions required pursuant to section 4 of this act and that such rate reductions will not impair the electric public utility's financial integrity such that access to the capital markets for the continued provision of safe, adequate, and proper utility service is impaired.

i. The market transition charge for each utility shall be limited to a term not to exceed eight years, except that the board may extend the term of the charge to allow a utility:

(1) To recover the non-mitigable stranded costs associated with payments under long-term power purchase contracts with non-utility generators over the lives of the contracts;

(2) To recover costs associated with a particular generating asset, the costs of which represent at least 20 percent of an electric public utility's stranded costs as determined by the board and the remaining life of which for depreciation purposes at April 30, 1997 was 10 years or greater, in which case the board may extend the market transition charge up to three additional years if necessary to achieve the rate reduction levels established by the board pursuant to section 4 of this act; or

(3) To achieve the mandatory rate reductions established pursuant to subsection d. of section 4 of this act if the board determines that such mandatory rate reductions cannot be achieved by a public electric utility absent such extension.

j. The board shall issue orders with respect to each electric public utility's amortization of stranded costs through the market transition charge pursuant to this section prior to the starting date for implementation of retail choice as provided in subsection a. of section 5 of this act.

k. Nothing in this act shall be construed to alter non-utility generator power purchase contracts in existence on the effective date of this act or the board's orders approving said contracts.

l. (1) The board may approve the buyout or buydown of a power purchase agreement with a non-utility generator or a new power purchase contract which is the result of the renegotiation, restructuring or termination of a previous non-utility generator purchase agreement, if it determines that such buyout, buydown or new contract, including any and all transaction costs, will result in a substantial reduction in the total stranded costs of the utility, which resulting savings will be passed through to ratepayers on a full and timely basis.

(2) Each electric public utility shall be permitted to recover the costs of qualified replacement power on a full and timely basis pursuant to section 9 of this act.

(3) Each electric public utility shall be permitted to recover on a full and timely basis through the market transition charge:

(a) all costs of power contract buydowns and buyouts approved by the board which are the result of the renegotiation, restructuring, buyout, buydown or termination of existing non-utility power purchase contracts; and

(b) debt issued to effectuate the board-approved renegotiation, restructuring, buyout, buydown, or termination of existing non-utility power purchase contracts.

(4) The board's approval of any contract renegotiation, restructuring, buyout, buydown, termination or new contract shall not be subject to modification except as requested jointly by the parties to such contracts.

(5) As used in this subsection, "qualified replacement power" is power that the utility purchases subsequent to the board-approved buyout, buydown or renegotiation of a non-utility generator power purchase contract which is necessary to provide basic generation service and in order to replace power not provided as part of the buydown, buyout or new contract, and which is obtained at a cost no higher than that which is available in the market.

N.J. Rev. Stat. § 48:3-62. Stranded cost recovery; transition bonds

a. For purposes of recovering a portion of the stranded costs of an electric public utility that are deemed eligible for rate recovery in a stranded cost recovery order consistent with the provisions of section 13 of this act, and for compliance by the electric public utility with the rate reduction requirements determined by the board to be necessary and appropriate consistent with the provisions of sections 4 and 13 of this act, or for the purposes of recovering basic generation service transition costs of an electric public utility, the board may authorize the issuance of transition bonds by the electric public utility or other financing entity approved by the board. Such bonds shall be secured through an irrevocable bondable stranded cost rate order imposing a non-bypassable transition bond charge as provided in section 18 of this act and shall provide for collection of the transition bond charge by the electric public utility or another entity approved by the board. This transition bond charge shall be assessed in connection with the recovery of stranded costs pursuant to section 13 of this act or basic generation service transition costs pursuant to this section, but each electric public utility shall maintain separate accounting for transition bond charges so that the board can determine, at any time, the amount of each type of charge that has been assessed and collected by the electric public utility. The net proceeds of the transition bonds shall be used by or on behalf of the electric public utility solely for the purposes of reducing the amount of its otherwise recovery-eligible stranded costs, as determined by the board in accordance with the provisions of section 13 of this act, or reducing the amount of basic generation service transition costs through the refinancing or retirement of electric public utility debt or equity, or both, or the buyout, buydown or other restructuring of a power purchase agreement if such buyout, buydown or restructuring leads directly to substantial customer benefits over the term of the power purchase agreement. The entire amount of cost savings achieved as a result of the issuance of such transition bonds, whether as a result of a reduction in capital costs or a lengthened recovery period associated with otherwise recovery-eligible stranded costs or basic generation service transition costs or as a source of cash for the buyout, buydown or other restructuring of a power purchase agreement, shall be passed on to the customers of the electric public utility in the form of reduced rates or mitigated rate increases for electricity. Anything in this act or any other law to the contrary notwithstanding, except for adjustments authorized under paragraph (2) of subsection a. and subsection b. of section 15 of this act, transition bond charges approved by the board in a bondable stranded costs rate order shall not be offset, reduced, adjusted or otherwise diminished either directly or indirectly.

b. For the purposes of recovering stranded costs of an electric public utility, the issuance of transition bonds for an electric public utility may be authorized by the board if all the following findings are made by the board in connection with its review of a stranded cost filing made by an electric public utility pursuant to section 13 of this act:

(1) The electric public utility has taken reasonable measures to date, and has the appropriate incentives or plans in place to take reasonable measures, to mitigate the total amount of its stranded costs;

(2) The electric public utility will not be able to achieve the level of rate reduction deemed by the board to be necessary and appropriate pursuant to the provisions of sections 4 and 13 of this act absent the issuance of transition bonds;

(3) The issuance of such bonds will provide tangible and quantifiable benefits to ratepayers, including greater rate reductions than would have been achieved absent the issuance of such bonds and net present value savings over the term of the bonds; and

(4) The structuring and pricing of the transition bonds assure that the electric public utility's customers pay the lowest transition bond charges consistent with market conditions and the terms of the bondable stranded costs rate order. If so authorized in the financing order by the board, the structure and pricing of the transition bonds shall be conclusively deemed to satisfy this requirement if so certified by a designee of the board upon the pricing of the transition bonds, which certification will be final and uncontestable as of its date.

c. Subject to the other requirements of this section:

(1) The board may authorize the issuance of transition bonds for utility generation plant stranded costs determined by the board to be recoverable pursuant to paragraph (1) of subsection a. of section 13 of this act in a principal amount of up to 75 percent of the total amount of the electric public utility's recovery-eligible utility generation plant stranded costs, as determined by the board in accordance with the provisions of section 13 of this act, or, in the event that an electric public utility divests itself of a majority of its generating assets, which divestiture will result in a lower market transition charge than that which would have been collected from customers had the electric public utility not divested such assets, and the utility has established, as determined by the board, the stranded cost amount with certainty attributable to its remaining generating asset or assets, the board may authorize the issuance of transition bonds in a principal amount up to the full stranded cost value of such remaining generating asset or assets based on the following criteria:

(a) The greater the level of aggregate rate reduction provided pursuant to subsections d. and e. of section 4 of this act, the higher the percentage of stranded costs for which transition bonds may be issued;

(b) The higher the degree of certainty, such as might be obtained by auction or sale of the assets, as to the magnitude of the electric public utility's actual stranded costs, the larger the magnitude of transition bonds which may be permitted; and

(c) Based on evidence on the record, such amount will produce substantial and quantifiable savings for the customers of that utility;

(2) The board may authorize the issuance of transition bonds for the buyout or buydown of long-term power purchase contracts with non-utility generators determined by the board to be recoverable pursuant to paragraph (3) of subsection a. of section 13 of this act in a principal amount to be determined by the board in accordance with the provisions of section 13 of this act, based on the following criteria:

(a) The greater the level of aggregate rate reduction provided pursuant to subsections d. and e. of section 4 of this act, the higher the percentage of stranded costs that may be securitized;

(b) The higher the degree of certainty as to the magnitude of the electric public utility's actual stranded costs, the larger the magnitude of transition bonds which may be permitted; and

(c) Based on evidence on the record, such amount will produce substantial and quantifiable savings for the customers of that electric public utility because the amount of the buyout or buydown payment is substantially less than the total projected stranded costs associated with the contract; and

(3) The board may authorize the issuance of transition bonds for the recovery of up to the full amount of an electric public utility's reasonably and prudently incurred basic generation service transition costs based on the criteria that such amount will produce benefits for customers of the electric public utility which include the lowest transition bond charges consistent with market conditions and the terms of the bondable stranded costs rate order.

d. The board may approve transition bonds with scheduled amortization upon issuance of up to:

(1) Fifteen years if the electric public utility intends to utilize the proceeds from such transition bonds to reduce the stranded costs related to utility-owned generation;

(2) The remaining term of a power purchase agreement if the electric public utility intends to utilize the proceeds from such transition bonds solely for the purposes and requirements of paragraph (2) of subsection c. of this section; or

(3) Fifteen years if the electric public utility intends to utilize the proceeds from such transition bonds for the purpose of the recovery of basic generation service transition costs.

e. Transition bonds for the purpose and requirements of paragraph (1), (2) or (3) of subsection c. of this section may be issued in one or more series, in one or more offerings, and each such series may consist of one or more classes of transition bonds.

f. The board shall issue orders with respect to each electric public utility's amortization of stranded costs or basic generation service transition costs through the transition bond charges pursuant to this section.

g. For the purpose of recovering basic generation service transition costs, an electric public utility may make a filing in a form to be adopted by the board to request the board to authorize the issuance of transition bonds and to issue a bondable stranded cost rate order. The board shall review such filing, and after providing appropriate notice and an opportunity for hearing, may render a determination authorizing the issuance of transition bonds. If so authorized in the financing order by the board, the structure and pricing of the transition bonds shall be conclusively deemed to assure the lowest transition bond charges consistent with market conditions and the terms of the bondable stranded costs rate order when so certified by a designee of the board upon the pricing of the transition bonds, which certification will be final and uncontestable as of its date.

N.J. Rev. Stat. § 48:3-63. Proceeds; tax consequences

a. All proceeds received from the issuance of transition bonds shall not be considered income to the electric public utility or gas public utility for the purposes of the "Corporation Business Tax Act (1945)," P.L.1945, c. 162 (C.54:10A-1 et seq.) or the "New Jersey Gross Income Tax Act," P.L.1976, c. 47 (C.54A:1-1 et seq.).

b. The Director of the Division of Taxation in the Department of the Treasury is authorized to issue regulations regarding the determination of profit or loss related to the sale of assets which have been deemed to be part of stranded costs pursuant to sections 13 and 14 of this act for purposes of computing the corporation business tax to which the utility is subject.

N.J. Rev. Stat. § 48:3-64. Bondable stranded costs rate orders

a. A bondable stranded costs rate order issued by the board pursuant to section 14 of this act shall:

(1) Authorize the electric public utility or other financing entity approved by the board to issue transition bonds to finance the bondable stranded costs and to pledge or assign, sell or otherwise transfer the related bondable transition property without further order of the board, except as provided in paragraph (2) of subsection a. of this section;

(2) Approve the amount of the initial transition bond charge to be imposed upon, charged to and collected and received from the customers of the electric public utility in an amount not less than the amount necessary to fully recover bondable stranded costs, and provide for adjustment in a manner approved by the board of the initial transition bond charge prior to the closing of the related transition bonds to reflect the actual rate of interest thereon and all other costs, including any required overcollateralization, associated with the issuance of such transition bonds; and

(3) Require the electric public utility to obtain the approval of the board or its designee at the time of pricing of the terms and conditions of any transition bonds secured by or payable from the transition bond charges, servicing fees, if any, imposed with respect to the collection of such transition bond charges, or any pledging, assignment, sale or other transfer of bondable transition property in connection with the initial transition bond charge provided in paragraph (2) of subsection a. of this section, including a schedule of payments of principal and interest on the transition bonds, which notice shall be given not later than five business days after issuance and sale of the transition bonds. Notwithstanding any other provision of law, the notice to the board required to be given by the electric public utility in connection with the issuance and sale of transition bonds under this subsection shall not be subject to the provisions of R.S.48:3-7 and R.S.48:3-9 and shall not affect the rights of bondholders.

b. Each bondable stranded costs rate order shall provide for mandatory periodic adjustments by the board of the transition bond charges that are the subject of the bondable stranded costs rate order, upon petition of the affected electric public utility, its assignee or financing entity, to conform the transition bond charges to the schedule of payments of principal and interest on the transition bonds provided to the board by the electric public utility pursuant to subsection a. of this section. Such adjustments shall be made at least annually. Each such adjustment shall be formula-based, shall be in the amount required to ensure receipt of revenues sufficient to provide for the full recovery of bondable stranded costs, including, without limitation, the timely payment of principal of, and interest and acquisition or redemption premium on, transition bonds issued to finance such bondable stranded costs, which shall be recovered over the term of the transition bonds and in accordance with the schedule of payments of principal and interest on the transition bonds provided to the board by the electric public utility pursuant to subsection a. of this section and shall become effective 30 days after filing thereof with the board absent a determination of manifest error by the board. The electric public utility shall propose such adjustments in a filing with the board at least 30 days in advance of the date upon which it is requested to be effective. The proposed adjustment shall become effective on an interim basis on such date and, in the absence of a board order to the contrary, shall become final 60 days thereafter. Each such adjustment shall be formula-based and shall be in the amount required to ensure receipt of revenues sufficient to provide for the full recovery of bondable stranded costs including, without limitation, the timely payment of principal of, and interest and acquisition or redemption premium on, transition bonds issued to finance such bondable stranded costs, which shall be recovered over the term of the transition bonds and in accordance with the schedule of payments of principal and interest on the transition bonds provided to the board by the electric public utility pursuant to subsection a. of this section. Such periodic adjustments shall not in any way affect the validity or irrevocability of the bondable stranded costs rate order or any sale, assignment or other transfer of or any pledge or security interest granted with respect to the related bondable transition property and shall not affect rights of bondholders.

c. A bondable stranded costs rate order and the authority to meter, charge, collect and receive the transition bond charges authorized thereby shall remain in effect until the related bondable stranded costs, including, without limitation, the principal of, and accrued interest and acquisition or redemption premium on, any transition bonds issued to finance such bondable stranded costs, have been paid in full and all other obligations and undertakings with respect thereto have been fully satisfied. Until the bondable stranded costs, including, without limitation, the principal of, and accrued interest and acquisition or redemption premium on, any transition bonds issued to finance such bondable stranded costs, have been paid in full and all other obligations and undertakings with respect thereto have been fully satisfied, the electric public utility shall be obligated to provide electricity through its transmission and distribution system to its customers and shall have the right to meter, charge, collect and receive the transition bond charges arising therefrom from its customers, which rights and obligations may be assignable solely within the discretion of the electric public utility.

d. Each bondable stranded costs rate order shall provide that any transition bond charges held by the assignee or trustee of the related transition bonds in excess of those amounts necessary to fully recover bondable stranded costs approved in the bondable stranded costs rate order shall be applied as a credit to reduce charges to customers of the electric public utility, except that all bondable stranded costs as quantified in the bondable stranded costs rate orders with respect to the electric public utility shall be aggregated for purposes of determining whether or not the total transition bond charges collected exceed the total bondable stranded costs attributable to such electric public utility and provided, further, that unless the electric public utility can demonstrate to the satisfaction of the board that such credit will result in a recharacterization of the tax, accounting, and other intended characteristics of the transition bonds, including, but not limited to, the following characteristics:

(1) the recognition of transition bonds as debt on balance sheet of the electric public utility for financial accounting purposes;

(2) treatment of the transition bonds as debt of the electric public utility or its affiliates for federal income tax purposes;

(3) treatment of the transfer of bondable transition property by the electric public utility as a true sale for bankruptcy purposes; and

(4) an adverse impact of the transition bonds on the credit rating of the electric public utility.

e. An electric public utility may commingle the revenues received from amounts charged, collected and received under transition bond charges for bondable stranded costs approved in any one or more bondable stranded costs rate orders with other funds of the electric public utility, which shall in no way affect the validity or irrevocability of any bondable stranded costs rate order issued in connection therewith or any sale, assignment or other transfer of or any pledge or security interest granted with respect to the bondable transition property created thereby.

f. Except as provided otherwise in this act, all proceedings in connection with the determination of bondable stranded costs, transition bond charges and bondable stranded costs rate orders shall be exempt from the provisions of Title 48 of the Revised Statutes and any regulations promulgated thereunder.

N.J. Rev. Stat. § 48:3-65. Bondable stranded costs rate orders; irrevocability

a. Notwithstanding any other provision of law, each bondable stranded costs rate order and the transition bond charges authorized therein shall become irrevocable upon the issuance of such order and its becoming effective pursuant to section 19 of this act. The bondable stranded costs rate order, the transition bond charges and the bondable transition property shall constitute a vested, presently existing property right upon the transfer to an assignee and receipt of consideration for such bondable transition property. Following such transfer and receipt of consideration, such property right in bondable transition property shall be vested *ab initio* in such assignee.

b. Neither the board nor any other governmental entity shall have the authority, directly or indirectly, legally or equitably, to rescind, alter, repeal, modify or amend a bondable stranded costs rate order, to revalue, reevaluate or revise the amount of bondable stranded costs, to determine that the transition bond charges or the revenues required to recover bondable stranded costs are unjust or unreasonable, or in any way to reduce or impair the value of bondable transition property, nor shall the amount of revenues arising with respect thereto be subject to reduction, impairment, postponement or termination, provided, however, that nothing in this section shall preclude adjustments of the transition bond charges in accordance with the provisions of paragraph (2) of subsection a. and of subsection b. of section 15 of this act.

N.J. Rev. Stat. § 48:3-66. Transition bonds and bondable stranded costs rate orders; agreements with the State

of New Jersey

a. The State of New Jersey does hereby pledge and agree with the holders of any transition bonds issued under the authority of this act, with the pledgee, owner or assignee of bondable transition property, with any financing entity which has issued transition bonds with respect to which a bondable stranded costs rate order has been issued and with any person who may enter into agreements with an electric public utility or an assignee or pledgee thereof or a financing entity pursuant to this act, that the State will not limit, alter or impair any bondable transition property or other rights vested in an electric public utility or an assignee or pledgee thereof or a financing entity or vested in the holders of any transition bonds pursuant to a bondable stranded costs rate order until such transition bonds, together with the interest and acquisition or redemption premium, if any, thereon, are fully paid and discharged or until such agreements are fully performed on the part of the electric public utility, any assignee or pledgee thereof or the financing entity or in any way limit, alter, impair or reduce the value or amount of the bondable transition property approved by a bondable stranded costs rate order, provided, however, that nothing in this section shall preclude the adjustment of the transition bond charges in accordance with subsection b. of section 15 of this act. Any financing entity is authorized to include this covenant and undertaking of the State of New Jersey in any documentation with respect to the transition bonds issued thereby.

b. A bondable stranded costs rate order issued under this act does not constitute a debt or liability of the State or of any political subdivision thereof, nor does it constitute a pledge of the full faith and credit of the State or any of its political subdivisions. The issuance of transition bonds under this act shall not directly, indirectly, or contingently obligate the State or any political subdivision thereof to levy or pledge any form of taxation therefor or to make an appropriation for their payment, and any such transition bonds shall be payable solely from the bondable transition property and such other proceeds or property as may be pledged therefor.

N.J. Rev. Stat. § 48:3-67. Transition bond charges

The transition bond charges established by the board in bondable stranded costs rate orders shall be assessed against all customers of the electric public utility, except as provided in section 28 of this act. Transition bond charges shall be established by the board in accordance with sections 14 and 15 of this act and shall apply equally to each customer of the electric public utility based on the amount of electricity delivered to the customer through the transmission and distribution system of the electric public utility or any successor.

N.J. Rev. Stat. § 48:3-68. Effectiveness of bondable stranded costs rate orders

Each bondable stranded costs rate order shall be effective only in accordance with the terms thereof and upon the written consent of the petitioning electric public utility to all such terms.

N.J. Rev. Stat. § 48:3-69. Transition bonds; recourse to credit and assets of issuer

Transition bonds shall be recourse only to the credit and assets of the issuer of the transition bonds.

N.J. Rev. Stat. § 48:3-70. Records of transition bond charges required

An electric public utility shall maintain or cause to be maintained records of transition bond charges which have been assessed and collected by the electric public utility for each bondable stranded costs rate order applicable to the electric public utility. Such electric public utility records and any records of a financing entity shall be made available by the electric public utility for inspection and examination within a reasonable time upon demand therefor by the board or the related financing entity.

N.J. Rev. Stat. § 48:3-71. Transition bonds; assignability; nature of transition property

a. Electric public utilities or other financing entities may, but are not required to, issue transition bonds authorized by the board in any bondable stranded costs rate order.

b. An electric public utility or its assignee may sell, assign and otherwise transfer all or portions of its interest in bondable transition property to assignees or financing entities in connection with the issuance of transition bonds. In addition, an electric public utility, an assignee or a financing entity may pledge, grant a security interest in, or encumber bondable transition property as collateral for transition bonds.

c. Bondable transition property shall constitute an account and shall constitute presently existing property for all purposes, including for contracts securing transition bonds, whether or not the revenues and proceeds arising with respect thereto have accrued and notwithstanding the fact that the value of the property right may depend upon consumers using electricity or, in those instances where consumers are customers of a particular electric public utility, such electric public utility performing certain services. The validity of any sale, assignment or other transfer of bondable stranded cost shall not be defeated or adversely affected by the commingling by the electric public utility of revenues received from amounts charged, collected and received as transition bond charges with other funds of the electric public utility. Any description of the bondable transition property in a security agreement or financing statement filed with respect to the transfer of such bondable transition property in accordance with N.J. Rev. Stat.12A:9-501 et seq. shall be sufficient if it refers to the bondable stranded costs rate order establishing the bondable transition property.

d. A perfected security interest in bondable transition property is a continuously perfected security interest in all revenues and proceeds arising with respect thereto, whether or not the revenues and proceeds shall have accrued. The validity and relative priority of a pledge of, or security interest in, bondable transition property shall not be defeated or adversely affected by the commingling by the electric public utility of revenues received from amounts charged, collected and received as transition bond charges with other funds of the electric public utility. Any description of the bondable transition property in a security agreement or financing statement filed with respect to the granting of a security interest in such bondable transition property in accordance with N.J. Rev. Stat.12A:9-501 et seq. shall be sufficient if it refers to the bondable stranded costs rate order establishing the bondable transition property as provided by N.J. Rev. Stat.12A:9-108f.

e. In the event of default by the electric public utility or its assignee in payment of revenues arising with respect to the bondable transition property, and upon the application by the pledgees or transferees of the bondable transition property, the board or any court of competent jurisdiction shall order the sequestration and payment to the pledgees or transferees of revenues arising with respect to the bondable transition property, which application shall not limit any other remedies available to the pledgees or transferees by reason of the default. Any such order shall remain in full force and effect notwithstanding any bankruptcy, reorganization or other insolvency proceedings with respect to the debtor, pledgor or transferor of the bondable transition property. Any amounts in excess of amounts necessary to satisfy obligations then outstanding on or related to transition bonds shall be applied in the manner set forth in subsection d. of section 15 of this act.

f. To the extent that any such interest in bondable transition property is so sold or assigned, or is so pledged as collateral, the electric public utility shall be authorized to enter into a contract with the secured party, the assignee or the financing entity providing that the electric public utility shall continue to operate its transmission and distribution system to provide service to its customers, shall impose, charge, collect and receive transition bond charges in respect of the bondable transition property for the benefit and account of the secured party, the assignee or the financing entity, and shall account for and remit such amounts to and for the account of the secured party, the assignee or the financing entity. In the event of a default by the electric public utility in respect of charging, collecting and receiving revenues derived from transition bond charges and upon the application by the secured party, the assignee or the financing entity, the board or any court of competent jurisdiction shall by order designate a trustee or other entity to act in the place of the electric public utility to impose, meter, charge, collect and receive transition bond charges in respect of the bondable transition property for the benefit and account of the pledgee, the assignee or the financing entity. The board may, at its discretion, establish criteria for the selection of any entity that may become a servicer of bondable transition property upon the default or other adverse material change in the financial condition of the electric public utility.

g. An agreement by an assignor of bondable transition property not to assert any defense, claim or set-off against an assignee of the bondable transition property shall be enforceable against the assignor by the assignee and by any successor or subsequent assignee thereof.

N.J. Rev. Stat. § 48:3-72. Sale or other absolute transfer of bondable transition property

a. If an agreement by an electric public utility or its assignee to transfer bondable transition property expressly states that the transfer is a sale or other absolute transfer, then, notwithstanding any other provisions of law:

(1) Such transfer shall constitute a sale by the electric public utility or its assignee of all right, title, and interest of the electric public utility or its assignee, as applicable, in and to such bondable transition property;

(2) Such transfer shall constitute a sale or other absolute transfer of, and not a borrowing secured by, such bondable transition property;

(3) Upon execution and delivery of such agreement, the electric public utility or its assignee shall have no right, title or interest in or to such bondable transition property, except to the extent of any retained equity interest permitted by the provisions of this act; and

(4) The characterization of a transfer as a sale or other absolute transfer shall not be affected or impaired in any manner by, among other things: (a) the assignor's retention, or acquisition as part of the assignment transaction or otherwise, of a *pari passu* equity interest in bondable transition property or the fact that only a portion of the bondable transition property is otherwise transferred; (b) the assignor's retention, or acquisition as part of the assignment transaction or otherwise, of a subordinate equity interest or other provision of credit enhancement on terms substantially commensurate with market practices; (c) the fact that the electric public utility acts as the collector or servicer of transition bond charges; (d) the assignor's retention of bare legal title to bondable transition property for the purpose of servicing or supervising the servicing of such property and collections with respect thereto; or (e) treatment of such transfer as a financing for federal, State or local tax purposes or financial accounting purposes.

b. Such transfer shall be perfected against any third party when:

(1) The board has issued a bondable stranded costs rate order with respect to such bondable transition property;

(2) Such agreement has been executed and delivered by the electric public utility or its assignee; and

(3) A financing statement has been filed with respect to the transfer of such bondable transition property in accordance with N.J.S.12A:9-501 et seq.

N.J. Rev. Stat. § 48:3-73. Successors to electric public utilities; performance and obligations

Any successor to an electric public utility, whether pursuant to any bankruptcy, reorganization or other insolvency proceedings or pursuant to any merger, consolidation or sale or transfer of assets of the electric public utility, by operation of law, as a result of electric power industry restructuring or otherwise, shall perform and satisfy all obligations and be entitled to the same rights of its predecessor electric public utility under this act or the bondable stranded costs rate order or any contract entered into pursuant to this act in the same manner and to the same extent as such predecessor electric public utility, including, but not limited to, charging, collecting, receiving and paying to the person entitled thereto the revenues in respect of the transition bond charges relating to the bondable transition property. Bondable transition property, and any payments in respect to bondable transition property, including, without limitation, transition bond charges, shall not be subject to any setoffs, counterclaims, surcharges or defenses by the electric public utility, any customer, or any other person, in connection with the bankruptcy, insolvency or default of the electric public utility or otherwise.

N.J. Rev. Stat. § 48:3-74. Bondable stranded costs rate order; no application required

Notwithstanding any of the provisions of this act, an electric public utility shall not be obligated under this act to apply to the board for any bondable stranded costs rate order, consent to the terms of any bondable stranded costs rate order, or sell, transfer or pledge any bondable transition property, or issue transition bonds in connection therewith.

The consideration or approval by the board of a petition by any electric public utility under this act, including the periodic adjustment provided in subsection b. of section 15 of this act shall be wholly separate from and shall not be utilized in the board's consideration of any other ratemaking or other proceeding involving the electric public utility except as otherwise provided in this act.

N.J. Rev. Stat. § 48:3-75. Expedited judicial review of bondable stranded costs rate orders

In order to maximize the rate savings to customers of the electric public utility under a bondable stranded costs rate order, which order may be time-sensitive because financial market conditions may affect the feasibility and terms of transition bonds approved for issuance therein, the parties involved in proceedings resulting in such an order shall attempt to expedite judicial review pursuant to the following procedures:

a. Upon the issuance of a bondable stranded costs rate order, the board shall forthwith cause a certified copy of such order to be served upon each party entitled thereto. The electric public utility shall, within 10 days of such service upon it, file with the board its written consent to such order or its objections thereto.

b. Any party to the proceedings resulting in a bondable stranded costs rate order who claims to be aggrieved by such order, including but not limited to any electric public utility which has withheld its consent and objected thereto or any financing entity interested therein, may seek judicial review of such order in accordance with the applicable Rules Governing the Courts of the State of New Jersey and the provisions of this act. Such judicial review shall be the exclusive remedy for the parties involved in a proceeding resulting in a bondable stranded costs rate order and no petition for rehearing to the board shall be made or entertained.

c. Any party seeking judicial review under this section shall file a motion for expedited consideration of the appeal before any appellate court in which an appeal may be pending on the ground that acceleration is warranted because the subject of the appeal involves matters of important public interest.

N.J. Rev. Stat. § 48:3-76. Bondable transition property as accounts; secured parties

a. For purposes of this act, and the Uniform Commercial Code--Secured Transactions, N.J. Rev. Stat.12A:9-101 et seq., bondable transition property, as defined in N.J. Rev. Stat. 12A:9-102 (a) (8.1), shall constitute an account. For purposes of this act, and the Uniform Commercial Code--Secured Transactions, N.J. Rev. Stat.12A:9-101 et seq., bondable transition property shall be in existence whether or not the revenues or proceeds in respect thereof have accrued, in accordance with subsection c. of section 22 of this act. The validity, perfection or priority of any security interest in bondable transition property shall not be defeated or adversely affected by changes to the bondable stranded costs rate order or to the transition bond charges payable by any customer. Any description of bondable transition property in a security agreement or other agreement or a financing statement shall be sufficient if it refers to the bondable stranded costs rate order establishing the bondable transition property.

b. In addition to the other rights and remedies provided or authorized by this act, and by the Uniform Commercial Code--Secured Transactions, N.J. Rev. Stat.12A:9- 101 et seq., when a debtor is in default under a security agreement and the collateral is bondable transition property, then upon application by the secured party, the board or any court of competent jurisdiction shall order the sequestration and payment to the secured party of all collections and other proceeds of such bondable transition property up to the value of the property. In the event of any conflicts, priority among pledgees, transferees or secured parties shall be determined under N.J. S.12A:9-101 et seq. The secured party shall account to the debtor for any surplus and, unless otherwise agreed, the debtor shall be liable for any deficiency.

N.J. Rev. Stat. § 48:3-77. Power generated at on-site generation facilities; charges

a. Whenever an on-site generation facility produces power that is not consumed by the on-site customer, and that power is delivered to an off-site end-use customer in this State, all the following charges shall apply to the sale or delivery of such power to the off-site customer:

(1) The societal benefits charge or its equivalent, imposed pursuant to section 12 of this act;

(2) The market transition charge or its equivalent, imposed pursuant to section 13 of this act; and

(3) The transition bond charge or its equivalent, imposed pursuant to section 18 of this act.

b. None of the following charges shall be imposed on the electricity sold solely to the on-site customer of an on-site generating facility, except pursuant to subsection c. of this section:

(1) The societal benefits charge or its equivalent, imposed pursuant to section 12 of this act;

(2) The market transition charge or its equivalent, imposed pursuant to section 13 of this act; and

(3) The transition bond charge or its equivalent, imposed pursuant to section 18 of this act.

c. Upon finding that generation from on-site generation facilities installed subsequent to the starting date of retail competition as provided in subsection a. of section 5 of this act has, in the aggregate, displaced customer purchases from an electric public utility by an amount such that the kilowatt hours distributed by the electric public utility have been reduced to an amount equal to 92.5 percent of the 1999 kilowatt hours distributed by the electric public utility, the board shall impose, except as provided in subsection d. of this section, the charges listed in subsections a., b., and c. of this section on the on-site customer. Such charges shall not be levied on any power consumption that is displaced by an on-site generation facility that is installed before the date of such finding:

(1) The societal benefits charge or its equivalent, imposed pursuant to section 12 of this act;

(2) The market transition charge or its equivalent, imposed pursuant to section 13 of this act; and

(3) The transition bond charge or its equivalent, imposed pursuant to section 18 of this act.

d. Notwithstanding the provisions of subsection c. of this section, a charge shall not be imposed on power consumption by the on-site customer that is derived from an on-site generation facility:

(1) That the on-site customer or its agent installed on or before the effective date of this act, including any expansion of such a facility for the continued provision of on-site power consumption by the same on-site customer that occurs after the effective date of this act; or

(2) For which the on-site customer or its agent has made, on or before the effective date of this act, substantial financial and contractual commitments in planning and development, including having applied for any appropriate air permit from the Department of Environmental Protection, including any expansion of such a facility for the continued provision of on-site power consumption by the same on-site customer that occurs after the effective date of this act.

N.J. Rev. Stat. § 48:3-78. Electric power supplier licensing; requirements

a. A person shall not offer to provide or provide electric generation service to retail customers in this State unless that person has applied for and obtained from the board, pursuant to standards adopted by the board, an electric power supplier license. Persons providing such services on the effective date of this act shall have 120 days to apply for and receive the requisite license.

b. The board shall issue a license to an electric power supplier that is in compliance with the licensing standards adopted pursuant to subsection c. of this section. A license shall expire one year from the date of issuance unless the holder thereof pays to the board, within 30 days before the expiration date, a renewal fee accompanied by a renewal application on a form prescribed by the board. If a licensee has made, in accordance with this section and any applicable board rules or regulations, timely and sufficient application for renewal, the license shall not expire until the application has been reviewed and acted upon by the board. Nothing in this section shall limit the authority of the board to deny, suspend or revoke a license at any time, consistent with the provisions of this act.

c. Notwithstanding any provisions of the ?Administrative Procedure Act, " P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety, after notice, provision of the opportunity for comment, and public hearing, interim electric power supplier licensing standards within 90 days of the effective date of this act. Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act." The standards shall include, but need not be limited to, the following requirements that an electric power supplier:

(1) Register with the board, which shall include the filing of basic information pertaining to the supplier, such as name, address, telephone number, and company background and profile, and a list of the services or products offered by the supplier. A supplier shall provide annual updates of this information to the board. The registration shall also include:

(a) Evidence of financial integrity;

(b) Information on any disciplinary proceedings or actions by law enforcement authorities in which the electric power supplier, its subsidiaries, affiliates or parent has been involved in this State or any other states;

(c) The ownership interests of the supplier including the interests owned by the supplier and the interests owning the supplier;

(d) The name and address of the in-State agent of the supplier that is authorized to receive service of process;

(e) The name and address of the in-State customer service agent for the supplier; and

(f) The quantity of retail electric sales made in this State during the 12 months preceding the application.

(2) Agree to meet all reliability standards established by the Mid-Atlantic Area Council of the North American Electric Reliability Council or its successor, the PJM Interconnection, L.L.C. independent system operator or its successor, the Federal Energy Regulatory Commission, the board, or any other state, regional, federal or industry body with authority to establish reliability standards. The board may establish specific standards applicable to electric power suppliers to ensure the adequacy of electric power capacity, if it determines that standards established by any other state, regional, federal or industry bodies are not sufficient to assure the provision of safe, adequate, proper and reliable electric generation service to retail customers in this State. Such reliability standards shall ensure bulk power system operations and security, and shall ensure the adequacy of electric power capacity necessary to meet retail loads;

(3) Maintain an office within this State for the purposes of accepting service of process, maintaining such records as the board requires and ensuring accessibility to the board, consumers and electric public utilities;

(4) Maintain a surety bond under terms and conditions as determined by the board;

(5) Provide a description of the products and services to be rendered;

(6) Comply with such specific standards of conduct for electric power suppliers as the board shall adopt; and

(7) Provide through legal certification by an officer of the electric power supplier such information as the board or its staff shall require to assist the board in making any determination concerning revocation, suspension, issuance or renewal of the supplier's license pursuant to section 32 of this act.

d. An electric public utility shall:

(1) Incorporate by reference the board's licensing requirements in its tariffs for transmission and distribution service;

(2) Apply the licensing requirements and other conditions for access to the transmission and distribution system uniformly to all electric power suppliers; and

(3) Report alleged violations of the board's licensing requirements of which it becomes aware to the board.

e. The board shall establish an alternative dispute resolution program to resolve any licensure or access dispute between an electric power supplier and an electric public utility. The board may establish reasonable fees, not to exceed actual costs, for the provision of alternate dispute resolution services. If informal resolution of the dispute is unsuccessful, the board shall adjudicate the dispute as a contested case pursuant to the "Administrative Procedure Act."

f. The board shall monitor the retail supply market in this State, and shall consider information available from the PJM Interconnection, L.L.C. independent system operator or its successor with respect to the conduct of electric power suppliers. The board shall monitor proposed acquisitions of electric generating facilities by electric power suppliers as it deems necessary, in order to ascertain whether an electric power supplier has or is proposed to have control over electric generating facilities of sufficient number or strategic location to charge non-competitive prices to retail customers in this State. The board shall have the authority to deny, suspend or revoke an electric power supplier's license, after hearing, if it determines that an electric power supplier has or may acquire such control, or if the electric power supplier's violations of the rules, regulations or procedures of the PJM Interconnection, L.L.C. independent system operator or its successor may adversely affect the reliability of service to retail customers in this State or may result in retail customers being charged non-competitive prices.

g. The board may establish safety and service quality standards for electric power suppliers, and nothing in this act shall limit the authority of the board to promulgate such safety or service quality standards or to resolve complaints regarding the quality of electric generation service.

h. The board may establish, by written order pursuant to subsection c. of this section or by rule, a licensure fee to cover the costs of licensing electric power suppliers. The fee shall include a reasonable surcharge to fund a consumer education program in this State established pursuant to section 36 of this act.

i. Any provision of this act to the contrary notwithstanding, any person acting as an energy agent shall be required to register with the board. This registration shall include, but need not be limited to, the name, address, telephone number, and business affiliation or profile of the energy agent, evidence of financial integrity as determined by the board, and evidence of knowledge of the energy industry. This registration shall be updated annually. Nothing in this subsection shall be construed to limit or exempt an energy agent from liability under any other law pertaining to any activity which an energy agent may engage in.

N.J. Rev. Stat. § 48:3-79. Gas supplier licensing; requirements

a. A person shall not offer to provide or provide gas supply service to retail customers in this State unless that person has applied for and obtained from the board, pursuant to standards adopted by the board, a gas supplier license. A person providing such services on the effective date of this act shall have 120 days to apply for and receive the requisite license.

b. The board shall issue a license to a gas supplier that is in compliance with the licensing standards adopted pursuant to subsection c. of this section. A license shall expire one year from the date of issuance unless the holder thereof pays to the board, within 30 days before the expiration date, a renewal fee accompanied by a renewal application on a form prescribed by the board.

c. Notwithstanding any provisions of the ?Administrative Procedure Act, " P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, interim gas supplier licensing standards within 90 days of the effective date of this act. Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act." The standards shall include, but need not be limited to, the following requirements that a gas supplier:

(1) Register with the board, which shall include the filing of basic information pertaining to the gas supplier, such as name, address, telephone number, and company background and profile, and a list of the services or products offered by the gas supplier. A gas supplier shall provide annual updates of this information to the board. The registration shall also include:

(a) Evidence of financial integrity;

(b) Information on any disciplinary proceedings or actions by law enforcement authorities in which the gas supplier, its subsidiaries, affiliates or parent has been involved in this State or any other states;

(c) The ownership interests of the gas supplier including the interests owned by the gas supplier and the interests owning the gas supplier;

(d) The name and address of the in-State agent of the gas supplier that is authorized to receive service of process;

(e) The name and address of the in-State customer service agent for the gas supplier;

(f) The quantity of retail gas sales made in this State during the 12 months preceding the application; and

(g) A list of the services or products offered by the gas supplier;

(2) Agree to meet all reliability standards established by the board or any other state, regional, federal or industry body with authority to establish reliability standards. The board may establish specific standards applicable to gas suppliers to ensure the adequacy of gas capacity, if it determines that standards established by any other state, regional, federal or industry bodies are not sufficient to assure the provision of safe, adequate, proper and reliable gas supply service to retail customers in this State;

(3) Maintain an office within this State for purposes of accepting service of process, maintaining such records as the board requires and ensuring accessibility to the board, consumers and gas public utilities;

(4) Maintain a surety bond under terms and conditions approved by the board;

(5) Provide a description of the products and services to be rendered;

(6) Comply with such specific standards of conduct for gas suppliers as the board shall adopt; and

(7) Provide through legal certification by an officer of the gas supplier such information as the board or its staff shall require to assist the board in making any determination concerning revocation, suspension, issuance or renewal of the

gas supplier's license pursuant to section 32 of this act.

d. A gas public utility shall:

(1) Incorporate by reference the board's licensing requirements in its tariffs for distribution service;

(2) Apply the licensing requirements and other conditions for access to the distribution system uniformly to all gas suppliers;

(3) Not unreasonably deny a licensed gas supplier access to its distribution system; and

(4) Report alleged violations of the board's licensing requirements of which it becomes aware to the board.

e. The board shall establish an alternative dispute resolution program to resolve any licensure or access dispute between a gas supplier and a gas public utility. The board may establish reasonable fees, not to exceed actual costs, for the provision of alternate dispute resolution services. If informal resolution of the dispute is unsuccessful, the board shall adjudicate the dispute as a contested case pursuant to the "Administrative Procedure Act."

f. The board may establish safety and service quality standards for gas suppliers, and nothing in this act shall limit the authority of the board to promulgate such safety or service quality standards or to resolve complaints regarding the quality of gas supply service.

g. The board may establish, by written order pursuant to subsection c. of this section or by rule, a licensure fee to cover the costs of licensing gas suppliers. The fee shall include a reasonable surcharge to fund a consumer education program in this State established pursuant to section 36 of this act.

N.J. Rev. Stat. § 48:3-80. Investigative powers of the board

a. Whenever it shall appear to the board that an electric power supplier or a gas supplier has engaged in, is engaging in, or is about to engage in any act or practice that is in violation of this act, or when the board shall deem it to be in the public interest to inquire whether any such violation may exist, the board may exercise any of the following investigative powers:

(1) Require any person to file, on such form as may be prescribed, a statement or report in writing under oath, or otherwise, as to the facts and circumstances concerning the rendition of any service or conduct of any sale incidental to the discharge of this act;

(2) Examine under oath any person in connection with any act or practice subject to the requirements of this act;

(3) Inspect any premises from which an electric power supplier or a gas supplier conducts business;

(4) Examine any goods, ware, item or facility used in the supply of electric power or gas;

(5) Examine any record, book, document, account, electronic data or paper maintained by or for any electric power supplier or gas supplier;

(6) For the purpose of preserving evidence of an unlawful act or practice, pursuant to an order of the Superior Court, impound any record, book, document, account, paper, electronic data, goods, ware, item or facility used or maintained by or for any electric power supplier or gas supplier in the regular course of business. In such cases as may be necessary, the Superior Court may, on application of the board, issue an order sealing items or material subject to this paragraph.

b. If any person shall fail or refuse to file any statement or report or refuse access to premises from which an electric power supplier or a gas supplier conducts business in any lawfully conducted investigative matter or fail to obey a subpoena issued pursuant to this act, the board may apply to the Superior Court and obtain an order:

(1) Adjudging such person in contempt of court;

(2) Granting such other relief as may be required; or

(3) Suspending the license of any such person unless and until compliance with the subpoena or investigative demand is effected.

c. Whenever the board finds that a violation by an electric power supplier or a gas supplier of this act, including the unlicensed supplying of electric power or gas, or of any rule or regulation adopted by the board pursuant thereto, has occurred, is occurring or will occur, the board, in addition to any other proceeding authorized by law, may seek and obtain in a summary proceeding in the Superior Court an injunction prohibiting such act or practice.

N.J. Rev. Stat. § 48:3-81. Disciplinary powers of the board

a. The board may revoke, suspend, or refuse to issue or renew an electric power supplier's license or a gas supplier's license at any time upon a finding that the supplier:

(1) Has obtained a license through fraud, deception or misrepresentation;

(2) Has engaged in the use or employment of dishonesty, fraud, deception, misrepresentation, false promise or false pretense;

(3) Has engaged in gross negligence or gross incompetence;

(4) Has engaged in repeated acts of negligence or incompetence;

(5) Has engaged in misconduct as may be determined by the board;

(6) Has been convicted of any crime involving moral turpitude or any crime relating adversely to the activity regulated by the board, has not fulfilled the licensure requirements or is not in compliance with the safety and service quality standards adopted by the board. For the purpose of this subsection, a plea of guilty, *non vult, nolo contendere* or any other such disposition of alleged criminal activity shall be deemed a conviction;

(7) Has violated any consumer protection law or regulation in this State or any other state or has had its authority to engage in supplying electric power or gas revoked or suspended by any other state, agency or authority for reasons consistent with this section;

(8) Has violated or failed to comply with the provisions of any law or regulation or order adopted by the board;

(9) Is incapable, for any good cause, of discharging the functions of an electric power supplier or a gas supplier in a manner consistent with the public health, safety and welfare; or

(10) Has repeatedly failed to submit completed applications, or parts of such applications, or documentation submitted in conjunction with such applications, required to be filed with the Department of Environmental Protection.

b. The board may, upon a duly verified application alleging an act or practice violating any provision of this act or any rule adopted pursuant thereto, enter a temporary order suspending or limiting any license issued by the board pending plenary hearing on an administrative complaint when the application made to the board and imminent danger to the public health, safety or welfare, and notice of such application is given to the licensee affected by such order.

N.J. Rev. Stat. § 48:3-82. Alternative disciplinary powers of the board

a. In addition or as an alternative, as the case may be, to revoking, suspending or refusing to issue or to renew the license of an electric power supplier or a gas supplier, the board may, after notice and opportunity for a hearing:

(1) Issue a letter of warning, reprimand or censure with regard to any act, conduct or practice that in the judgment of the board, upon consideration of all relevant facts and circumstances, does not warrant the initiation of formal action;

(2) Assess a civil penalty pursuant to section 34 of this act;

(3) Order that any person violating any provision of this act or any rule adopted pursuant to this act cease and desist from future violations thereof or take affirmative corrective action as may be necessary with regard to any act or practice found unlawful by the board;

(4) Order any person found to have violated any provision of this act or any rule adopted pursuant thereto to restore to any person aggrieved by an unlawful act or practice any moneys or property, real or personal, or the equivalent value of any property, real or personal, acquired by means of such act or practice; except that the board shall not order restoration in a dollar amount greater than the total value of those monies or property received by a licensee or a licensee's agent or any other person violating the act or rule.

b. In any administrative proceeding commenced on a complaint alleging a violation of this act or of a rule adopted pursuant thereto, the board or the board secretary may issue subpoenas to compel the attendance of witnesses or the production of electronic data, books, records, or documents at the hearing on the complaint.

c. In any action brought pursuant to this act, the board or the court may order the payment of costs for the use of the State.

d. Pursuit of any remedy specified in this section shall not preclude the pursuit of any other remedy, including any civil remedy for damage, provided by any other law. Administrative and judicial remedies provided in this section may be pursued simultaneously.

N.J. Rev. Stat. § 48:3-83. Civil penalties

Any person who violates any provision of this act shall be liable for a civil penalty of not more than $5,000 for the first offense, except for a violation of section 37 of this act, for which a person shall be liable for a civil penalty of not more than $10,000 for the first offense, and not more than $25,000 for the second and each subsequent offense, for each day that the violation continues. Any civil penalty which may be imposed pursuant to this section may be compromised by the board. In determining the amount of the penalty, or the amount agreed upon in compromise, the board shall consider: the nature, circumstances and gravity of the violation; the degree of the violator's culpability; any history of prior violations; the prospective effect of the penalty on the ability of the violator to conduct business; any good faith effort on the part of the violator in attempting to achieve compliance; the violator's ability to pay the penalty; and other factors the board determines to be appropriate. The amount of the penalty when finally determined, or the amount agreed upon in compromise, may be deducted from any sums owing by the State to the person charged, or may be recovered, if necessary, in a summary proceeding pursuant to "the penalty enforcement law," N.J. Rev. Stat.2A:58-1 et seq. The Superior Court shall have jurisdiction to enforce the provisions of "the penalty enforcement law" in connection with this act.

N.J. Rev. Stat. § 48:3-84. Rights, remedies and prohibitions

a. The rights, remedies and prohibitions accorded by the provisions of this act are in addition to and cumulative of any right, remedy or prohibition accorded by the common law or any statute of this State and nothing contained herein shall be construed to deny, abrogate or impair any such common law or statutory right, remedy or prohibition. The

Attorney General and the Division of Consumer Affairs in the Department of Law and Public Safety shall continue to have the authority to enforce civil and criminal violations of the consumer fraud act, P.L.1960, c. 39 (C.56:8-1 et seq.) or any other applicable law, rule or regulation in connection with the activities of electric power suppliers and gas suppliers.

b. Administrative and judicial remedies provided in this act may be pursued simultaneously.

N.J. Rev. Stat. § 48:3-85. Interim consumer protection standards; disclosure of consumer proprietary information

a. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety, shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, interim consumer protection standards for electric power suppliers or gas suppliers, within 90 days of February 9, 1999, including, but not limited to, standards for collections, credit, contracts, authorized changes of an energy consumer's electric power supplier or gas supplier, for the prohibition of discriminatory marketing, for advertising and for disclosure. Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

(1) Contract standards shall include, but not be limited to, requirements that electric power supply contracts or gas supply contracts must conspicuously disclose the duration of the contract; state the price per kilowatt hour or per therm or other pricing determinant approved by the board; have the customer's written signature; the customer's electronic signature; an audio recording of a telephone call initiated by the customer; independent, third-party verification, in accordance with section 37 of P.L.1999, c. 23 (C.48:3-86), of a telephone call initiated by an electric power supplier, gas supplier or private aggregator; or such alternative forms of verification as the board, in consultation with the Division of Consumer Affairs, may permit for switching electric power suppliers or gas suppliers and for contract renewal; and include termination procedures, notice of any fees, and toll-free or local telephone numbers for the electric power supplier or gas supplier and for the board.

(2) Standards for the prohibition of discriminatory marketing standards shall provide at a minimum that a decision made by an electric power supplier or a gas supplier to accept or reject a customer shall not be based on race, color, national origin, age, gender, religion, source of income, receipt of public benefits, family status, sexual preference, or geographic location. The board shall adopt reporting requirements to monitor compliance with such standards.

(3) Advertising standards for electric power suppliers or gas suppliers shall provide, at a minimum, that optional charges to the consumer will not be added to any advertised cost per kilowatt hour or per therm, and that the only unit of measurement that may be used in advertisements is cost per kilowatt hour or per therm, unless otherwise approved by the board. If an electric power supplier or gas supplier does not advertise using cost per kilowatt hour or per therm, the electric power supplier or gas supplier shall provide, at the consumer's request, an estimate of the cost per kilowatt hour or per therm. Any optional charges to the consumer shall be identified separately and denoted as optional.

(4) Credit standards shall include, at a minimum, that the credit requirements used to make offer decisions must be the same for all residential customers and that electric power suppliers, gas suppliers and private aggregators not impose unreasonable income or credit requirements.

(5) Billing standards shall include, at a minimum, provisions prohibiting electric public utilities, gas public utilities, electric power suppliers and gas suppliers from charging a fee to residential customers for either the commencement or termination of electric generation service or gas supply service.

b. (1) Except as provided in paragraph (2) of this subsection, an electric power supplier, a gas supplier, an electric public utility, and a gas public utility shall not disclose, sell or transfer individual proprietary information, including, but not limited to, a customer's name, address, telephone number, energy usage and electric power payment history, to a third party without the consent of the customer.

(2)(a) An electric public utility or a gas public utility may disclose and provide, in an electronic format, which may include a CD rom, diskette, and other format as determined by the board, without the consent of a residential customer, a residential customer's name, rate class, and account number, to a government aggregator that is a municipality or a county, or to an energy agent acting as a consultant to a government aggregator that is a municipality or a county, if the customer information is to be used to establish a government energy aggregation program pursuant to sections 42, 43 and 45 of P.L.1999, c. 23 (C.48:3-91; 48:3-92; and 48:3-94). The number of residential customers and their rate class, and the load profile of non-residential customers who have affirmatively chosen to be included in a government energy aggregation program pursuant to paragraph (3) of subsection a. of section 45 of P.L.1999, c 23 (C.48:3-94) may be disclosed pursuant to this paragraph prior to the request by the government aggregator for bids pursuant to paragraph (1) of subsection b. of section 45 of P.L.1999, c. 23 (C.48:3-94), and the name, address, and account number of a residential customer and the name, address and account number of non-residential customers who have affirmatively chosen to be included in a government energy aggregation program pursuant to paragraph (3) of subsection a. of section 45 of P.L.1999, c. 23 (C.48:3-94) may be disclosed pursuant to this paragraph upon the awarding of a contract to a licensed power supplier or licensed gas supplier pursuant to paragraph (2) of subsection b. of section 45 of P.L.1999, c. 23. Any customer information disclosed pursuant to this paragraph shall not be considered a government record for the purposes of, and shall be exempt from the provisions of P.L.2001, c. 404.

(b) An electric public utility or a gas public utility disclosing customer information pursuant to this paragraph shall exercise reasonable care in the preparation of this customer information, but shall not be responsible for errors or omissions in the preparation or the content of the customer information.

(c) Any person using any information disclosed pursuant to this paragraph for any purpose other than to establish a government energy aggregation program pursuant to sections 42, 43 and 45 of P.L.1999, c. 23 (C. 48:3-91; 48:3-92; and 48:3-94) shall be subject to the provisions of section 34 of P.L.1999, c. 23 (C.48:3-83).

(d) The role of an electric public utility or a gas public utility in a government energy aggregation program established pursuant to P.L.1999, c. 23 shall be limited to the provisions of this paragraph.

(3) Whenever any individual proprietary information is disclosed, sold or transferred, pursuant to paragraph (1) or paragraph (2) of subsection b. of this section, it shall be used only for the provision of continued electric generation service, electric related service, gas supply service or gas related service to that customer. In the case of a transfer or sale of a business, customer consent shall not be required for the transfer of customer proprietary information to the subsequent owner of the business for maintaining the continuation of such services.

(4) Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall, within 90 days of the effective date of P.L.2003, c. 24 (C.48:3-93.1 et al), review existing regulations including, without limitation, Chapter 4 of Title 14 of the New Jersey Administrative Code (Energy Competition Standards), to determine their consistency with the provisions of section 6 of P.L.1999, c. 23 (C.48:3-85), section 43 of P.L.1999, c. 23 (C.48:3-92) and section 45 of P.L.1999, c. 23 (C.48:3-94), shall repeal or modify any regulations that are inconsistent with the provisions thereof and shall adopt regulations and standards implementing the provisions thereof permitting disclosure of customer information without the consent of the customer including, without limitation, provisions for the development of a board-approved agreement between the disclosing party and the receiving party and the creation of a mechanism for the recovery by the disclosing electric public utility or gas public utility of its reasonable incremental costs of providing such information if such costs are not covered in an existing third party supplier agreement.

(5) An electric power supplier, a gas supplier, a gas public utility or an electric public utility may use individual proprietary information that it has obtained by virtue of its provision of electric generation service, electric related service, gas supply service or gas related service to:

(a) Initiate, render, bill and collect for such services to the extent otherwise authorized to provide billing and collection services;

(b) Protect the rights or property of the electric power supplier, gas supplier or public utility; and

(c) Protect consumers of such services and other electric power suppliers, gas suppliers or electric and gas public utilities from fraudulent, abusive or unlawful use of, or subscription to, such services.

c. The board shall establish and maintain a database for the purpose of recording customer complaints concerning electric and gas public utilities, electric power suppliers, gas suppliers, private aggregators, and energy agents.

d. The board, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety, shall establish, or cause to be established, a multi-lingual electric and gas consumer education program. The goal of the consumer education program shall be to educate residential, small business, and special needs consumers about the implications for consumers of the restructuring of the electric power and gas industries. The consumer education program shall include, but need not be limited to, the dissemination of information to enable consumers to make informed choices among available electricity and gas services and suppliers, and the communication to consumers of the consumer protection provisions of this act.

The board shall ensure the neutrality of the content and message of advertisements and materials.

The board shall promulgate standards for the recovery of consumer education program costs from customers which include reasonable measures and criteria to judge the success of the program in enhancing customer understanding of retail choice.

e. (Deleted by amendment, P.L.2003, c. 24)

N.J. Rev. Stat. § 48:3-86. Unauthorized changes of gas or electric supplier

a. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety, shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, interim standards for electric power suppliers or gas suppliers, within 90 days of February 9, 1999, to prevent and establish penalties for unauthorized changes of a consumer's electric power supplier or gas supplier, a practice commonly known as "slamming." Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

b. Standards for the prohibition of unauthorized changes in a customer's electric power supplier or gas supplier shall include:

(1) An electric power supplier, an electric public utility, a gas supplier or a gas public utility shall not cause an unauthorized change in a customer's electric power supplier or gas supplier, a practice known as "slamming." A change in a customer's electric power supplier or gas supplier shall be deemed to be unauthorized unless the customer has done so affirmatively and voluntarily and the supplier has obtained the customer's approval , which approval shall be evidenced by the customer's written signature; the customer's electronic signature; an audio recording of a telephone call initiated by the customer; independent, third-party verification, in accordance with paragraph (2) of this subsection, of a telephone call initiated by an electric power supplier, electric public utility, gas supplier or gas public utility; or such alternative forms of verification as the board, in consultation with the Division of Consumer Affairs, may permit;

(2) (a) A company performing independent, third-party verification shall: (i) be independent from the entity that seeks to provide the new service; (ii) not be directly or indirectly managed, controlled, directed or owned, wholly or in part, by the entity that seeks to provide the new service, or by any affiliate of that entity; (iii) operate from facilities physically separate from those of the entity that seeks to provide the new service; and (iv) not derive any commission or compensation based upon the number of sales confirmed;

(b) A company performing independent, third-party verification shall obtain a customer's oral confirmation regarding the change and shall record that confirmation by obtaining appropriate verification data. The record shall be available to the customer upon request. Information obtained from a customer through confirmation shall not be used for marketing purposes;

(3) An electric power supplier, an electric public utility, a gas supplier or a gas public utility shall not fail to cause a change in a customer's electric power supplier or gas supplier, within a period of time determined to be appropriate by the board, when a supplier or utility is in receipt of a change order provided that such change order has been received in a manner that complies with federal and State rules and regulations, including as provided in this subsection;

(4) The acts of an agent of an electric power supplier, an electric public utility, a gas supplier or a gas public utility shall be considered the acts of the electric power supplier, electric public utility, gas supplier or gas public utility.

c. A customer's new electric power supplier, electric public utility, gas supplier or gas public utility shall notify the customer of the change in the customer's electric or gas supplier within 30 days in a manner to be determined by the board.

d. Bills to customers from an electric power supplier, electric public utility, gas supplier or gas public utility shall contain the name and telephone number of each supplier for whom billing is provided, and any other information deemed applicable by the board.

e. In addition to any other penalties, fines or remedies authorized by law, any electric power supplier, electric public utility, gas supplier or gas public utility that violates this section and collects charges for electric power supply or gas supply services from a customer or through an entity providing customer account services shall be liable to the electric power supplier, electric public utility, gas supplier or gas public utility previously selected by the customer in an amount equal to all charges paid by the customer after such violation in accordance with such procedures as the board may prescribe. Any electric power supplier, electric public utility, gas supplier or gas public utility that violates this section shall also be liable for a civil penalty pursuant to section 34 of P.L.1999, c. 23 (C.48:3-83); and the board is hereby authorized to revoke the license of any entity that violates this section.

N.J. Rev. Stat. § 48:3-87. Emissions disclosure requirements and portfolio standards

a. The board shall require an electric power supplier or basic generation service provider to disclose on a customer's bill or on customer contracts or marketing materials, a uniform, common set of information about the environmental characteristics of the energy purchased by the customer, including, but not limited to:

(1) Its fuel mix, including categories for oil, gas, nuclear, coal, solar, hydroelectric, wind and biomass, or a regional average determined by the board;

(2) Its emissions, in pounds per megawatt hour, of sulfur dioxide, carbon dioxide, oxides of nitrogen, and any other pollutant that the board may determine to pose an environmental or health hazard, or an emissions default to be determined by the board; and

(3) Any discrete emission reduction retired pursuant to rules and regulations adopted pursuant to P.L.1995, c. 188.

b. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, in consultation with the Department of Environmental Protection, after notice and opportunity for public comment and public hearing, interim standards to implement this disclosure requirement, including, but not limited to:

(1) A methodology for disclosure of emissions based on output pounds per megawatt hour;

(2) Benchmarks for all suppliers and basic generation service providers to use in disclosing emissions that will enable consumers to perform a meaningful comparison with a supplier's or basic generation service provider's emission levels; and

(3) A uniform emissions disclosure format that is graphic in nature and easily understandable by consumers. The board shall periodically review the disclosure requirements to determine if revisions to the environmental disclosure system as implemented are necessary.

Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

c. (1) The board may adopt, in consultation with the Department of Environmental Protection, after notice and opportunity for public comment, an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, upon a finding that:

(a) The standard is necessary as part of a plan to enable the State to meet federal Clean Air Act or State ambient air quality standards; and

(b) Actions at the regional or federal level cannot reasonably be expected to achieve the compliance with the federal standards.

(2) The board shall adopt an emissions portfolio standard applicable to all electric power suppliers and basic generation service providers, if two other states in the PJM power pool comprising at least 40 percent of the retail electric usage in the PJM Interconnection, L.L.C. independent system operator or its successor adopt such standards.

d. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, interim renewable energy portfolio standards that shall require:

(1) that two and one-half percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider be from Class I or Class II renewable energy sources; and

(2) beginning on January 1, 2001, that one-half of one percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider be from Class I renewable energy sources. The board shall increase the required percentage for Class I renewable energy sources so that by January 1, 2006, one percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider shall be from Class I renewable energy sources and shall additionally increase the required percentage for Class I renewable energy sources by one-half of one percent each year until January 1, 2012, when four percent of the kilowatt hours sold in this State by each electric power supplier and each basic generation service provider shall be from Class I renewable energy sources.

An electric power supplier or basic generation service provider may satisfy the requirements of this subsection by participating in a renewable energy trading program approved by the board in consultation with the Department of Environmental Protection.

Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

e. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing:

(1) net metering standards for electric power suppliers and basic generation service providers. The standards shall require electric power suppliers and basic generation service providers to offer net metering at non-discriminatory rates to residential and small commercial customers that generate electricity, on the customer's side of the meter, using wind or solar photovoltaic systems for the net amount of electricity supplied by the electric power supplier or basic generation service provider over an annualized period. Where the amount of electricity generated by the customer-generator plus any kilowatt hour credits held over from the previous billing periods exceed the electricity

supplied by the electric power supplier or basic generation service provider, the electric power supplier or basic generation service provider, as the case may be, shall credit the customer for the excess kilowatt hours until the end of the annualized period at which point the customer-generator will be compensated for any remaining credits at the electric power supplier's or basic generation service provider's avoided cost of wholesale power. The board may authorize an electric power supplier or basic generation service provider to cease offering net metering whenever the total rated generating capacity owned and operated by net metering customer-generators statewide equals 0.1 percent of the State's peak electricity demand or the annual aggregate financial impact to electric power suppliers and basic generation service providers statewide, as determined by the board, exceeds $2,000,000, whichever is less; and

(2) safety and power quality interconnection standards for wind and solar photovoltaic systems that shall be eligible for net metering. Such standards shall take into consideration the standards of other states and the Institute of Electrical and Electronic Engineers and shall allow customers to use a single, non-demand, non-time differentiated meter.

Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

f. The board may assess, by written order and after notice and opportunity for comment, a separate fee to cover the cost of implementing and overseeing an emission disclosure system or emission portfolio standard, which fee shall be assessed based on an electric power supplier's or basic generation service provider's share of the retail electricity supply market.

N.J. Rev. Stat. § 48:3-88. Municipal electric corporations

a.

(1) A municipal system, or a rural electric cooperative, that was established prior to the effective date of P.L.1999, c. 23 (C.48:3-49 et seq.), shall not be subject to the provisions of P.L.1999, c. 23 except as provided in paragraph (2) of subsection a. of this section or subsection b. of this section.

(2) The governing body of a municipality that operates such a municipal system, or the board of directors of a rural electric cooperative, may require that system or cooperative, as the case may be, to implement retail choice.

b. (1) A municipal system subject to this section that serves retail electric power customers solely within the corporate limits of its municipality and that, on or after the effective date of P.L.2003, c. 248 (C.48: 3-88 et al.), is authorized by the governing body of the municipality to provide electric generation service beyond those corporate limits shall become licensed as an electric power supplier pursuant to section 29 of P.L.1999, c. 23 (C.48:3- 78) and shall be subject to the provisions of sections 31 through 38 of P.L.1999, c. 23 (C.48:3-80 through C.48:3-87) for the purpose of and to the extent of the provision of such electric generation service.

(2) A municipal system subject to this section that serves retail electric power customers beyond the corporate limits of its municipality and that, on or after the effective date of P.L.2003, c. 248 (C.48:3-88 et al.), is authorized by the governing body of the municipality to provide electric generation service beyond its franchise area shall become licensed as an electric power supplier pursuant to section 29 of P.L.1999, c. 23 (C.48:3- 78) and shall be subject to the provisions of sections 31 through 38 of P.L.1999, c. 23 (C.48:3-80 through C.48:3-87) for the purpose of and to the extent of the provision of such electric generation service.

(3) A rural electric cooperative subject to this section that, on or after the effective date of P.L.2003, c. 248 (C.48:3-88 et al.), is authorized by its board of directors to provide electric generation service beyond its franchise area shall become licensed as an electric power supplier pursuant to section 29 of P.L.1999, c. 23 (C.48:3-78) and shall be subject to the provisions of sections 31 through 38 of P.L.1999, c. 23 (C.48:3-80 through C.48:3-87) for the purpose of and to the extent of the provision of such electric generation service.

(4) A municipal system or rural electric cooperative that becomes licensed as an electric power supplier and otherwise subject to the provisions of P.L.1999, c. 23 (C.48:3-49 et seq.) pursuant to the provisions of this section shall, in conjunction with the provision of electric generation service, provide for retail choice for the retail electric power customers within its prior service or franchise area, as appropriate.

c. For the purposes of this section, "municipal system" means a municipality that provides light, heat or power pursuant to the provisions of R.S.40:62- 12 et seq.

N.J. Rev. Stat. § 48:3-89. Aggregation of services; State taxation

a. A private aggregator may enter into a contract with a licensed electric power supplier or a licensed gas supplier for the provision of any combination of electric generation service, electric related service, gas supply service or gas related service for business customers.

b. A government aggregator may enter into a contract with a licensed electric power supplier or a licensed gas supplier, as provided in section 42 of this act, for the provision of any combination of electric generation service, electric related service, gas supply service or gas related service for its own use or as combined with the use of other government aggregators in a manner provided by law.

c. For residential customers, gas and electric services cannot be bundled until the gas market is opened up for retail competition for that residential customer.

d. Aggregation of electric generation service or gas supply service by a government aggregator shall not be construed to constitute the formation of a municipal electric corporation or a municipal electric utility created subsequent to the effective date of this act solely for purposes of State taxation and shall not exempt the sale of such services or income from that sale from any tax to which the sale or income would otherwise be subject, including but not limited to the sales and use tax imposed pursuant to P.L.1966, c. 30 (C.54:32B-1 et seq.) and the corporation business tax imposed pursuant to P.L.1945, c. 162 (C.54:10A-1 et seq.).

N.J. Rev. Stat. § 48:3-90. Private aggregators; registration

a. A private aggregator shall register with the board, which shall include the filing of basic information pertaining to the supplier, such as name, address, telephone number, and company background and profile. A private aggregator shall provide annual updates of this information to the board. The registration shall also include evidence of financial integrity, as determined by the board, and evidence that the private aggregator has knowledge of the energy industry.

b. Any residential customer that elects to purchase electric generation service or gas supply service, after the implementation of gas unbundling pursuant to section 10 of P.L.1999, c. 23 (C.48:3-58), through a private aggregator must do so affirmatively and voluntarily, either through a written signature; the customer's electronic signature; an audio recording of a telephone call initiated by the customer; independent, third-party verification, in accordance with section 37 of P.L. 1999, c. 23 (C.48:3-86), of a telephone call initiated by a private aggregator; or such alternative forms of verification as the board, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety, may permit.

N.J. Rev. Stat. § 48:3-91. Government aggregators

a. Pursuant to the provisions of sections 42 through 45 of this act, a government aggregator may obtain: electric generation service, electric related service, gas supply service or gas related service, either separately or bundled, for its own facilities or with other government aggregators; and a government aggregator that is a county or municipality may contract for the provision of electric generation service or gas supply service, either separately or bundled, for the business and residential customers within the territorial jurisdiction of the government aggregator. Such a government aggregator may combine the need for its own facilities for electric generation service or gas supply service with that of business and residential customers.

b. A government aggregator shall purchase electric generation service and gas supply service only from licensed electric power suppliers and licensed gas suppliers.

c. The government aggregator shall enter into the contract for electric generation service, electric related service, gas supply service or gas related service for its own facilities or with other government aggregators under the provisions of the "Local Public Contracts Law," P.L.1971, c. 198 (C.40A:11-1 et seq.), the "Public School Contracts Law," N.J. Rev. Stat.18A:18A-1 et seq., the "County College Contracts Law," P.L.1982, c. 189 (C.18A:64A-25.1 et seq.), or the "Interlocal Services Act," P.L.1973, c. 208 (C.40:8A-1 et seq.), as applicable.

d. Nothing in this act shall preclude the State government or any State independent authority or State college from exercising authority to obtain electric generation service, electric related service, gas supply service or gas related service, either separately or bundled, for its own facilities on an aggregated basis.

e. Nothing in this section shall preclude a government aggregator from aggregating its own accounts for regulated utility services, including basic generation or gas service.

f. Nothing in this act shall preclude any interstate authority or agency from exercising authority to obtain electric generation service or gas supply service, either separately or bundled, for its own facilities in this State, including tenants in this State and other utility customers in this State at such facilities, on an aggregated basis. By exercising such authority, no interstate authority or agency shall be deemed to be a public utility pursuant to R.S. 48:1-1 et seq.; provided, however, that nothing in this act shall be construed to exempt such authority or agency from the payment of the market transition charge or its equivalent, imposed pursuant to section 13 of this act, the transition bond charge or its equivalent, imposed pursuant to section 18 of this act and any societal benefits charge or its equivalent, which may be imposed pursuant to section 12 of this act, to the same extent that other customers of an electric public utility pay such charges in conjunction with any transmission and distribution service provided by an electric public utility to the authority or agency.

g. Notwithstanding any other provision of this act to the contrary, a private aggregator that is a private institution of higher education may enter into a contract with a licensed electric power supplier other than a municipal system or rural electric cooperative for the provision of electric generation service or electric related service, either separately or bundled, including any private aggregator that is a four-year private institution of higher education which is located within the jurisdiction of a municipal system, or within the franchise area of a rural electric cooperative, as the case may be. The right hereunder of a four-year private institution of higher education to enter into a contract with a licensed electric power supplier other than the municipal system or rural electric cooperative shall be subject to the condition that the municipal system or rural electric cooperative shall have the right of first refusal to offer a competitive, market-based price for electric power. For the purposes of this subsection, "municipal system" means a municipality that provides light, heat or power pursuant to the provisions of R.S.40:62- 12 et seq.

h. The "New Jersey School Boards Association," established pursuant to N.J. Rev. Stat.18A:6-45, is authorized to serve as a government aggregator to obtain electric generation service, electric related service, gas supply service or gas related service, either separately or bundled, in accordance with the "Public School Contracts Law," N.J. Rev. Stat.18A:18A-1 et seq., for members of the association who wish to voluntarily participate.

i. Notwithstanding any provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, interim standards governing government energy aggregation programs. Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

j. No government aggregator shall implement the provisions of section 42, 43, 44, or 45 of this act, as appropriate, prior to the starting date of retail competition pursuant to section 5 of this act, or the date on which the board adopts interim standards pursuant to subsection i. of this section, whichever is earlier.

N.J. Rev. Stat. § 48:3-92. Government energy aggregation programs

Government energy aggregation programs shall be subject to the following provisions:

a. A contract between a government aggregator and a licensed electric power supplier or licensed gas supplier shall include the following provisions:

(1) The specific responsibilities of the government aggregator and the licensed electric power supplier or licensed gas supplier;

(2) The charges, rates, fees, or formulas to be used to determine the charges, rates or fees, to be charged to the energy consumers electing to receive electric generation service or gas supply service pursuant to the government energy aggregation program;

(3) The method and procedures to be followed by the licensed electric power supplier or licensed gas supplier to enroll and educate energy consumers concerning the provisions of the aggregation program;

(4) The proposed terms and conditions of a standard contract between energy consumers and the licensed electric power supplier or licensed gas supplier including, but not necessarily limited to:

(a) The allocation of the risks in connection with the provision of such services between the licensed electric power supplier or licensed gas supplier and the energy consumers receiving such services;

(b) The terms of the proposed contract;

(c) The allocation of the risks associated with circumstances or occurrences beyond the control of the parties to the contract;

(d) Default and remedies; and

(e) The allocation of any penalties that may be imposed by any electric public utility or gas public utility as a result of over-delivery of electricity or gas, under-delivery of electricity or gas, or non-performance by the licensed electric power supplier or licensed gas supplier;

(5) The use of government aggregator resources, equipment, systems or employees in connection with such services;

(6) The term of the contract with the government aggregator;

(7) A provision indemnifying and holding the government aggregator harmless from all liabilities, damages and costs associated with any contract between a resident of the government aggregator and the licensed electric power supplier or licensed gas supplier;

(8) The requirements for the provision of a performance bond by the licensed electric power supplier or licensed gas supplier, if so required by the government aggregator;

(9) Procedures to ensure that participation in the aggregation program is consistent with the provisions of this act and with rules and regulations adopted by the board;

(10) Terms and conditions applicable to consumer protection as provided in rules and regulations adopted by the board, in consultation with the Division of Consumer Affairs in the Department of Law and Public Safety;

(11) A requirement that certain communications between a licensed electric power supplier and a licensed gas supplier

and a customer be in a non-English language, as appropriate; and

(12) Such other terms and conditions as the government aggregator deems necessary.

b. The award of a contract for a government energy aggregation program shall be based on the most advantageous proposal, price and other factors considered. The governing body shall only award a contract for service to residential customers where the rate is the same as or lower than the price of basic generation service pursuant to section 9 of P.L.1999, c. 23 (C.48:3-57), plus the pro-rata value of the cost of compliance with the renewable energy portfolio standards imposed pursuant to this act derived from a non-utility generation contract with an electric public utility and transferred by the electric public utility to a supplier of basic generation service or basic gas supply service pursuant to section 10 of P.L.1999, c. 23 (C.48:3-58), as determined by the board. The governing body may award a contract for electric generation service where the rate is higher than the price of basic generation service as determined by the board pursuant to section 9 of P.L.1999, c. 23, plus the pro-rata value of the cost of compliance with the renewable energy portfolio standards imposed pursuant to this act derived from a non-utility generation contract with an electric public utility and transferred by the electric public utility to a supplier of basic generation service, provided that the award is for electricity the percentage of which that is derived from verifiable Class I or Class II renewable energy as defined pursuant to section 3 of P.L.1999, c. 23 (C.48:3-51) is greater than the percentage of Class I and Class II renewable energy required pursuant to subsection d. of section 38 of P.L.1999, c. 23 (C.48:3-87), and that the customers are informed, in a manner determined by the board secretary, that such a higher rate is under consideration by the governing body.

c. No concession fees, finders' fees, or other direct monetary benefit shall be paid to any government aggregator by, or on behalf of, a licensed electric power supplier or licensed gas supplier or broker or energy agent as a result of the contract.

d. A licensed electric power supplier or licensed gas supplier shall be subject to the prohibitions against political contributions in accordance with the provisions of R.S.19:34-45.

e. A government aggregator may enter into more than one contract for the provision of electric generation service and gas supply service, provided, however that the governing body indicates in each contract which is the default provider if a customer does not choose one of the providers.

f. A county government acting as a government aggregator shall not enter into a contract for the provision of a government energy aggregation program that is in competition with any existing contract of any government aggregator within its territorial jurisdiction.

(1) A county government may enter into a contract for a government energy aggregation program only if one or more constituent municipalities in the county adopt an ordinance authorizing the county to enter into such a contract.

(2) A county government energy aggregation program shall only be conducted for residential and business customers located within the constituent municipalities that have approved participation in the county's government energy aggregation program.

N.J. Rev. Stat. § 48:3-93. Repealed by L.2003, c. 24, § 7, eff. Feb. 27, 2003

The repealed section, relating to participation in government energy aggregation programs, was derived from L.1999, c. 23, § 43.

N.J. Rev. Stat. § 48:3-93.1. Programs established; definitions

A government aggregator that is a municipality or a county may establish and operate a government energy aggregation program pursuant either to the provisions of the rules and regulations adopted by the Board of Public

Utilities pursuant to section 2 of P.L.2003, c. 24 (C.48: 3-93.2) or to the provisions of P.L.1999, c. 23 (C.48:3-49 et seq.). As used in this section "government aggregator" and " government energy aggregation program" shall have the same meaning as set forth in section 3 of P.L.1999, c. 23 (C.48:3-51).

N.J. Rev. Stat. § 48:3-93.2. Rules and regulations

a. The provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary notwithstanding, within 90 days of the effective date of P.L.2003, c. 24 (C.48:3-93.1 et al) the Board of Public Utilities shall adopt rules and regulations authorizing an electric public utility or a gas public utility, upon the request of the governing body of a county or municipality, to assist a government aggregator that is a municipality or a county in establishing a government energy aggregation program. The rules and regulations adopted pursuant to this section shall be effective as rules and regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and shall, thereafter, be amended, adopted or readopted by the board pursuant to the provisions of the "Administrative Procedure Act." The rules and regulations adopted pursuant to this section shall set forth a process for the establishment of a government energy aggregation that (1) requires a government aggregator that is a municipality or a county to establish a government energy aggregation program by ordinance or resolution, as appropriate, and to award a contract for the government energy aggregation program to a licensed electric power supplier or licensed gas supplier pursuant to the "Local Public Contracts Law," P.L.1971, c. 198 (C.40A:11-1 et seq.), provided, however, that such an award may be made on the basis of the most advantageous proposal, price and other factors considered; (2) includes residential customers on an opt- out basis prior to the solicitation of bids from a licensed electric power supplier or licensed gas supplier and non-residential customers on an opt-in basis; (3) requires an electric public utility or gas public utility, as the case may be, to notify utility customers, after the adoption of an ordinance or resolution, of the proposed government energy aggregation program and of the customer's right to decline to participate in the program; (4) requires an electric public utility or a gas public utility, as the case may be, to provide appropriate customer information to a government aggregator that is a municipality or a county after the government aggregator has awarded a contract for a government energy aggregation program to a licensed electric power supplier or licensed gas supplier, as the case may be; (5) provides that an electric public utility or a gas public utility shall exercise reasonable care in the disclosure of customer information pursuant to this section but shall not be responsible for errors or omissions in the preparation or the content of the customer information; (6) provides that an electric public utility or gas public utility shall not disclose to any governing body, licensed electric power supplier or licensed gas supplier the name, load profile, or any other customer information about a non-residential customer prior to that non-residential customer opting in to the government energy aggregation program; and (7) authorizes electric public utilities and gas public utilities to prioritize requests made by governing bodies pursuant to this section.

b. The rules and regulations adopted by the board pursuant to this section shall provide for the recovery by an electric public utility or a gas public utility of all reasonable costs incurred by the electric public utility or gas public utility in implementing a government energy aggregation and all reasonable costs incurred in assisting a governing body considering a government energy aggregation program. The rules and regulations shall provide that the costs allowed to be recovered pursuant to this subsection shall be recovered on a timely basis from the governing body or government energy aggregator that is a municipality or a county, as the case may be. No electric public utility or gas public utility shall be required to seek recovery of costs for a government energy aggregation program or costs for assisting a governing body considering a government energy aggregation program from the electric public utility's or gas public utility's shareholders or ratepayers.

c. As used in this section "government aggregator," " government energy aggregation program," "electric power supplier" and "gas supplier" shall have the same meaning as set forth in section 3 of P.L.1999, c. 23 (C.48:3-51).

N.J. Rev. Stat. § 48:3-93.3. Contract negotiations; campaign contributions; violations

a. The provisions of any law, or rule or regulation adopted pursuant thereto, to the contrary notwithstanding, a government aggregator that is a municipality or a county shall not award a contract to a licensed electric power supplier, a licensed gas supplier, or appliance repair service provider if the licensed electric power supplier, licensed gas supplier, or appliance repair service provider has solicited or made any contribution of money, or pledge of contribution, including in-kind contributions, to a campaign committee of any candidate or holder of the public office having ultimate responsibility for the award of the contract, or to any State, county or municipal party committee or legislative leadership committee, in excess of the thresholds specified in subsection c. of this section within one calendar year immediately proceeding commencement of negotiations for the contract.

b. No licensed electric power supplier, licensed gas supplier, or appliance repair service provider which enters into negotiations for, or agrees to, any contract with a government aggregator that is a municipality or a county shall knowingly solicit or make any contribution of money, or pledge of a contribution, including in-kind contributions, to any candidate or holder of the public office having ultimate responsibility for the award of the contract, or to any State, county or municipal party committee or legislative leadership committee, between the commencement of negotiations for and the later of the termination of negotiations or the completion of the contract.

c. Any individual included within the definition of a licensed electric power supplier, licensed gas supplier, or appliance repair service provider pursuant to subsection o. of this section may annually contribute a maximum of $250 for any purpose to any candidate for the office of Governor or for the office of member of the Legislature, or $500 to any State, county or municipal party committee or legislative leadership committee, without violating subsection a. of this section. However, any group of individuals meeting the definition of a licensed electric power supplier, a licensed gas supplier, or appliance repair service provider pursuant to subsection o. of this section, in the aggregate shall not annually contribute for any purpose in excess of $5,000 to all candidates for the office of Governor or for the office of member of the Legislature and officeholders with ultimate responsibility for the awarding of the contract, and all State, county and municipal political parties and legislative leadership committees combined, without violating subsection a. of this section.

d. For purposes of this section, the office that is considered to have ultimate responsibility for the award of the contract shall be any elected official of the governing body of the municipality or county serving as the government aggregator.

e. No contribution of money or other thing of value, including in-kind contributions, made by a licensed electric power supplier, a licensed gas supplier, or appliance repair service provider to any candidate for the office of Governor or for the office of member of the Legislature or State, county or municipal party committee or legislative leadership committee shall be deemed a violation of section a. of this section nor shall an agreement for property, goods or services, of any kind whatsoever, be disqualified thereby, if that contribution was made by the licensed electric power supplier, licensed gas supplier, or appliance repair service provider prior to the effective date of P.L.2003 c. 24 (C.48:3-93.1 et al).

f. (1) Prior to awarding any contract to a licensed electric power supplier, a licensed gas supplier, or appliance repair service provider, a government aggregator that is a municipality or a county shall receive a sworn statement from the licensed electric power supplier, licensed gas supplier, or appliance repair service provider made under penalty of perjury that the licensed electric power supplier, licensed gas supplier, or appliance repair service provider has not made a contribution in violation of subsection a. of this section.

(2) A licensed electric power supplier, licensed gas supplier, and appliance repair service provider shall have a continuing duty to report any violations of this section that may occur during the negotiation of duration of the contract.

g. Candidates for the office of Governor or for the office of member of the Legislature, and State and county party committees and legislative leadership committees shall use reasonable efforts to notify contributors and potential contributors that contributions, including in-kind contributions, from a licensed electric power supplier, a licensed gas supplier, or appliance repair service provider and certain individuals associated with a licensed electric power supplier, licensed gas supplier, or appliance repair service provider may affect the ability of the licensed electric power supplier, licensed gas supplier, or appliance repair service provider to contract or continue to contract with a government aggregator that is a municipality or a county. Such reasonable efforts shall include, but need not be limited to, notification in written fundraising solicitations or donor information request forms or other fundraising solicitation materials. The failure of a licensed electric power supplier, licensed gas supplier, or appliance repair service provider to receive the notice prescribed in this subsection shall not be a defense to a violation of subsection a. of this section.

h. A licensed electric power supplier, licensed gas supplier, appliance repair service provider, candidate for the office of Governor or for the office of member of the Legislature, an officeholder or a State, county or municipal party committee or legislative leadership committee may cure a violation of subsection a. of this section if, within 30 days after the election for which a contribution is made the licensed electric power supplier, licensed gas supplier, or appliance repair service provider seeks and receives reimbursement of a contribution from the candidate for the office of Governor or for the office of member of the Legislature or State, county or municipal political party or legislative leadership committee.

i. It shall be a breach of the terms of a contract for a licensed electric power supplier, licensed gas supplier, or appliance repair service provider to violate subsection a. of this section or to knowingly conceal or misrepresent contributions given or received, or to make or solicit contributions through intermediaries for the purpose of concealing or misrepresenting the source of the contribution, and any such licensed electric power supplier, licensed gas supplier, or appliance repair service provider shall be subject to penalties prescribed in subsection k. of this section and any other penalties prescribed by law.

j. No person shall make and no person, other than a candidate or an official representative of the candidate committee or joint candidates committee of the candidate, shall accept any contribution on the condition or with the agreement that it will be contributed to any other particular candidate, subject to penalties prescribed in subsection k. of this section and any other penalties prescribed by law. The expenditure of funds received by a person shall be made at the sole discretion of the recipient person.

k. Any licensed electric power supplier, licensed gas supplier, or appliance repair service provider who knowingly fails to reveal a contribution made in violation of subsection a. of this section, or who knowingly makes or solicits contributions through intermediaries for the purpose of concealing or misrepresenting the source of the contribution, shall be disqualified from eligibility for future energy aggregation program contracts for a period of four calendar years from the date of the determination of violation, and shall have any contract with the State then in effect immediately terminated.

l. The governing body of a county or municipality shall have the option to promulgate and implement its own ordinances restricting campaign contributions by licensed electric power suppliers and licensed gas suppliers.

m. (1) Any licensed electric power supplier, licensed gas supplier, or appliance repair service provider making a contribution to any candidate, committee, or political party shall file an annual disclosure statement with the New Jersey Election Law Enforcement Commission setting forth all political contributions made during the 12 months prior to the reporting deadline.

(2) The Election Law Enforcement Commission shall prescribe forms and procedures for the reporting required in paragraph (1) of this subsection which, at a minimum, shall require the following information:

(a) The names and addresses of the licensed electric power supplier, licensed gas supplier, or appliance repair service provider making the contributions, and the amount contributed;

(b) The name of the candidate committee or political party receiving the contribution; and

(c) The amount of money received from a government aggregator that is a municipality or a county.

n. The Election Law Enforcement Commission shall maintain a list of such reports for public inspection both at the commission's office and through the commission's electronic disclosure Web site.

o. (1) For purposes of this section, "electric power supplier" and "gas supplier" shall have the same meaning as set forth in section 3 of P.L.1999, c. 23 (C.48:3-51), and shall include all principals who own 10 percent or more of the equity in an entity that is an electric power supplier or a gas supplier, partners, and all officers in the aggregate employed by the entity, as well as any subsidiaries directly controlled by the entity. "Appliance repair service provider" means any person or entity engaged in the maintenance, repair or replacement of appliances and providing such services as part of a government energy aggregation program pursuant to P.L.1999, c. 23, and shall include all principals who own 10 percent or more of the equity in an entity which is an appliance repair service provider, partners, and all officers in the aggregate employed by the entity, as well as any subsidiaries directly controlled by the entity. "Contract" shall mean a contract between a government aggregator that is a municipality or a county for a government energy aggregation program entered into pursuant to the provisions of section 2 of P.L.2003, c. 24 (C.48:3-93.2) or the provisions of P.L.1999, c. 23.

(2) For the purposes of this section, "contribution," "in-kind contribution," "other thing of value," "candidate," "candidate committee," "joint candidates committee," "legislative leadership committee," "State, county or municipal political party" and "State, county or municipal party committee" shall have the meanings set forth in the "New Jersey Campaign Contributions and Expenditures Reporting Act," P.L.1973, c. 83 (C.19:44A-1 et seq.).

N.J. Rev. Stat. § 48:3-94. Government aggregator as a municipality or county

a. (1) A government aggregator that is a municipality or a county may operate a government energy aggregation program that provides for the aggregation of residential electric generation service or gas supply service , non-residential electric generation service or gas supply service on a voluntary basis, and appliance repair services for residential and non-residential customers on a voluntary basis, either separately or bundled, in accordance with the provisions of this section.

(2) Electric generation service or gas supply service for residential customers within the municipality or county and for non-residential customers on a voluntary basis,and for appliance repair services for residential and non-residential customers on a voluntary basis, may be aggregated together with electric generation service, electric related service, gas supply service or gas related service, either separately or bundled, for the government aggregator's own facilities or with other government aggregators, provided that each governing body adopts an ordinance in the case of a municipality, or resolution in the case of a county, after notice and public hearing, indicating its intent to solicit bids for the provision of electric generation service or gas supply service, either separately or bundled , and for appliance repair services on a voluntary basis at a separate price and by separate bid solicitation, as the case may be, which approval shall require passage by a majority vote of the full membership of the governing body

(3) If an ordinance or resolution adopted pursuant to paragraph (2) of this subsection would include non-residential customers in a government energy aggregation program on a voluntary basis, the adoption of the ordinance or resolution shall be accompanied by a public notice that non-residential customers will be included in the government energy aggregation program if they contact the appropriate governing body within 30 days of the adoption of the ordinance or resolution stating their affirmative choice to be included in the government energy aggregation program.

(4) (a) If an ordinance or resolution adopted pursuant to paragraph (2) of this subsection would include appliance repair services for residential or non-residential customers on a voluntary basis at a separate price and by separate bid solicitation, the adoption of the ordinance or resolution shall be accompanied by a public notice that residential or non-residential customers may receive appliance repair services if they contact the appropriate governing body within 30 days of the adoption of the ordinance or resolution stating their affirmative choice to receive appliance repair services under the government energy aggregation program.

(b) The Board of Public Utilities shall adopt, pursuant to the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.), rules and regulations determining the manner in which electric related services and gas related services, other than appliance repair services, shall be included in government energy aggregation programs.

(5) A government energy aggregation program shall be structured to provide that each residential or non residential customer, as the case may be, shall receive electric generation service or gas supply service from one licensed electric power supplier or one licensed gas supplier, as the case may be.

(6) Any residential or non-residential customer receiving electric generation service or gas supply service from a licensed electric power supplier or a licensed gas supplier prior to the establishment of a government energy aggregation program pursuant to this section shall be exempt from a government energy aggregation program established pursuant to this section. Under no circumstance shall a residential or non-residential customer's

affirmative choice to be included in a government energy aggregation program abrogate the existing terms of an electric power or gas supply contract between a non-residential customer and a licensed electric power supplier or licensed gas supplier.

b. (1) The governing body shall commence public bidding pursuant to the provisions of the "Local Public Contracts Law," P.L.1971, c. 198 (C.40A: 11-1 et seq.) to receive bids from a licensed electric power supplier or licensed gas supplier, as appropriate, for electric generation service or gas supply service at one or more projected load levels, either separately or bundled, for customers within the municipality or county, and if appropriate, for any appliance repair services at a separate price and by separate bid solicitation, and for electric generation service, electric related service, gas supply service or gas related service, either separately or bundled, for the government aggregator's own facilities. Thirty days prior to the commencement of public bidding the governing body shall transmit the bid notice and all bidding documents to the board and the Division of the Ratepayer Advocate for review. The board and the Division of the Ratepayer Advocate shall have 15 days to review the bid notice and bidding documents and provide comments to the governing body, which may accept or reject the comments.

(2) Upon receipt of the bids, the governing body shall evaluate the proposals. The governing body shall select a licensed electric power supplier or licensed gas supplier, or both, based on the most advantageous proposal, price and other factors considered. The governing body shall only select a licensed electric power supplier or licensed gas supplier to be awarded a contract for service where the rate is the same as or lower than the price of basic generation service pursuant to section 9 of P.L.1999, c. 23 (C.48:3-57) plus the pro-rata value of the cost of compliance with the renewable energy portfolio standards imposed pursuant to this act derived from a non-utility generation contract with an electric public utility and transferred by the electric public utility to a supplier of basic generation service or basic gas supply service pursuant to section 10 of P.L.1999, c. 23 (C.48:3-58), as determined by the board. The governing body may award a contract for electric generation service where the rate is higher than the price of basic generation service as determined by the board pursuant to section 9 of P.L.1999, c. 23 plus the pro- rata value of the cost of compliance with the renewable energy portfolio standards imposed pursuant to this act derived from a non-utility generation contract with an electric public utility and transferred by the electric public utility to a supplier of basic generation service, provided that the award is for electricity the percentage of which that is derived from verifiable Class I or Class II renewable energy as defined pursuant to section 3 of P.L.1999, c. 23 (C.48:3-51) is greater than the percentage of Class I and Class II renewable energy required pursuant to subsection d. of section 38 of P.L.1999, c. 23 (C.48:3-87), and that the customers are informed, in a manner determined by the board secretary, that such a higher rate is under consideration by the governing body.

c. Upon selection of a licensed electric power supplier or licensed gas supplier, or both, pursuant to subsection b. of this section, the governing body shall enter into a written agreement with the selected licensed supplier. The written agreement shall include:

(1) the contract with the selected licensed electric power supplier or licensed gas supplier, or both, for the government aggregator's own load; and

(2) a contract form which shall comply with and include the requirements of subsection a. of section 43 of P.L.1999, c. 23 (C.48:3-92).

The governing body shall transmit a copy of the written agreement to the board and the Division of the Ratepayer Advocate, each of which shall have 15 days to review the written agreement and provide comments to the governing body, which may accept or reject the comments.

d. (Deleted by amendment, P.L.2003 c. 24)

e. (1) After entering into the agreement pursuant to section c. of this section, the governing body shall provide written individual notice to customers advising them of their individual right to affirmatively decline participation in the government energy aggregation program, and providing 30 days for customers to respond to the governing body of their decision to affirmatively decline participation in the government energy aggregation program and providing them with the price and other factors allowing the customer to compare the government energy aggregation program to other alternatives; and

(2) upon expiration of the 30-day period required pursuant to paragraph (1) of this subsection, the governing body shall determine the number and identity of customers who did not affirmatively decline to participate in the government energy aggregation program.

(3) The governing body shall then authorize the selected licensed electric power supplier or licensed gas supplier, or both, to enroll eachcustomer within the municipality or county who did not initially affirmatively decline to be part of a government energy aggregation program pursuant to the provisions of paragraph (1) of subsection e. of this section.

(4) The Board of Public Utilities shall adopt, pursuant to the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.), rules and regulations regarding service for residential and non-residential customers in municipalities and counties in which government energy aggregation programs have been established providing for the notification to new customers of the availability of the established government energy aggregation program and their option to enroll in the program, and establishing a process by which customers that have been enrolled in a government energy aggregation program and that move to a new location where that same government energy aggregation program is available may consent to continue in the program without reverting to basic generation service or basic gas service. The rules and regulations adopted by the board pursuant to this section shall provide for the recovery by an electric public utility or a gas public utility of all reasonable costs incurred by the electric public utility or gas public utility in complying with the regulations adopted pursuant to this section.

f. The licensed electric power supplier or licensed gas supplier, or both, selected pursuant to the provisions of this section shall be subject to the provisions of section 37 of this act.

g. Whenever the process results in a change of provider of energy or of price to program participants, the governing body shall give residential customers notice, as determined by the board, of their right to decline continued participation.

h. A government aggregator that is a county may implement the provisions of this section only as authorized pursuant to the provisions of subsection f. of section 43 of this act.

i. The provisions of this section shall only apply to government energy aggregation programs for residential customers and to non-residential customers on a voluntary basis.

j. Nothing in this section shall preclude a government energy aggregation program from including non- residential customers as participants on a voluntary basis and in a clear and consistent manner.

k. Nothing in this section shall preclude a residential customer who did not affirmatively decline to participate in a government energy aggregation program from switching electric service to another electric power supplier or to basic generation service pursuant to regulations adopted by the board.

N.J. Rev. Stat. § 48:3-95. Interim rules and regulations

Notwithstanding the provisions of the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.) to the contrary, the board shall initiate a proceeding and shall adopt, after notice, provision of the opportunity for comment, and public hearing, such interim rules and regulations as the board determines to be necessary to effectuate the provisions of this act within 90 days of the effective date of this act. Such standards shall be effective as regulations immediately upon filing with the Office of Administrative Law and shall be effective for a period not to exceed 18 months, and may, thereafter, be amended, adopted or readopted by the board in accordance with the provisions of the "Administrative Procedure Act."

N.J. Rev. Stat. § 48:3-96. Standards for inspection, maintenance, repair and replacement of distribution equipment

a. The Board of Public Utilities shall adopt, pursuant to the "Administrative Procedure Act," P.L.1968, c. 410 (C.52:14B-1 et seq.), standards for the inspection, maintenance, repair and replacement of the distribution equipment and facilities of electric public utilities. The standards may be prescriptive standards, performance standards, or both, and shall provide for high quality, safe and reliable service. The board shall also adopt standards for the operation, reliability and safety of such equipment and facilities during periods of emergency or disaster. The board shall adopt a schedule of penalties for violations of these standards.

b. In adopting standards pursuant to this section, the board shall consider cost, local geography and weather, applicable industry codes, national electric industry practices, sound engineering judgment, and past experience.

c. The board shall require each electric public utility to report annually on its compliance with the standards adopted pursuant to this section, and the utility shall make these reports available to the public.

N.J. Rev. Stat. § 48:3-97. Construction of act

a. No provision of this act shall be interpreted or construed in any fashion so as to amend or alter the functions, powers and duties of the Commissioner of Transportation in respect to autobuses, charter and special bus operations, railroads, street railways, traction railways, and subways as transferred to the commissioner by Executive Reorganization filed on October 5, 1978, pursuant to the provisions of the "State Agency Transfer Act," P.L.1971, c. 375 (C.52:14D-1 et seq.).

b. No provision of this act shall be interpreted or construed in any fashion so as to amend or alter the functions, powers and duties of the Commissioner of Environmental Protection in respect to the commissioner's role in protecting the environment.

N.J. Rev. Stat. § 48:3-98. Effective date

This act shall take effect immediately, except that, to the extent not already provided for by existing law, the authority of the board to order rate unbundling filings, restructuring filings, and stranded cost filings, perform audits of utility competitive services and take such other regulatory actions, including, but not limited to, the holding of hearings, providing of notice and opportunity for comment, the issuance of orders, and the establishment of standards, including auction standards adopted for application to an electric public utility that is executing a divestiture plan, and to take such other anticipatory regulatory action as it deems necessary to fulfill the purposes or requirements of this act shall apply retroactively to April 1, 1997 provided that the board shall take such actions as may be necessary, if any, to ensure that the requirements of this act are met in all regulatory actions related to this act which were commenced prior to its enactment.

Tab D

Or. Rev. Stat. § 757.072 Agreements for financial assistance to organizations representing customer interests; rules.

(1) A public utility providing electricity or natural gas may enter into a written agreement with an organization that represents broad customer interests in regulatory proceedings conducted by the Public Utility Commission relating to public utilities that provide electricity or natural gas. The agreement shall govern the manner in which financial assistance may be provided to the organization. The agreement may provide for financial assistance to other organizations found by the commission to be qualified under subsection (2) of this section. More than one public utility or organization may join in a single agreement. Any agreement entered into under this section must be approved by the commission before any financial assistance is provided under the agreement.

(2) Financial assistance under an agreement entered into under this section may be provided only to organizations that represent broad customer interests in regulatory proceedings before the commission relating to public utilities that provide electricity or natural gas. The commission by rule shall establish such qualifications as the commission deems appropriate for determining which organizations are eligible for financial assistance under an agreement entered into under this section.

(3) In administering an agreement entered into under this section, the commission by rule or order may determine:

(a) The amount of financial assistance that may be provided to any organization;

(b) The manner in which the financial assistance will be distributed;

(c) The manner in which the financial assistance will be recovered in the rates of the public utility under subsection (4) of this section; and

(d) Other matters necessary to administer the agreement.

(4) The commission shall allow a public utility that provides financial assistance under this section to recover the amounts so provided in rates. The commission shall allow a public utility to defer inclusion of those amounts in rates as provided in ORS 757.259 if the public utility so elects. An agreement under this section may not provide for payment of any amounts to the commission.

Tab E

LEXSEE 2003 N.Y. PUC LEXIS 475

Minor Rate Filing of Chazy & Westport Telephone Corporation for Approval to Increase Local Rates by $ 300,000 Annually

CASE 02-C-1294

New York Public Service Commission

2003 N.Y. PUC LEXIS 475

August 27, 2003, Issued and Effective

CORE TERMS: non-regulated, regulated, royalty, staff, intrastate, telephone, historic, accounting, customer, salary, subsidiary, deferral, line of credit, depreciation, payroll, pension, calculation, rate case, competitive, settlement, marketing, ratepayer, operating expenses, capitalization, affiliate, allocate, rate base, lump sum, annual, reduction

DISPOSITION: [*1] ORDER DENYING RATE INCREASE

PANEL: COMMISSIONERS PRESENT: William M. Flynn, Chairman; Thomas J. Dunleavy; James D. Bennett; Leonard A. Weiss; Neal N. Galvin

OPINION: At a session of the Public Service Commission held in the City of Albany on July 23, 2003

BY THE COMMISSION:

INTRODUCTION

On October 3, 2002, Chazy & Westport Telephone Corporation (Chazy & Westport or the company) filed the tariff revisions listed in Appendix A to increase its local service rates effective March 1, 2003. n1 The company indicated that it had a revenue deficiency of approximately $ 380,000. However, in order to comply with the Commission's mini rate case filing guidelines, the company limited its requested increase in local service revenues to $ 300,000. n2 The proposal would have increased basic residential rates by 77% in the two largest exchanges, and by 53% in the other exchange. Business rates would have increased by 85% and 54%, respectively. Increases to the return check charge, Central Office line charge, line change charge, premise visit charge and locality charge were also proposed.

n1 The company subsequently postponed this date to June 1, 2003 and then to August 1, 2003, to allow sufficient time for review. [*2]

n2 Public Service Law, Section 92(c).

Our review of the filing resulted in numerous adjustments, which yield a total revenue decrease of $ 127,419 (18.3%). The adjustments are discussed in detail below and the calculation of the revenue requirement is shown in Appendix B. A short form order denying the rate increase was issued on July 25, 2003. n3 The company's rates will not be reduced at this time, but a deferral will be established to preserve this potential reduction in rates. Because the company may file for a rate increase when the New York Intrastate Access Settlement Pool Proceeding (Case 02-C-0595 or the Access Pool Proceeding) n4 is resolved, we encourage the company to work with staff to utilize the moneys available as a result of this case to mitigate possible future rate increases.

44,000 of one-time upgrades and back billing of computer charges in the historic test year are not likely to reoccur. Our adjustment to remove these one-time items from the company's historic test year reduces the company's expenses by $ 86,724 (Intrastate - $ 58,377; Adjustment 10 in Appendix B, Schedule 4).

Executive Expenses

Review of a number of executive-related vouchers associated with the historic test year revealed approximately $ 41,300 related to non-documented and/or personal expenses (Intrastate - $ 28,316; Adjustment 11 in Appendix B, Schedule 4). These expenses must be removed from the rate year, because they are unrelated to the operations of the telephone company. Even with this adjustment, the level of the company's executive expenses is high and could be reduced further. [*36] Indeed, the company has indicated that it plans to target a 25% reduction related to executive travel and meal expenses.

Depreciation

On December 29, 2000, Chazy & Westport filed a letter with the Commission revising its depreciation rates effective January 1, 2000. The effect of the changes increased annual depreciation expense by approximately $ 35,000, further increasing the excess in the company's depreciation book reserve. Review of the company's study raised concerns regarding some of the service lives chosen and their impact on the booked depreciation reserve. Based on the company's study, in a letter dated January 22, 2001, staff recommended that the annual depreciation rates should remain unchanged. Notwithstanding this recommendation, the company booked the higher depreciation expense.

We reduced the annual depreciation expense by $ 60,632 (total company), or $ 40,314 (intrastate), to reflect the use of staff's annual depreciation accrual rates, as determined from its depreciation reserve requirement study as of June 30, 2002. The depreciation expense was further reduced by $ 114,556 (total company), or $ 76,168 (intrastate), to reflect amortizing the excess in the company's [*37] booked depreciation reserve. The amortization period is determined by taking the lesser of the composite remaining life of all depreciable plant or ten years. Because staff's study indicates a composite remaining life of 11.24 years, a 10-year amortization has been utilized. While we normally would have used a 5-year amortization, a 10-year period addresses potentially significant rate impacts due to the likely phase-out of the Access Pool, from which Chazy & Westport is a major recipient.

The company does not agree with the depreciation adjustments and made three counter proposals. First, the company proposed retiring remote switching equipment associated with the Chazy central office at the same retirement date as the Chazy host office. This proposal is not acceptable because the Chazy office, with an age of 20 years, is nearing its estimated retirement date of 2006, while the remote switching equipment has retirement dates ranging from 2013-2021. Assigning the remote switching equipment the same retirement date would unduly accelerate the depreciation of this equipment.

The company did not respond to a request to provide an estimated retirement date for the Chazy office. Therefore, [*38] in its depreciation reserve requirement study, staff used an estimated retirement date of 2006. In subsequent discussions with the company, staff concluded that the Chazy host central office would probably not be retired until the year 2010. However, use of a 2010 retirement date would result in a smaller annual depreciation expense and thus a larger adjustment than has been made.

The second company proposal concerned a claim that its present policy for booking salvage is incorrect, and it proposed an adjustment to correct it. Our review found that the company is properly booking salvage and no further adjustment is necessary. Chazy & Westport's percent net salvage is consistent with other similarly-sized independent telephone companies in New York State.

Lastly, the company proposed to amortize the excess in the company's book reserve over the composite remaining life of the plant. While this method is used in some cases, as discussed above, the 10-year period is appropriate in this instance. The total amount of this adjustment is $ 175,188 (Intrastate - $ 116,482; Adjustment 12 in Appendix B, Schedule 4).

Rate Base

There were several adjustments made to the company's rate [*39] base. These adjustments are either discussed throughout this memorandum or track expense adjustments.

Rate of Return

Chazy & Westport provided an average historic test year capitalization for the year ended June 30, 2002. This capitalization reflected the regulated portion of the company and was used as a basis to arrive at the company's rate of return calculation. The company has a high amount of equity constituting 75.9% of its capitalization. Chazy & Westport used an 8.94% equity return based on the rate set in Attachment B from the Financial Relief Process Joint Report in Case 02-C-0595, dated September 3, 2002.

This return on equity was updated for interest rate conditions. At this time, the allowed return on equity would be 8.01%. This result was found to be consistent with a proxy 8.01%. This result was found to be consistent with a proxy group of telecommunications companies that provide local service and recent Commission decisions.

We adjusted the company's capital structure for one factor. Chazy & Westport did not include Unamortized Debt Expense and related amortization in its capital structure and cost of debt, respectively. This adjustment increases the company's [*40] weighted cost of debt from 1.23% to 1.25%.

The resulting overall rate of return for Chazy & Westport is 7.38%. The company's capital structure and cost rates are as follows:

Capitalization Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 7,917.010	75.87%	8.01%	6.07%
preferred Stock	130,000	1.25%	5.00%	0.06
Customer Deposits	4,084	.04%	3.85%	0.00%
Notes Payable	326,627	3.13%	4.69%	0.15%
Long Term Debt	2,056,306	19.71%	5.56%	1.10%
Total	$ 10,434,027	100.00%		7.38%

Other Issues

Line of Credit

A review of Chazy & Westport stockholder's annual report for June 30, 2002, found that the company's non-regulated subsidiary, Westelcom, has an unsecured line of credit with a bank for $ 2 million. The balance of this line of credit was $ 1,280,000 as of June 30, 2002. Chazy & Westport guaranteed the full line of credit. If Westelcom defaults, Chazy & Westport is responsible for satisfying the terms of the line of credit. Because this places a potential liability on the telephone company and represents an investment in its non-regulated subsidiary for which no approval was sought, the company is in violation of Sections 101 and 107 of the Public [*41] Service Law.

The company has been advised of our concerns, and it has agreed that Westelcom would make no additional drawdown of the line of credit. The company also agreed to re-negotiate the line of credit so that Chazy & Westport no longer is the guarantor. The company will be directed to file the final line of credit documents with the Director of the Office of Accounting and Finance confirming the removal of such guaranty.

Pension Distribution and Termination

Two major shareholders, who were employees of Chazy & Westport, elected to take lump sum payments from the company's pension plan in 1999. These payments totaled almost $ 2 million, representing approximately 70% of the company's pension plan assets before the lump sum payments. After the payments were made, the overfunding in the pension plan was reduced from $ 707,000 to $ 273,000. In addition, the company terminated its traditional defined benefit pension plan in 2000 and converted it into a defined contribution plan (e.g., 401k). These actions raise at least two concerns. First, both of these events required, at a minimum, Commission notification pursuant to the Commission's Policy Statement on Pensions and Post-Retirement [*42] Benefits (e.g., retiree health insurance). Second, because the excess funds in the pension plan were substantially reduced subsequent to the lump sum distributions, it is possible that the lump sum payments awarded to the employees were greater than the benefits that were earned as of the distribution date. (This would suggest an improper use of ratepayer provided capital.)

Chazy & Westport claims that the issue rests with its actuary, who purportedly calculated the lump sum distributions according to the plan provisions. n18 The company's position does not address our concerns. It is the company's responsibility to ensure that it follows the Commission's Policy Statement on Pensions and OPEBs. The Commission's Policy Statement is clear that notification is required in the case of settlements or terminations. Moreover, because pension fund assets have been funded with ratepayer provided money and the company's pension funds exceed its liabilities, pension fund gains must be preserved for ratepayers benefit.

Tab F

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-07-02 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND ITS RATE SCHEDULES

December 17, 2003

By the following Commissioners:

Donald W. Downes
Jack R. Goldberg
John W. Betkoski, III
Linda J. Kelly
Anne C. George

DECISION

TABLE OF CONTENTS

I. INTRODUCTION 1

A. Summary 1

B. Background of the Proceeding 2

C. Conduct of the proceeding 3

D. Parties and Intervenors 3

E. Public Comment 3

II. COMPANY PROPOSAL AND DEPARTMENT ANALYSIS 5

A. Rate Plan 5
1. Office of Consumer Counsel 6
2. Office of Attorney General 7
3. Prosecutorial 7
4. Rate Plan Analysis 8

B. Test Year/Rate Year 9

C. Reliability and Distribution Infrastructure Plan 9
1. Reliability 9
2. Construction Program 12
a. Bare Wire Replacement 19
b. Facilities 19
c. Streetlight Capital Improvement Program 20
d. Conclusion on Capital Program 21
3. Demand Side Management 23
4. Underground Facilities 24
5. Northwest Connecticut 25

D. Rate Base 26
1. Plant in Service 26
2. Retirements 27
3. Reserve for Depreciation 28
4. Accumulated Provision for Deferred Income Taxes 28
5. Materials and Supplies 29
6. Deferred Assets 30
a. Company Proposal 30
b. OCC and AG Positions 31
c. Incremental Sabotage & Terrorism Insurance 31
d. Incremental Security Costs 32
e. Unrecognized Pension Gain 32
f. Code of Conduct Compliance 32
g. Incremental State Income Tax 33
h. NRG Station Service Receivable 33
i. Deferred Legal Costs 34
j. Summary 35
7. GSC Overrecoveries 36
8. Storm Reserve 37
9. Working Capital 37

a. Summary 37
b. Position of the Company 38
c. Position of OCC 38
d. Department Analysis 39
e. Conclusion on Working Capital 45
10. Rate Base impacts of Pensions/OPEB/401K 46
11. Summary of Rate Base 46

E. Expenses **47**
1. Computer Expense 47
2. Insurance Expense 48
a. Directors and Officers Liability Insurance 48
b. Public Liability Expense 49
c. Insurance Expense Summary 50
3. Outside Services 50
a. Escalation Rates 50
b. Audit Expenses 50
c. Training 51
4. Regulatory Assessments 51
5. Facility Rent Expense 51
6. Vehicle Leases & Registration 54
7. Payroll Expense 54
a. Payroll Proposals 54
b. Attrition Management Plan 55
c. NUSCO Personnel Capitalization 57
d. Other Initiatives 57
e. Fringe Benefits 57
f. Salary and Fringe Benefit Summary 58
8. MIBS Amortization Expense 58
9. Depreciation Expense 58
a. Distribution Account 362 – Station Equipment 59
b. Dist. Accts. 364, Poles, Towers and Conductors, and 365, Overhead Conductors and Devices 59
c. Depreciation Expense Changes 60
d. Accumulated Depreciation Changes 62
e. ADIT Changes 63
10. Taxes 65
a. Property Taxes 65
b. Payroll Taxes 66
c. CCBT, GET, Uncollectibles and Gross Revenue Conversion Factor 67
d. State Income Tax Credit 69
11. Hydro Quebec 69
12. Storm Reserve Accrual 70
13. Regulatory Asset Amortization 71
14. Regulatory Liability Amortization 71
15. Relocation Expense 71
16. Economic Development Funding 72
17. Corporate Aircraft 73
18. Materials and Supplies 74
19. Residual O&M 75
20. Inflation 75
21. Telecommunication Expense 76
22. Pension/Other Post Retirement Employee Benefit (OPEB) Expense 76
a. Summary 76
b. Pensions 77
c. OPEB 77
d. Capitalization 77
e. Actuarial Assumptions 78
f. Calculation of Expenses 79

g. Pension Deferral Mechanism 83
23. Unrecognized Pension Gain 85
24. Supplemental Retirement Plan (401K) Expense 86
25. Non-SERP Expense 86
26. Incentive Compensation 87
27. Initiative Expenses 88
28. Group Relamping Expense 93
29. Interest Synchronization 93
30. Summary of Expense Adjustments 94

F. Revenues 95
1. Test Year and Rate Year Revenues 95
2. Sales and Revenue Forecast 95
3. Price Elasticity 102
4. Other Revenue - Forfeited Discounts 104
5. Revenue Protection 105

G. Rates and Rate Design 106
1. Distribution Rates 106
a. Controlled Water Heaters 106
b. Residential Time of Use Rates 108
c. KVA Metering 111
d. Streetlight Rates 115
e. Streetlight Plant Values 120
f. Streetlight Billing Procedures 122
g. Interruptible Rates 123
2. Transmission Revenue Requirement 124

H. Cost of Capital/Capital Structure 126
1. Introduction 126
2. Capital Structure 127
3. Cost of Long-Term Debt 127
4. Cost of Preferred Stock 129
5. Cost of Equity 129
a. Introduction 130
b. Company ROE Proposal 130
c. Position of Parties 133
d. Cost of Equity Analysis 136
e. Conclusion on Cost of Equity 145
6. Weighted Cost of Capital 146

I. Earnings Sharing Mechanism 147

J. Prepaid Pension Asset 148

K. Customer Service Issues 150
1. Standard Bill Form & Customer Deposit Requirements 150
2. Telephone Answering Responsiveness 151
3. Revenue Protection 152
4. Estimated Bills and Standard Market Design 156
5. Customer Surveys 156
6. Spanish speaking customers' access to services and information 157
7. Late Payment Charge (LPC) 157
8. Logging medical certificates 158
9. Service Quality Plan (SQP) 158
10. Rate Discount 159
11. Arrearage Forgiveness Plan 159

L. Station Service 159

III. FINDINGS OF FACT 161

IV. CONCLUSION AND ORDERS 174

A. Conclusion 174

B. Orders 177

V. ATTACHMENTS

Attachment A – CL&P's proposed capital expenditures ($000)

Attachment B – CL&P's Proposed O&M Initiatives 2004 ($000)

VI. INDEXES

Index A, Income Statement – 2004

Index B, Rate Base - 2004

Index A, Income Statement -2005

Index B, Rate Base - 2005

Index A, Income Statement - 2006

Index B; Rate Base - 2006

Index A, Income Statement - 2007

Index B, Rate Base – 2007

CL&P has not presented any evidence to cause the Department to change its position on this issue. Therefore, the Company's proposal is denied. Further, the Department must provide CL&P with a reasonable opportunity to recover its FERC-approved transmission revenue requirement. The Department is not required to forecast any cost related to CL&P's transmission expense. Therefore, CL&P's proposal to establish transmission rates for 2005-2007 based on forecasted cost increases/decreases is denied. Regarding CIEC's "flex down" proposal, distribution and transmission costs are distinct and the Company must be provided an opportunity to recover each of them. Therefore, it is inappropriate to adjust distribution rates to reflect changes in the FERC-approved transmission revenue requirement.

Based on the foregoing the Department will require CL&P to set its retail transmission rates based on a total revenue requirement of $111.7 million ($100.2+$14.5-$3). In addition the Department has adjusted CL&P's sales forecast for 2004. Therefore, CL&P must establish its retail transmission rates based on the revised forecast. CL&P will be required to submit final retail transmission rates for approval by the Department.

Based on the Department's allowed revenue requirement, $111.7 million, and the Department's revised sales for 2004, CL&P's transmission rate totals approximately $.00474, an increase of $.00120. This represents an increase of approximately 1.3% over CL&P's 2002 overall revenues. The Department denies CL&P's request to increase its Transmission Rate for 2005-2007 at this time. The Company may request rate relief should its FERC-approved transmission revenue requirements change.

H. Cost of Capital/Capital Structure

1. Introduction

The United States Supreme Court, in Federal Power Commission v. Hope Natural Gas Company, 320 US 591 (1944), established criteria to determine the cost of capital allowances. In its Decision, the Court determined that companies need to be allowed to earn a level of revenues sufficient to enable them to operate successfully, maintain their financial integrity and to attract capital and compensate their investors for their risk.

By Connecticut law, utilities are entitled to a level of revenues that will allow them ". . . to cover their operating and capital costs, to attract needed capital and to maintain their financial integrity, and yet provide appropriate protection for the relevant public interests, both existing and foreseeable." Conn. Gen. Stat. §16-19e(a)(4).

To calculate a rate of return on rate base that is appropriate for CL&P's overall cost of capital, the Department first identifies the components of the Company's capital structure. The cost of each capital component is then determined and weighted according to its proportion of total capitalization. These weighted costs are summed to determine the Company's overall cost of capital, which becomes the allowed rate of return on rate base (ROR).

2. Capital Structure

The Company proposed a weighted cost of capital of 8.76% and capital structure based on the average capitalization for the 2004 forecast year. The Company's ratemaking capital structure with proposed weighted cost of capital and associated cost for each class of capital are shown below:

Proposed 2004 Average Capitalization

Class of Capital	($000) Amount	% of Total	Cost	Weighted Cost
Long-Term Debt	743,899	43.38%	7.02%	3.05%
Preferred Stock	116,200	6.78%	5.09%	0.35%
Common Equity	854,691	49.84%	10.75%	5.36%
Total	1,714,790	100.00%		8.76%

Source: Schedule D-1.0

OCC's recommended cost of capital of 7.61% and capital structure, including suggested cost rates, is shown below. Rothschild PFT, pp. 11-15, and Schedule JAR 1.

Class of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	54.71%	7.16%	3.92%
Short-Term Debt	2.82%	1.88%	0.05%
Preferred Stock	7.54%	5.18%	0.39%
Common Equity	34.93%	9.30%	3.25%
	100.00%		7.61%

However, if the Company's proposed capital structure was used, OCC suggests using a lower cost of debt and lower cost of equity when computing the overall cost of capital. OCC recommended adjusting the cost rates of the Company's proposed capital structure, which results in a cost of capital of 7.74%, is shown below.

Class of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.38%	6.98%	3.03%
Short-Term Debt	0%	1.88%	0.00%
Preferred Stock	6.78%	5.09%	0.35%
Common Equity	49.84%	8.75%	4.36%
	100.00%		7.74%

Source: Rothschild PFT, Schedule JAR 1.

3. Cost of Long-Term Debt

The Company's average forecasted 2004 long-term embedded cost of debt is estimated at 7.02%. Schedule D-1.0. The 2004 long-term embedded cost of debt reflects the anticipated $2.608 million costs of amending CL&P's existing First Mortgage

Indenture to eliminate certain restrictive provisions, and three new ten-year secured debt issues. McHale PFT, p. 29. In addition, CL&P will incur issuance expenses that are amortized over the life of the bonds. CL&P's embedded cost of long-term debt is based on the use of an interest rate forecasting service.

OCC's witness, Mr. Rothchild recommended that CL&P's embedded cost of long-term debt be computed assuming that the new planned long-term debt issuances are accomplished at current interest rates. CL&P used an interest rate forecasting service for the $232 million of new debt projected to be issued in 2004. In response to interrogatory OCC-30, the Company stated that the total cost of new debt if issued today would be 5.47% instead of the 7.42% the company computed using a forecasted interest rate. If the capital structure requested by the Company were used, Mr. Rothschild suggested a lower embedded cost of debt of 6.98%, adjusting it for a more realistic estimate of the interest cost CL&P will have to pay on its new debt issuances. Rothschild PFT, p. 11. For applicability, Mr. Rothschild increased its recommended cost of debt by 0.18% (7.16%) to reflect the additional cost associated with the lower bond rating the Company had when it was using its prior capital structure. Rothschild PFT, p. 32.

In addition to the new debt issuances, unamortized debt expense increased by $2.608 million to reflect the costs of amending CL&P's existing First Mortgage Indenture (Mortgage). McHale PFT pp. 23-25. The recent sales of the Company's generating plants have effectively made CL&P's Mortgage unusable for the purpose of financing the substantial amounts of capital additions in the coming years. CL&P can no longer use property additions to either release property from the lien of the Mortgage or issue new bonds. CL&P is estimating a one-time cost of 100 basis points, or $2.608 million fee, paid to the Series B and Series D bondholders to eliminate the restrictive provisions of the Mortgage. There are three series of outstanding bonds under the lien of the Mortgage. The $2.608 million fee has been allocated to each of the three currently outstanding bond issues and is included in the Company's schedules for 2004. These costs are amortized over the remaining life of the underlying bonds. CL&P is seeking authority to recover the anticipated costs of amending its existing Mortgage by amortizing it over the remaining life of the three issues beginning January 1, 2004. The cost of the proposed change to the bond indenture has the effect of increasing the embedded cost of debt by .04%. Response to Interrogatory OCC-22.

The Department finds that based on CL&P's Order No. 1 compliance filing for the 12 months ended September 30, 2003, in Docket No. 76-03-07, Investigation to Consider Rate Adjustment Procedures and Mechanisms Appropriate to Charge or Reimburse the Consumer for Changes in the Cost of Fossil Fuel and/or Purchased Gas for Electric and Gas Public Service Companies, the Company shows that its embedded cost of debt was 6.74%. CL&P has testified that it is projected to be 7.02% for 2004. However, the Department believes that the current cost of new debt issuances should be lower than the actual embedded cost of debt of 6.74% as of September 30, 2003 and less Company's forecast of 7.02% using the current interest rates. Accordingly, the Department determines that 6.95% is a reasonable actual embedded cost of debt for CL&P. The 6.95% embedded cost of long-term debt shall reflect the current cost of new planned debt issuances and the cost of the proposed change to the bond indenture.

4. Cost of Preferred Stock

The Company is expected to have $116,200,000 in preferred stock in its capital structure at a cost of 5.09%. CL&P will not issue or retire preferred stock in 2004. Therefore, the preferred stock outstanding and dividends are unchanged from 2002. McHale PFT, p. 31. However, the 2004 cost of preferred stock includes the impact of the estimated $1.162 million cost to amend CL&P's Certificate of Incorporation. CL&P is seeking authority to amortize the estimated $1.162 million cost over ten years beginning on January 1, 2004.

CL&P's Certificate of Incorporation restricts the amount of unsecured debt having maturities of less than ten years to ten percent of total capitalization. CL&P currently has a temporary exemption from the ten percent test that expires in early 2004. McHale PFT, pp. 20-23. CL&P stated that if an extension was granted for another ten years it would not provide enough flexibility to issue enough unsecured debt to fund its infrastructure refurbishment program. Response to Interrogatory EL-193. Permanently eliminating these restrictions will provide CL&P more financial flexibility to lower financing costs and meet its funding needs. Beginning in January 1, 2004, unamortized issue expense is increased by $1.162 million to reflect the anticipated cost to solicit preferred stockholders to permanently eliminate the restrictive provision in CL&P's Certificate of Incorporation. In Schedule D-4, the $1.162 million fee has been allocated to each outstanding issue based on one percent of the outstanding balance of each issue. These costs are subsequently amortized over ten years. McHale PFT, p. 31. The cost of eliminating the restrictive provision in CL&P's Certificate of Incorporation has the effect of increasing the cost of preferred stock by .13% (5.09% - 4.96%). Response to Interrogatory OCC-18.

Also, on a rating agency basis, the Department notes that certain rating agencies and investment banking firms have changed their position and reduced the common equity credit assigned to CL&P's perpetual preferred stock. CL&P is now receiving approximately 50 percent common equity credit compared to the 100% in the prior rate case. The common equity credit assigned to CL&P's preferred stock reduces the amount of true common equity that the Company must maintain in order to achieve the same credit ratings objective. McHale PFT, pp. 18-19; Responses to Interrogatories EL-18 and OCC-15.

The Department accepts the Company's proposed 5.09% cost as submitted in Schedule D-4. The 5.09% reflects the cost of the proposed amendment to CL&P's Certificate of Incorporation.

5. Cost of Equity

Based on the testimony and evidence provided, it became indisputably clear that a change in CL&P's allowed return of 10.3%, established in 1998, was warranted in this proceeding. The Department found it necessary to make various adjustments to the cost of equity data submitted in order to improve its analytical quality. These adjustments, which were deemed reasonable, clearly supported a downward adjustment to the Company's return. In addition, CL&P has become a stronger company, financially, as evidenced through higher credit ratings and stronger capital structure. CL&P has reduced its operating risk by divesting itself of generation. The Company is clearly functioning in a lower interest environment, today, which has contributed to lower expected returns.

Therefore, in considering the arguments and analyses of the Parties and Intervenors, the Department has set CL&P's ROE at 9.85%, and adopts such return in this proceeding. The Department determines that such return is fair and reasonable, enabling the Company to operate properly and attract the necessary capital for expansion. The cost of equity component, which is a measure of the investor's expected return, is discussed as follows:

a. Introduction

There are several methods commonly used to determine the appropriate cost of equity. The determination of the cost of equity in this proceeding focused largely on the discounted cash flow (DCF) proxy group method. The DCF evaluates future cash inflows (dividends and capital gains) investors expect to receive from a stock against the current market price investors pay for the stock. The discount rate that brings the present value of the cash flows exactly equal to the market price is the cost of equity. The Department generally relies on the DCF analysis but also considers other methods. Accordingly, material was also presented using the risk premium capital asset pricing model (CAPM) by the OCC. The CAPM evaluates the cost of equity by determining first an appropriate risk free rate. To this rate it adds a beta (or the degree of co-movement of the security's rate of return with the market's rate of return) times the expected equity risk premium (the amount by which investors expect the future return on equities, in general, to exceed that on the riskless asset). The following is a summary of the positions of the parties and intervenors on the subject of cost of equity:

b. Company ROE Proposal

The Company's cost of equity testimony was prepared by George J. Eckenroth, Director of Financial Policy of NU. Based on Mr. Eckenroth's analysis, he advocated an allowed rate of return on equity (ROE) of 11.34%, including an additional upward adjustment to the ROE of 36 basis points for the flotation costs associated with the new equity. Mr. Eckenroth's testimony was primarily based on a discounted cash flow (DCF) analysis of ten comparable (proxy group) utilities. PFT, Eckenroth, p. 3. Using the DCF approach, Mr. Eckenroth performed two calculations: 1) analysts consensus estimates method (ACE) and 2) sustainable growth rate formula. In addition, as a check on the reasonableness of the recommended ROE, Mr. Eckenroth used a Risk Premium Model. Id. However, the Company proposed to utilize 10.75% ROE in computing its revenue requirements in this rate Application. The Company did not provide the calculations or analysis to support the proposed ROE of 10.75%. Also, it is unclear from the Company's testimony whether and to what extent the adjustment for flotation costs is included in the 10.75%.

First, Mr. Eckenroth employed the use of the ACE DCF method, which uses a simple average of the long-term earnings per share growth rates from Value Line, First Call and Zacks. Mr. Eckenroth's specific recommendation of 10.98%, excluding flotation costs of 36 basis points, was derived from the ACE DCF analysis. This method relied solely on earnings forecasts to define long-term growth expectations. Mr. Eckenroth stated that the use of growth forecasts published by investment services merits consideration, since investor growth expectations are a key input in the DCF model. Mr. Eckenroth argued that even if the forecasts are sometimes inaccurate, they shape the expectations of market participants and provide the best estimate of the growth projections that are built into stock prices. Response to Interrogatory EL-188.

As CL&P's stock is not publicly traded, Mr. Eckenroth's DCF calculations were based on a proxy group of ten publicly traded companies. These ten proxy group companies were chosen based on the selection criteria and review by Morgan Stanley & Co., Incorporated. The proxy group originally started with an initial pool of 63 electric utility companies that comprise the U.S. Utility Universe. Interrogatory EL-24, Bulk. Companies were eliminated from this group based on the following criteria: 1) non-utility revenues or earnings are more than 20% of total revenues or earnings, 2) a company's debt was below investment grade, 3) the company was a publicly known target of possible takeover or involved in mergers, 4) dividend cut since January 1, 2002 or dividend instability going forward, and 5) significant unregulated generation exposure. Eckenroth PFT, pp. 6-7. These companies with their stock ticker symbols were Central Vermont Public Service Corp. (CV), Consolidated Edison (ED), Empire District Electric (EDE), Energy East (EAS), Green Mountain Power (GMP), MGE Energy (MGEE), NSTAR (NST), SCANA (SCG), Southern Company (SO), and Wisconsin Electric (WEC). An ROE was calculated for each of those companies selected for the proxy group and an average of the proxy group was applied as an appropriate ROE for CL&P.

After selecting the ten-member proxy group, an ROE was calculated using the DCF method. The standard DCF formula assumes that the return received by investors is the sum of the future flow of dividends plus the anticipated growth in the selling price of the stock, discounted to the present. In other words, the current stock price is the summation of investors' assumed future flow of expected dividends discounted to the present. Assuming that the stock price increases consistently with dividend growth, this cash flow of dividends and future selling price equates to the future flow of dividends, and the DCF model takes the general form:

$$K = (D_0 \times (1 + g))/P_0 + g$$

where:
K = Investors' required return or equity cost of capital
D_0 = Actual dividends in the last 4 quarters
g = Estimated annual earnings growth rate
P_0 = Current stock price

The details underlying the ACE DCF cost of equity of 10.98% included: an average dividend yield of 4.74% for the proxy group; projected earnings per share growth rates based on equity analyst consensus long-term earnings growth published by Value Line, First Call and Zacks that averaged 5.97%; and a growth-adjusted dividend yield modified upward by one year's expected growth of 5.01%. The growth adjusted dividend yield was then added to the average earnings growth rate to determine, ultimately, the cost of equity. Table GJE-6, p. 15. The earnings growth rates from Value Line were dated June 6, 2003, while those estimates from First Call and Zacks were as of June 1, 2003.[12] Mr. Eckenroth addressed the importance of not relying on a single source of future data and used the three analyst services available to get as reliable as possible a consensus estimate of long-term growth based on earnings. As shown in Table GJE-5, p. 14, Mr. Eckenroth simply averaged the earnings growth rates, applying equal weight to each company in the proxy group. The dividend yield calculation was based on the average monthly high and low stock price for each proxy group company over the six- month period ending June 30, 2003. Eckenroth PFT, Exhibits GJE-3 and GJE-4.

As a check of "reasonableness" of the recommended ROE, Mr. Eckenroth employed the use of the risk premium model (RPM) to set the top end of that reasonableness range that resulted in a 12.07% cost of equity. The RPM methodology estimates the cost of equity by measuring the differential in investors' expected returns between debt and more risky equity. The risk premium model takes the basic form:

$$k = D + R_p$$

where:
k = Investors' required return or equity cost of capital
D = Cost of debt
R_p = Investors' risk premium over a debt instrument

The cost of debt can be measured as a risk free rate or the rate on a corporate or utility bond. Mr. Eckenroth utilized the Ibbotson return data contained in the SBBI Valuation Edition 2003 Yearbook for large company stocks and long-term corporate bonds, and concluded that the incremental yield, or risk premium applicable to CL&P of 6.17% or 617 basis points. The cost of debt was specified at 5.90%, equal to the 4.73% average yield on 30-year treasury bonds over the six-month period ending June 2003, increased by the credit spread of 117 basis points for A- and A2 rated 30-year utility bond as stated by Reuters (formally Bridge) Information Systems as of July 1, 2003. The risk premium of 6.17% added to the 5.90% cost of debt results in the ROE of 12.07%. When calculated using a long data series, Mr. Eckenroth believes that the historical average risk premiums remain relatively stable and supports the assumption that the past is reflective of future. Eckenroth PFT, pp. 17-22.

Although Mr. Eckenroth primarily relied on the ACE DCF method to formulate his recommended cost of equity, he employed an alternate DCF method termed the sustainable growth rate (SGR) formula. The SGR result of 10.17% was used to set the bottom end of a "range of reasonableness" for the ROE. The theory behind the SGR formula is that a company can only grow by what it reinvests and earns on that investment, whether it issues or retires stock during that period and the profitability of stock investments. Eckenroth PFT, pp. 23-28. The SGR is calculated using the formula:

[12] First Call and Zacks did not have an earnings projections for CV, GMP and MGE.

$g = br + sv$

where: b = expected retention ratio
r = expected earned rate of return
s = fraction of new common stock sold that accrues to the current stockholder
v = equity accretion ratio

The SGR formula is similar to the ACE DCF method because it uses the same method ($K=(D_0 x(1+g))/P_0+g$) to calculate the ROE. Mr. Eckenroth used the same results from the ACE calculations for the stock price, dividends and dividend yield. Id. For the most part, the difference between the two methods was due to source of growth rate used in each. Mr. Eckenroth used Value Line's projected earnings per share, dividends per share, book value per share, shares outstanding and price earnings ratio to calculate the earnings growth rate for the SGR DCF. According to Mr. Eckenroth, the inherent shortcoming of the SGR method is that it relies solely on one source of forecast data (Value Line) to calculate the earnings growth rate. Mr. Eckenroth noted that sustainable growth is derived from two components. One is growth that comes from retention of earnings, while the second component comes from growth in the number of shares of stock outstanding in the company.

In summary, Mr. Eckenroth's recommended ROE of 10.98% derived from the ACE DCF method is supported by the bottom range of 10.17% from the SGR formula to the top end result of 12.07% risk premium method. Mr. Eckenroth chose the 10.98% and then added 36 basis points for underwriting and issuances costs for a final recommendation of 11.34% cost of equity. However, the Company proposed to use 10.75% ROE.

In calculating the industry average flotation costs, Mr. Eckenroth used the mean of 3.57% from a Morgan Stanley compilation of common stock issuances for utilities beginning 1/1/2001 to 2/28/2003. Application, Exhibit GJE-10; Eckenroth PFT, pp. 29-32. To determine the flotation cost adjustment for CL&P, the standard flotation cost equation of $K=f*s/(1+s)$ was used and then the result was amortized over the four year rate plan period. Using the forecast of new CL&P equity, the flotation cost adjustment was calculated as follows: 3.57%*(447/721)/(1+(447/721)) = 1.37%/4 = .34%. Finally, a FERC[13] adder of .02% is included for a total flotation cost adjustment of 0.36%. Id.

c. Position of Parties

OCC's cost of equity recommendation in this proceeding was 9.30% based on the capital structure containing 34.93% common equity that was allowed in CL&P's prior rate case. OCC's cost of equity witness, Mr. Rothschild, employed the use of a simplified (constant or single stage) DCF, a complex (multi-stage) DCF, and a risk premium capital asset pricing model (CAPM) in developing its recommendation. Mr. Rothschild applied the simplified DCF method to both the Company's proxy group and an alternate group consisting of all the electric utilities covered by Value Line in its

[13] Due to a FERC ruling which recommended an allowance of two basis points. The FERC referenced formula $K'=fs/(1+s)$.

Eastern Electric Utility issue. Rothschild PFT, p. 10. The cost of equity results using the complex DCF method were based upon the Value Line companies only. Alternatively, it could be reasonable to consider using the average capital structure corresponding to the Eastern electric companies in Value Line, in that case Mr. Rothschild recommends a 9.20% cost of equity. Rothschild PFT, Schedule JAR 1.

OCC's simplified DCF method yielded a cost of equity ranging from 8.79% using average stock prices for year ended 8/31/03, to 9.08% based upon stock prices on 8/31/03, depending upon the group of companies used. Rothschild PFT, Schedule JAR 2. The results of the complex DCF method indicated a cost of equity ranging from 8.63% to 9.67%, based on the time period examined and the group of companies used. The complex or multi-stage model showed cash flows to investors consisting of annual dividends plus stock sale proceeds at the end of the term. In this regard, the model ultimately arrived at the stock price the investor would eventually receive if the stock was held till 2042. Rothschild PFT, Schedule JAR 5, p. 1. It then determined the discount rate that brings the total of the cash flows and the final stock selling price equal to the original stock purchase price of $33.05. Id.

Mr. Rothchild also performed a risk premium/CAPM analysis based upon long-term corporate bonds. One important fact that Mr. Rothschild points out when implementing the risk premium method is the equity risk premiums have declined during the past decade. This model incorporated an analysis of historic returns from 1926-2001 and was adjusted for electric distribution utility specific risk. The results of the CAPM method indicated a cost of equity ranging from 8.6% to 9.2%. Rothschild PFT, pp. 104-114 and Schedule JAR 2.

OCC believes that general trends in the capital markets and the new income tax law have already combined to cause a substantial lowering of the cost of equity below the 10.30% allowed in CL&P's last rate case. OCC states four factors that have lowered the cost of equity which include: 1) a general lowering in capital cost rates as indicated by the change in the long-term interest rate on U.S. Treasury bonds, 2) the tax on corporate dividends is now capped at 15% and the tax on long-term capital gains has been reduced from 20% to 15%, 3) an increase in the common equity ratio substantially reduces the financial risk experienced by CL&P, and 4) the transition of CL&P into a transmission and distribution only electric utility has further lowered the company's risk. Rothschild PFT, pp. 15-16.

OCC argued that Mr. Eckenroth's recommended cost of equity of 11.34% contains serious errors in the implementation of the equity costing methods presented. In summary, the major contention with Mr. Eckenroth's cost of equity computation is that he misapplied the DCF method by using a proxy for long-term growth based solely on earnings per share growth forecast for the five years from 2003 to 2008. Rothschild PFT, p. 17. OCC noted and Mr. Eckenroth agreed that the appropriate growth rate used in the constant growth DCF is one that is equal to or consistent with the growth in dividends, earnings, book value and stock price. Response to Interrogatory OCC-32. With respect to the risk premium method, Mr. Rothschild stated that Mr. Eckenroth failed to consider that the risk premium has been declining over time.

The underlying premise of Mr. Rothschild's analysis is that the proper cost of equity should be based on the appropriate capital structure that minimizes CL&P's overall cost of capital. OCC's recommendation produced an overall cost of capital of 7.61% based upon a cost of equity of 9.30% and a capital structure containing 34.93% common equity. Mr. Rothschild notes that the increase in CL&P's common equity ratio from 34.93% to 49.84% has occurred concurrent with only a modest increase in CL&P's bond rating from BBB+ to A-. Rothschild PFT, p. 9. Mr. Rothschild states that the extra cost of the higher level of common equity in the capital structure should be offset by a sufficient drop in the allowed ROE. Therefore, in the event that the Department adopts the capital structure as proposed by the Company, Mr. Rothschild recommends an 8.75% cost of equity and an overall cost of capital of 7.74%. Rothschild PFT, Schedule JAR 1.

Mr. Rothschild's recommended cost of equity does not reflect financing costs. If the financing cost computation was based upon the historic actual average from 1982 through 2003, then Mr. Rothschild recommended that the proper financing cost in this proceeding would be 0.034%, or about 3 basis points. As shown in response to Interrogatory OCC-14, the actual annual average amount for financing costs incurred by NU from 1982 through 2003 was $593,000, or only about 10% of the amount requested by Mr. Eckenroth. Mr. Rothschild argued that the flotation cost computation is so excessive because it incorrectly assumes that all of the Company's equity is reissued every year and none of the equity is raised through the retention of earnings. Rothschild PFT, pp. 71-72.

The AG supported the OCC's recommended ROE of 9.3%. The AG also agreed that the Company's cost of capital is lower due to the generally lower capital costs, decline in interest rates, lower tax rate for investors and its risk profile is much lower. Moreover, the AG urges the Department not to approve the Company's proposed deferred pension rate mechanism and proposed transmission rate adjustment mechanism in the determination of CL&P's ROE. If approved, the AG contends that the Department should lower CL&P's authorized ROE from 9.3% accordingly. AG Brief, 11/12/03, pp. 22-23.

Prosecutorial recommended a 10.05% return on common equity based on the capital structure proposed by the Company. With consideration given to flotation costs, the cost of equity considered reasonable ranges from 9.75% to 10.35%, with a midpoint of 10.05%. Prosecutorial agreed with OCC that the major contention with Mr. Eckenroth's cost of equity computation is the reliance solely on earnings growth forecasts as the substitute for investors' long-term growth expectation in the DCF equation. Prosecutorial regarded Mr. Eckenroth's growth rate conclusion as a simplistic and flawed outcome. Prosecutorial Brief, 11/12/03, p. 8. Therefore, Prosecutorial conducted its own calculations after an extensive review of all pertinent information in Value Line regarding growth rates. It should be noted that Prosecutorial prepared Late Filed Exhibits Nos. 65 and 66 in an attempt to provide a reasonable averaging technique of the growth rates and to illustrate the possibility that the forecasts may be inherently overstated. Prosecutorial Brief, 11/12/03, pp. 6-13.

Prosecutorial believes that the same criticism pointed at Mr. Eckenroth is applicable to OCC's DCF analysis in that they depend solely on an evaluation of one parameter, retention growth. Prosecutorial argued that a focus on retention growth alone will tend to underestimate the growth portion of return realized by investors and lead to cost of equity estimates that are too low. Prosecutorial Brief, 11/12/03, p. 12.

Prosecutorial pointed out some major discrepancies in the Company's application of the risk premium method. Prosecutorial believed there are two important weaknesses in the Company's approach. The first involves its failure to account for the extent to which utilities are less risky than the market as a whole, and the second concerns its failure to account for changes in the riskiness of debt versus equity that may be occurring overtime. Comparing the risk premium results of the Company and OCC, Prosecutorial does not believe that either side has successfully transformed historic risk premium data into a meaningful forward-looking estimate. Prosecutorial urges the Department to not give any weight to the risk premium results to avoid increasing the inaccuracy in the cost of equity decided upon in this proceeding. Prosecutorial Brief, 11/12/03, pp. 6-13.

d. Cost of Equity Analysis

The Department assessed the testimonies and recommendations of Mr. Eckenroth, OCC and Prosecutorial and is confident that the best solution to its cost of equity capital requirements exists within the framework of the DCF model. As stated earlier, the Company elected to utilize a 10.75% ROE in this rate proceeding for which it provided no calculations or analysis to support the proposed cost of equity. Apparently, the Department believes that the Company did not give any weight to its cost of equity witness' recommended ROE of 11.34% in electing to utilize a 10.75% ROE. The Department also carefully evaluated the growth rates proffered by the witnesses, since much of the disagreement over the DCF results centered on the choice and calculation of the growth rates.

1. Analysis of the Company's DCF Proposal

With regard to the choice of a proxy group, the Department accepts the Company's selection of its ten-member proxy group to measure its cost of equity. Such companies satisfied all criteria established in CL&P's study for proxy group membership.

The Department notes that in the 01-10-10 United Illuminating rate case cost of equity analysis, UI Holdings was included by the Company's witness as a member of the proxy group using in determining the cost of equity. However, in the current proceeding, the Company excluding its parent, Northeast Utilities, from such cost of equity analysis because of its high concentration (32%) of revenues in non-utility affiliates as of December 31, 2002. Eckenroth PFT, p. 10. The Department notes that the Company's criteria was to exclude those companies having non-utility revenues more than 20% of total revenues. The Department finds that based on the Company's criteria it is appropriate to exclude NU from such analysis.

After selecting the ten-member proxy group, the first step in the DCF is to calculate the average dividend yield. The Department believes the 4.74% average dividend yield as calculated by Mr. Eckenroth is reasonable. Eckenroth PFT, Table GJE-4.

Next step is the calculation of long-term earnings per share growth rates. Mr. Eckenroth's averaging of the earnings per share growth rates with the Company's proxy group was the subject of considerable controversy. The Department recognizes the Mr. Eckenroth relied exclusively on earnings growth rate projections published by three analyst services to get as reliable as possible a consensus estimate of long-term growth based on earnings. Although, Mr. Eckenroth addressed the importance of not relying on a single source of future information, the 5.97% growth rate outcome in Table GJE-5 is flawed because it is not based on an equal consensus of the available forecasts. As shown in Table GJE-5, CV, GMP and MGE are included in the calculation to determine the average growth rate despite that earnings growth estimates for these three proxy group companies are only available from one source, Value Line. This causes the Value Line estimates to be weighted more heavily relative to the other available forecasts, and increases the proxy group average growth rate significantly. For averaging purposes of Table GJE-5, each proxy group company should have its growth estimate measured on the same basis.

The Department agrees with Prosecutorial's approach of a reasonable averaging technique of growth rates by providing an equal consensus of the available forecasts included in Table GJE-5. As shown below in Late-Filed Exhibit No. 65, provided by Prosecutorial, it attempted to apply equal weight to the available growth forecasts. The following table recalculated the average earnings growth rate forecasts.

Earnings Growth Rates Equally Weighted (%)

Company	Value Line	First Call	Zacks	Average
CV	9.00%	n/a	n/a	
ED	1.00%	3.00%	3.11%	
EDE	10.50%	3.00%	6.50%	
EAS	1.00%	4.00%	4.83%	
GMP	10.00%	n/a	n/a	
MGE	6.00%	n/a	n/a	
NST	3.50%	5.00%	4.25%	
SCG	6.50%	5.00%	5.00%	
SO	6.50%	5.00%	4.85%	
WEC	8.00%	6.50%	7.14%	
Proxy Group Average				**5.38% ***

*5.38% = the sum of the 24 estimates divided by 24.

Using Mr. Eckenroth's earnings growth projections, the average growth rate for the proxy group becomes 5.38%, or 59 basis points less than the 5.97% determined by Eckenroth. The calculation shown above is simple. However, it relies exclusively on projected information and makes no attempt to represent the anticipated growth rate in dividends per share, book value per share, or stock price. Both OCC and Prosecutorial witnesses argue that reliance on forecast growth rates alone, absent an examination of all the underlying determinant of long-run dividend growth, gives no consideration to actual past earnings performance and will produce inaccurate DCF results. While Mr. Eckenroth does agree that investors should consider all information, Mr. Eckenroth believes that equity analysts' forecast of growth is obviously better than simply using historical growth rates because analysts have access to additional types of information. Eckenroth PFT, p. 13. Further, Mr. Eckenroth contends that by studying all available information specific to the industry, analysts would be more accurate than merely looking at historical information. Id.

Although the Department finds considerable amount of evidence supporting both historical and forecasted growth rate, a careful evaluation was made of the Company's earnings growth forecasts. The First Call and Zacks growth rates are 5-year growth rates in earnings per share (eps), and measure this eps growth from the most recently completed fiscal year (2002) until five years from the end of the fiscal year (to 2007). Of particular concern, were the earnings growth rate estimates Mr. Eckenroth used from Value Line. Mr. Eckenroth used a six-year growth rate from Value Line that computes the compound annual growth in eps from 2000-2002 to the average eps Value Line forecasts for 2006 to 2008. The 2002 actual earnings are now published, but Mr. Eckenroth used older data (2000 earnings) as a starting point. Mr. Eckenroth argues that by using a single year as a starting or ending point, the result will be distorted if that year was not representative. The Company believes it is for that reason that Mr. Eckenroth chose the Value Line earnings growth estimate that averages 3 years at the start and 3 years at the end, thereby mitigating such distortion. Late Filed Exhibit No. 63. While it could be presumed that a five-year growth rate will be highly skewed if the results from 2002 were somehow not representative or atypical, it is for this same reason that the Department finds it preferable to use a five-year growth rate with the most recent eps data available using 2002 as a starting point.

First, for consistency among the earnings growth estimates, the Company should have used a five-year eps growth projection with 2002 as a starting point for all three sources. Given the extent to which the estimates themselves differ from one analyst to another, each source should have its growth estimate measured on the same time period. The volatility and magnitude of divergence in the earnings forecasts between Value Line and First Call is apparent if one was to look at Table GJE-5. Second, Mr. Eckenroth failed to use the most recent (2002) eps Value Line data available for the proxy group. Obviously, the years 2000 and 2001 have elapsed, why forecast past events or old data.

The Department conducted an extensive review of the Value Line reports for growth rates from 2000-2002 to 2006-2008 for each proxy group company. For example, the first company in the proxy group is CV. The Value Line report indicates a 9.0% eps growth rate for that time period. The same exhibit also shows a 3% dividends per share (dps) forecast and a 2.0% book value per share (bvps) growth rate. The significant difference between the forecasted eps and the growth rate for dps and bvps is the first indication that the 9.0% eps forecast is unsustainable and therefore not representative of CV's recent growth. The report shows that CV earned 6.9% on its common equity in 2000, earned 5.8% in 2001, and 9.3% in 2002, for an average ROE of 7.33% over the 2000-2002 starting period. For 2006-2008 ending period, Value Line is forecasting 11% ROE. Obviously, in a time period when the ROE is increasing from 7.33% to 11%, the eps growth rate will be atypically high. CV is just one example where choosing an earnings growth estimate that averages 3 years at the start and 3 years at the end, does not mitigate such distortion. In fact, Mr. Eckenroth testified that analyst forecasts could not have prophesied such events as war, "9/11", restructuring, recession and the major changes in the capital market. Tr. 11/17/03, pp. 1866-1868. Conversely, Mr. Eckenroth used an earnings growth estimate that averages the years that these major events took place.

The Department asked the Company to recalculate the average growth rates shown in Tables GJE-5 and GJE-6 using the methodology approved in Decision dated September 26, 2002 in Docket No. 01-10-10, DPUC Review of The United Illuminating Company's Rate Filing and Rate Plan Proposal.

Earnings Per Share Growth Rates

Company	Value Line %	* Adjusted Value Line %	First Call %	Zacks %
CV	9.00%	5.37%	N/a	N/a
ED	1.00%	0.44%	3.00%	3.11%
EDE	10.50%	9.81%	3.00%	6.50%
EAS	1.00%	5.92%	4.00%	4.83%
GMP	10.00%	2.34%	N/a	N/a
MGE	6.00%	5.89%	N/a	N/a
NST	3.50%	3.43%	5.00%	4.25%
SCG	6.50%	6.43%	5.00%	5.00%
SO	6.50%	4.90%	5.00%	4.85%
WEC	8.00%	3.46%	4.85%	7.14%
Average	6.20%	4.80%	4.50%	5.10%

Source: Late Filed Exhibit No. 63

The above exhibit shows the adjusted Value Line earnings growth estimates based on a five-year growth rate with the most recent eps data available using 2002 as a starting point. The adjusted Value Line earnings growth rates better compare to earnings growth estimates of First Call and Zacks. Using the adjusted Value Line earnings growth estimates and restating the average growth rate forecasts, the average for the proxy group turns out to be 4.80% (equals the sum of the 24 estimates divided by 24).

The Department believes that Mr. Eckenroth's 5.97% average growth rate projection for the proxy group is not representative of the actual investor-expected growth rate in the Company and was not based on an equal consensus of the available forecasts. The Department finds the average growth rate estimate of 4.80% to be appropriate for the proxy group as discussed above. The Department made certain adjustments to the Company's DCF calculations as summarized below.

* Department Adjusted
DCF Calculation

Company	Dividend Per Share	Average Stock Price	Dividend Yield %	Adjusted Yield %	Average Annual Growth	DCF ROE %
CV	$0.88	$17.87	4.92%			
ED	$2.24	$40.51	5.53%			
EDE	$1.28	$19.14	6.69%			
EAS	$0.99	$19.79	5.00%			
GMP	$0.71	$20.47	3.47%			
MGE	$1.36	$28.45	4.78%			
NST	$2.15	$42.88	5.01%			
SCG	$1.32	$31.39	4.21%			
SO	$1.36	$29.29	4.64%			
WEC	$0.80	$25.76	3.11%			
Average	$1.31	$27.56	4.74%	4.96%	4.80%	9.76%

Source: Mr. Eckenroth's DCF construct modified per the Department's review of Value Line's data in Exhibit GJE –5.

In general, the DCF model is implemented by adding the dividend yield to an estimated growth rate. The Department accepts a reweighting of the earnings growth estimates and the inclusion of the adjusted Value Line growth estimates. This results in an estimated cost of equity of 9.76%.

2. Analysis of OCC's DCF Proposal

Before determining the appropriate cost of equity for the Company, the Department also assessed the analyses of OCC's cost of capital witness, Mr. Rothschild. The Department finds that Mr. Rothschild's complex or multi-stage DCF model is a reasonable approach to measuring that which investors expect to receive. OCC's DCF method attempts to measure the return investors expect to get focusing primarily on retention growth. The first stage of the DCF analysis used actual dividend rates forecasted year by year in Value Line. The Department finds that the first stage of this model reflects accuracy and no particular bias in calculating anticipated cash flows.

For the second stage of the model, Mr. Rothschild used a fixed expected return on equity and a fixed market-to-book ratio in all years of the calculation. In reviewing Value Line's expected return data provided by Mr. Rothschild in Schedules JAR 3, p. 2 and JAR 4, p. 1, it indicated a range between 10.5% median (low-end) and an 11.4% mean (high-end). Instead, Mr. Rothschild input a 10.0% (low-end) and 11.0% (high-end) expected return into the multi-stage model. Using the 11.0% and 10.0% returns and forecast retention rate, Mr. Rothschild determined a cost of equity of 9.5% and 8.63% based upon prices on August 31, 2003, respectively. The Department believes that Mr. Rothschild's expected return inputs of 10% and 11% to be low and not representative of the average Value Line projected return on equity. Adjusting the projected return inputs to the appropriate range as indicated by Value Line's data (10.5% and 11.4%), keeping all else equal, would raise the cost of equity result by almost 50 basis points. Tr. 10/29/03, pp. 3441-3442. This adjustment to the expected return inputs under OCC's multi-stage version of the DCF, all else equal, would raise the cost of equity range of 9.13% to 10.0%.

3. Analysis of the Risk Premium Methodology

With regard to the Company's approach to the risk premium method, some problems quantifying the risk premium were identified by OCC and Prosecutorial. First, Mr. Eckenroth failed to account for the extent to which utilities are less risky than the overall market. Mr. Eckenroth used the returns achieved by large company stocks and long-term corporate bonds which is estimated to have a beta of 1.0, signifying that they have a risk equal to the market as a whole. However, the average beta of his proxy group of electric utilities is 0.58%, suggesting an applicable risk premium for CL&P is approximately half of the 617 basis points actually attributed to Mr. Eckenroth's risk premium result of 12.07%. The second concern, involves its failure to account for changes in the riskiness of debt versus equity that may occur over time. Mr. Rothschild argues that Mr. Eckenroth made no adjustment to correct for either the down-trend that has occurred in risk premiums since 1926 or the inherent overstatement of the risk premium that happens as a result of the use of arithmetic average versus geometric mean. Rothschild PFT, pp. 56-57.

As Prosecutorial points out, the objective of using any cost of equity model should be to enhance the accuracy of the final result. The range of estimates between Mr. Rothschild and Mr. Eckenroth from roughly 200 to 600 basis points, respectively, based on using different debt and equity securities and different time periods for its measurement, and the many interpretations of how it may be measured (geometric versus arithmetic), it is reasonable to conclude that the risk premium approach suffers from so much subjectivity that it can essentially be used to produce whatever outcome is desired. Prosecutorial Brief, p. 8. Comparing the testimonies of the two cost of capital witnesses, it is evident that the interpretation of the risk premium data and the implementation of a risk premium study is subjective, requiring a great amount of professional judgment. Id.

The Department finds Mr. Eckenroth's 12.07% risk premium cost of equity result is overstated because it does not include a beta adjustment to account for the lower risk and return expectations for utility stocks. The Department also believes Mr. Rothschild's 8.6% to 9.2% range using the CAPM method is understated. Perhaps the subjectivity is best noted by the Company itself since it opted to use 10.75% as an equity cost in the ratemaking capital structure. Both Mr. Rothschild and Mr. Eckenroth did not give their risk premium conclusion any weight in coming up with their final ROE recommendations.

For all the reasons discussed above, and absent any attempt to transform historic risk premium data into a meaningful forward-looking estimate, the Department has evaluated the results of the risk premium analyses, however, places greater emphasis upon the DCF analyses and less upon risk premium results.

Nevertheless, the Department estimated a CAPM cost of equity using the standard formula K= Rf + B(Rm - Rf). This calculation utilized an estimated risk free rate (Rf) of 5.30% (interest rate on 20-year treasury bonds), the proxy beta (B) of approximately .58, and the arithmetic mean return from 1926 to 2001 on Large Company Stocks (Rm) of 12.65%. Schedule JAR 10, p.1 and p. 3; Accordingly, the

Department calculated the cost of equity under the CAPM approach to be 9.56% [5.30% + .58(12.65% – 5.30%)].

4. Flotation Costs

The Department considered the Company's recommendation for a return for its selling and issuance costs. The Company is requesting a maximum flotation cost adjustment of approximately 36 of basis points, using the forecast of $447 of new equity to support its construction program over the four year rate plan. Mr. Eckenroth divided the amount of the new equity by the total equity CL&P projects to have at the end of 2003. To determine the flotation cost adjustment for CL&P, the standard formula as referenced by a FERC ruling of K=f*s/(1+s) was used and then the result was amortized over the four year rate plan. However, it should be noted that the Company did not request its recommended ROE of 11.34% but instead reflected 10.75% in its revenue requirement calculations. Response to Interrogatory OCC-48. It is not clear from the Company's testimony whether and to what extent the adjustment for flotation costs is included in the 10.75%.

OCC argued that Mr. Eckenroth's financing cost computation is so excessive because his quantification of financing costs incorrectly assumes that all of the Company's equity is reissued every year and none of the equity is raised through the retention of earnings. Rothschild PFT, pp. 71-72. In response to Interrogatory OCC-48, Mr. Eckenroth acknowledged that the requested 0.34% (excluding the .02% FERC adder) provides CL&P with $5.8 million per year for financing costs. Compared to the historic actual average for financing costs incurred by CL&P, Mr. Rothschild contends that this should be only about 10% or the amount requested or 0.034%. Further, OCC believes even the 3 basis points overstates financing costs because it is based upon the entire NU rather than an allocation to CL&P.

The Department finds that based on historical data provided by the Company, the amount of equity provided by its parent and the Company's retained earnings has varied from 22% retained/78% parent in 1998, to 46.9% retained/53.1% parent in 2002. OCC 48, Data Request OCC-01, p.3. Further, such percentage from retained earnings has increased each year since 1999. Accordingly, the Department believes it reasonable to assume retained earnings may continue to contribute to equity in amounts that would lessen the level of stock infusions needed from the parent. As well, the Department has made various downward adjustments to the capital expenditures allowed in this proceeding which would also reduce the need for stock issuances by the NU parent. Therefore, the Department finds it reasonable to make some adjustment to the Company's proposed flotation costs. Given these findings, the Department finds it reasonable to allow 20 basis points for flotation costs in CL&P's cost of equity.

The need for a downward adjustment to the Company's ROE was evident in evaluating CL&P's regulated business against the proxy group DCF. In this regard, various of the proxy group companies contained both regulated and unregulated operations, therefore a general risk profile that was greater, and requiring a higher return, than CL&P's regulated lines. Since the charge of this proceeding was to determine the return for CL&P's regulated operations, the proxy group results overstated this return.

The Department analyzed a considerable breadth of information presented in this proceeding in order to determine the appropriate return on equity to allow CL&P. The Department was unable to substantiate maintaining the Company's currently allowed ROE of 10.3%. This was attributable to both the technical analysis and a variety of changes in key factors surrounding the financial setting of such ROE. Several important factors have changed since the last time the Department set CL&P's ROE in 1998 which support a lower allowed return at this time. Some of these factors included: 1) CL&P's overall financial strength has improved, 2) interest rates are more favorable, 3) business risk has declined attributable to the Company divesting itself of generation, and 4) the tax on corporate dividends is now capped at 15% and the long-term capital gains have been reduced from 20% to 15%. The Company, however, did not explicitly consider these factors in their analysis. A discussion of these items is as follows:

First, CL&P's financial strength has improved considerably. In 1998, when CL&P's ROE of 10.3% was set, the Company exhibited a Moody's bond rating of Ba2 and an S&P rating of BBB-. In 2003, Moody's rating improved to A2 and S&P rated CL&P's debt A-. Response to Interrogatory EL-9. Higher bond ratings mean greater financial strength. In 1998, CL&P's capital structure contained 33.4% common equity, it improved to 51.1% at year-end 2002. This is a substantial difference in capital structure. In this regard, a greater percentage of equity in the capital structure implies less risk to the investor and therefore a lower required ROE.

Second, the interest environment, itself, has changed since the time of the last rate setting proceeding. In October 1998, yields on 20-year treasury bonds were approximately 5.5%. In 2003, such treasury yields have been in the mid to lower 5% range (approximately 5.3%). Rothschild PFT, JAR 10, p.1; Response to Interrogatory EL-9. This has placed downward pressure on what equity investors can expect out of stock returns attributable to the fact that their alternatives, such as bonds, are yielding less. Lower interest rates are taken into account in the expected rate of return of investors in the DCF analysis but even more directly in the risk premium methods (risk premium/CAPM).

Third, CL&P's risk has also declined significantly since electric restructuring. In 1998, CL&P was a fully integrated electric utility having a significant portfolio of generation facilities that included nuclear plants. Subsequent to deregulation, CL&P became a transmission and distribution company only, and only recently sold its interests in Seabrook Nuclear and Millstone. Generation is more risky than distribution business and nuclear adds to that risk. Generation is generally more risky because it is more subject to operational failures, uncertain costs of operation and prudence reviews. In addition, according to S&P Benchmarks, CL&P's business risk decreased from 7 in 1998 to a business risk of 4 in 2003. Response to Interrogatory EL-9. Generally, the sale of generating assets enhanced the Company's business profile, with management focusing on the lower-risk transmission and distribution system. Risk is also reduced since a higher proportion of distribution costs are collected through fixed customer service and demand charges than in the past. The collection of costs through fixed charges rather than energy charges reduces the variability of earnings associated with sales.

Fourth, there has been a substantial reduction to the income tax rate paid by investors in common stocks. A new tax law was passed in late May 2003, that lowers the federal income tax rate on dividends to 15%, and the tax on long-term capital gains has been reduced from 20% to 15%. Both of these changes have caused common stock investments to become relatively more attractive to investors than they were since the time of CL&P's last rate case in 1998. Rothschild PFT, p. 16. OCC argues that it may not be possible to precisely determine the cost of equity impact, but it is reasonable to assume that the new tax law would lower the cost of equity. Conversely, Mr. Eckenroth believes the market is efficient and stock prices should reflect all available information and investor expectations regarding the tax law changes. Eckenroth PFT, p. 16. The Department generally agrees with the OCC, but recognizes there is considerable debate regarding this change in taxation of dividends and the impact it would have on the cost of equity analyses making it difficult to precisely estimate the impact on cost of equity. Therefore the Department did not make a specific adjustment, however, it provides further justification that a lower ROE is warranted.

Finally, expectation for all stocks have generally declined since the market downturn from 2000 through 2002. Most analysts now estimate returns more in line with historical averages or lower. This is reinforced by CL&P's own testimony regarding its pension plan. CL&P testified that long-term expectation for its overall pension return, which is approximately 70% equity, should be lowered from 9.25% in 2002 to 8.75%.

A summary of the Department's analysis of the cost of equity allowed is as follows:

Summary of Department Analysis Cost of Equity Allowed	Presented	Department Adjusted
Company proposed ROE	* 10.75%	
Company Witness DCF	10.98%	9.76%
Company Witness Risk Premium	12.07%	
OCC DCF Analysis	8.63% to 9.5%	9.13% to 10.0%
OCC Risk Premium/CAPM	8.6% to 9.2%	
Prosecutorial DCF Analysis	10.05%	
Department CAPM		9.56%
Department Allowed		9.55%
Company Flotation	0.36%	
OCC Flotation	0.034%	
Department Flotation Allowed		0.20%
Final Department Allowed Cost of Equity		9.85%

e. Conclusion on Cost of Equity

In determining the cost of equity, the Department considered all of the witnesses' cost of equity analyses. The Department finds that CL&P is a company that now has less risk, both financially and operationally. Consequentially, in regulating CL&P to allow a return commensurate with its needs, the Department has determined that its investors now require less of the Company in financial return than in 1998, when the return was established at 10.3%. Therefore, in consideration of the arguments of the Parties and Intervenors, the Department believes that a reasonable range is 9.13% to 9.76%. Therefore, the Department determines that 9.65% is a reasonable cost of equity for CL&P. Adding to this a reasonable return for flotation costs, the Department allows the Company a final cost of equity of 9.85%, and adopts such return in this proceeding. Accordingly, 9.85% shall also be CL&P's allowed return on equity (ROE) on the equity portion of its rate base.

The Department notes that legislation allows CL&P to earn additional revenues that are not considered for ratemaking purposes or the Company's earnings sharing but increase overall returns to its shareholders. The Company is allowed up to 5% (after tax) bonus rate of return on conservation investments. This is potentially $2.5 million in 2004. In addition, CL&P is allowed a procurement fee and potential incentive for the procurement of transitional standard offer generation service. The procurement fee is equal to 0.5 mills per kilowatt hour for transitional standard offer service. Regarding the procurement incentive, CL&P may earn 0.25 mills compensation for mitigating the prices of the contracts for the provision of electric generation services. The procurement fee and the incentive could result in as much as $17 million in additional revenues.

6. Weighted Cost of Capital

The Company proposed a ratemaking capital structure consisting of 49.84% equity and 43.38% leverage based on the average capitalization for the 2004 forecast year. CL&P's proposed capital structure derives a weighted cost of capital of 8.76%. On a rating agency basis, CL&P's proposed capital structure is translated to 45% equity and 55% debt to maintain its credit quality. McHale PFT, pp. 3-4. The difference between the ratemaking and rating agency capital structure is caused by the dissimilar treatment of the prior spent nuclear fuel obligation (PSNF), preferred stock, capital leases and short-term debt.

On a rate-making basis, where debt is reduced, CL&P's targeted common equity position alone (excluding preferred) is 49.84% of capitalization. CL&P excludes from debt approximately $218 million in PSNF liability, $15 million of capital leases, and $70 million in short-term debt. Under such basis, the percentage of equity in the capital structure is higher since debt levels have been reduced. It is on the rate-making basis the capital structure that is used in developing CL&P's cost of capital and revenue requirements.

CL&P notes that its proposed capital structure recommendation is premised upon a capitalization which: a) maintains a strong "BBB" credit rating, b) provides the Company with timely access to competitively priced capital, c) provides the Company with a degree of financial flexibility, and d) balances these factors in developing the lowest weighted average cost of capital to minimize capital cost for its customers. McHale PFT, p. 3.

Aside from the equity cost rate issue, OCC's concern is the overall cost of capital for cost minimization purposes. As required in Decision dated December 12, 2001 in Docket No. 01-07-02, <u>DPUC Review of The Connecticut Light and Power Company's Capital Structure</u>, CL&P was to maintain or reduce its relative allowed cost of capital by the Company's next rate hearing. OCC argued that CL&P did not provide any evidence supportive of the fact that its ongoing capital structure strategies have resulted in the maintenance or reduction of CL&P's allowed cost of capital as required. The OCC recommended a capital structure consistent with CL&P's last case (34.93% common equity, or about 42.47% equity (including preferred)), resulting in a cost of capital of 7.61%.

The Department has considered OCC's recommendation carefully. However, S&P credit rating criteria submitted by the Company indicates that the minimum capitalization necessary for a company such as CL&P to maintain a "BBB/A" rating is 57% debt and 43% equity. McHale PFT p. 8, Table DRM-3. While other criteria are considered, it appears advisable for CL&P to maintain such minimum threshold (43% equity including preferred) in this component of the rating analysis. Therefore, the

Department does not agree with OCC's proposal that would drop equity levels below 43% as determined by the rating agencies or 47.22% on a rate-making basis.

After study and deliberation of all cost of capital issues presented in this proceeding, the Department finds that 8.19% is a fair rate of return. The approved capital structure and capital cost on the rate-making basis is followed:

Allowed Weighted Cost of Capital

Capital	Ratio	Embedded Cost	Weighted Cost
Long-Term Debt	46.01%	6.95%	3.20%
Preferred Stock	6.78%	5.09%	0.34%
Common Stock	47.22%	9.85%	4.65%
Total	100.00%		8.19%

The Department finds that these rates, when applied to the rate base found reasonable for the Company, should produce operating income sufficient for CL&P to operate successfully and serve its ratepayers, maintain its financial integrity, and compensate investors for risks assumed.

I. Earnings Sharing Mechanism

CL&P proposes that its existing ESM, which provides for sharing of earnings in excess of its allowed ROE 50/50 between customers and shareholders, remain in effect over the distribution service plan. The Company proposes that the sharing would be calculated on a calendar year basis for each of the four years in the rate plan. PFT. Soderman, p. 17. Under the Company's ESM, the customer's share is used to write-off stranded cost

OCC proposes that the ESM should be implemented in such manner such that 50% of any earnings in excess of an ROE of 9.30% in any calendar year would be credited to customers in the following calendar year, and 50% would be retained by the Company. OCC recommends that earnings for sharing will be measured on a prospective basis for calendar years 2004-2007. 11/12/03 OCC Brief, p. 87. Under OCC's proposed ESM, ROE measurement for CL&P would be determined as follows:

- All fixed and variable costs of Northeast Utilities aircraft shall be excluded from operating expenses for purposes of ESM and CL&P's quarterly earnings reports filed with the DPUC.
- CL&P shall not include any amount of alleged prepaid pension asset in rate base for purposes of calculating ROE for its ESM or quarterly earnings reports filed with the DPUC.
- The expense for Directors and Officers liability insurance reflected in operating expenses shall be limited to the 2002 pro forma level of $359

thousand for purposes of ESM and CL&P's quarterly earnings reports filed with the DPUC.

- The amount of cash working capital allowance includable in rate base shall be limited to CL&P Distribution revenues and expenses, as per the calculation shown on Exhibit LA-1s, Schedule B-5, and non-cash items shall be excluded from the cash working capital allowance for purposes of ESM and CL&P's quarterly earnings reports filed with the DPUC.
- Income tax expense will be adjusted for interest synchronization, using the calculation method shown on Exhibit LA-1s, Schedule C-18, for purposes of ESM and CL&P's quarterly earnings reports filed with the DPUC.

The Department has examined the OCC's concerns and addressed them as appropriate throughout the Decision. The Department finds that continuance of the basic mechanics of CL&P's current ESM is appropriate. Accordingly, the Company's excess earnings over its allowed ROE of 9.85%, calculated by the cost of capital method, will be shared 50/50 ratepayers/Company. The manner of application of the ratepayers' share of such excess earnings will be determined by the Department at the time of such sharing. As indicated herein, the Company's proposed accounting treatment for the prepaid pension asset is denied, therefore all ROE calculations will not be affected by such proposed treatment. Further, the Department disallowed the cost of the corporate aircraft. CL&P shall not include such costs in the ROE calculation. The Department has indicated in the Decision that it will monitor the impact of the capital expenditures and employee additions. If the Department determines that the Company is not making the expenditures that have been approved in this case and such reductions result in over-earnings, earnings sharing may be adjusted to provide a greater portion of excess earnings for ratepayers.

J. PREPAID PENSION ASSET

The Company has requested that the Department allow an accumulated prepaid pension asset of $275 million ($251 million related to distribution as of year end 2002) into rate base for the exclusive purpose of affecting the ROE calculation throughout the rate plan period. The Company indicates that the revenue requirement impact associated with including CL&P's prepaid pension asset in rate base would be an increase of approximately $21.4 million in the rate year. Response to CIEC-74.

CL&P notes that when the Company records a credit to pension expense, the offsetting debit is to the prepaid pension asset account. CL&P indicates that in the late 1980's and 1990's the market performance of the pension plan assets was greater than originally projected, which resulted in a negative pension expense for many years. Response to Interrogatory EL – 41, p. 1. A negative pension expense indicates that past contributions to the pension plan plus the returns on the pension plan assets are more than sufficient to cover the current year cost of the pension obligation. PFT, Soderman, p. 15. The Company notes that when pension expense is negative, customers' rates include a negative amount or a credit to effectively return to them the excess cash contributions that were made in the past. PFT, Soderman, p. 15.

Tab G

LEXSEE 2003 N.Y. PUC LEXIS 474

Minor Rate Filing of Crown Point Telephone Corporation for Approval to Increase Local Rates by $ 86,116 Annually

CASE 02-C-1293

New York Public Service Commission

2003 N.Y. PUC LEXIS 474

August 27, 2003, Issued and Effective

CORE TERMS: non-regulated, historic, plant, regulated, telephone, intrastate, royalty, accounting, salary, peer group, reduction, customer, payroll, staff, settlement, annual, internet, affiliate, allocate, deferred, rate base, directory, depreciation, imputation, excessive, deferral, depreciation expense, main building, affiliated, allocating

DISPOSITION: [*1] ORDER DENYING RATE INCREASE

PANEL: COMMISSIONERS PRESENT: William M. Flynn, Chairman; Thomas J. Dunleavy; James D. Bennett; Leonard A. Weiss; Neal N. Galvin

OPINION: At a session of the Public Service Commission held in the City of Albany on July 23, 2003

BY THE COMMISSION:

INTRODUCTION

On September 30, 2002, Crown Point Telephone Corporation (Crown Point or the company) filed the tariff revisions listed in Appendix A to increase its local service rates effective March 1, 2003. n1 In its filing, the company indicated that it had a revenue deficiency of approximately $ 370,000. However, in order to avoid increasing residential customer rates above the comparable Verizon New York Inc. (Verizon) rate and to partially mitigate what might otherwise be an objectionable local rate increase, the company limited its requested increase in local service revenues to $ 86,116. The company also requested permission to reverse a 1996 Commission order that required the New York Intrastate Access Settlement Pool (the Access Pool) to reduce the company's intrastate access settlements by $ 35,064 to address an overearnings situation. n2 The increase in local service rates combined with the reversal of the 1996 [*2] Commission action would result in an increase in intrastate revenues of $ 121,180 annually.

n1 The company subsequently postponed the effective date of the tariff revisions to August 1, 2003 to allow sufficient time for review.n2 Case 96-C-0015, Petition of Citizens Telephone of Hammond, Inc., Crown Point Telephone Company, Inc., Edwards Telephone Company, Inc., Germantown Telephone Company, Inc., Nicholville Telephone Company, Inc., and Newport Telephone Company, Inc. for authority to reduce their annual revenues to reflect excess earnings and/or benefits from the Tax Reduction Act of 1986, Approved as Recommended and so Ordered by the Commission (issued January 18, 1996).

The proposed tariff revisions would have increased both basic residential rates and business rates by 57%. Increases to the Service Order Charge, Central Office Line Charge and Premises Visit Charge were also proposed.

A review of the filing resulted in numerous adjustments, which yielded a total revenue decrease of $ 6,837. The company's [*3] rates will not be adjusted at this time. A deferral will be established to preserve this potential reduction in rates as an offset to expected future rate needs. A calculation of the revenue requirement is shown in Appendix B. A short form order denying the rate increase was issued on July 25, 2003. n3 that Crown Point's rate base and related depreciation expense are not overstated, when the company requests rate base treatment for this new telephone plant in its next rate filing, the company must be able to demonstrate [*45] that it has a process in place to identify the individual equipment items (and related dollar amounts) that comprise the company's TPIS balance. This process must also include a program to identify unrecorded retirements and a plan to take appropriate corrective actions. By having this process in place, a link can be made between the amount on the books and an item of physical TPIS, which allows for verification of the dollar value associated with these assets. This, in turn, will insure that customers are only paying for TPIS that is being used in utility service and properly included in the company's financial statement plant balance.

n11 Case 01-C-0597, Petition of Crown Point Telephone Corporation for Authority to Issue Mortgage Notes to the United States of America and to Rural Telephone Bank in the Amount of $ 1,825,000 and the Approval of an Amending Telephone Loan Contract to Secure the Same, Order Authorizing Financing (Issued October 24, 2001).

Rate of Return

Crown Point provided an average historic [*46] test year capitalization for the year ended June 30, 2002. This calculation produced a rate of return of 8.00% based on a common equity ratio of 62.38% and an equity return of 9.79%. Crown Point based its equity return on a rate set in Attachment B from the Financial Relief Process Joint Report in Case 02-C-0595, dated September 3, 2002. Updating this return on equity for interest rate conditions results in an allowed return on equity of 8.93%. This result is consistent when compared with a proxy group of telecommunications companies that provide local service and other recent Commission decisions.

We adjusted the company's capital structure, which impacted the weighted cost of debt. Crown Point did not include Unamortized Debt Expense and related amortization in the company's capital structure and cost of debt, respectively. This adjustment increases the company's weighted cost of debt from 1.85% to 1.96%. The resulting overall rate of return for Crown Point is 7.53%. The company's capital structure and cost rates are as follows:

Capitalization Component	Amount	Ratio	Cost Rate	Weighted Cost
Common Equity	$ 4,761,062	62.38%	8.93%	5.57%
Notes Payable	216,336	2.83%	4.75%	0.13%
Long Term Debt	2,655,397	34.79%	5.26%	1.83%
Total	$ 7,632,795	100.00%		7.53%

[*47]

CONCLUSION

Analysis of the company's proposal indicates that a revenue decrease of $ 6,837 is appropriate at this time. However, due to the uncertainties relating to the Intrastate Access Settlement Pool proceeding, we do not propose to change the company's rates. Instead, the company will implement deferral accounting treatment for the $ 6,837 annual excess revenues that the company is currently collecting from customers. In addition, the company will be required to accrue carrying charges at the company's pre-tax rate of return in amounts preserved for future disposition as of August 1, 2003. This deferral, along with the excess federal lifeline support and royalty, will be available for Commission disposition in a future Crown Point rate filing. Because the company may file for a rate increase when the Access Pool proceeding is resolved, we encourage the company to work with staff to utilize the moneys available as a result of this case to mitigate potential future rate increases. The company should meet with staff within 60 days of the issuance of this order to discuss the possibility for a multi-year rate settlement that would encompass the phase-out of the Access Pool, the [*48] continued reductions in the company's operating expenses, plant additions and CPR revisions, a possible plan to reduce the level of the royalty and the treatment of the aforementioned deferrals.

The Commission orders:

1. The petition of Crown Point Telephone Corporation to increase rates by $ 121,180 is denied.

2. Crown Point Telephone Corporation is directed to record a deferred credit in Account 4360, Other Deferred Credits, associated with the increased federal lifeline support as described in this Order and the Order issued December 24,

1997 in Cases 94-C-0095 and 28425. The company shall also record the deferred federal income taxes associated with this deferral.

3. Crown Point Telephone Corporation is directed to record a deferred credit in Account 4360, Other Deferred Credits, associated with royalty revenues from the company's non-regulated operations as described in this Order. The company shall also record any related federal income taxes entries that may be required.

4. Crown Point Telephone Corporation is authorized to defer expenses, not to exceed $ 30,000, associated with this rate case, in Account 1439, Deferred Charges. Consistent with the revenue requirement [*49] calculation in this Order, the company is directed to amortize these expenses over a three-year period beginning August 1, 2003. The company is also directed to record the deferred federal income taxes associated with these accounting entries.

5. Crown Point Telephone Corporation is authorized to defer expenses associated with litigation expenses from the E-Loan Buried Cable Construction Project in Account 1439, Deferred Charges. The company is also directed to record the deferred federal income taxes associated with this deferral.

6. Crown Point Telephone Corporation is directed to begin deferring on a monthly basis $ 6,837 in excess annual revenue requirement, as described in this Order. The company is also authorized to make any related federal income tax entries that may be required.

7. This case is closed.

Appendix A

CASE 02-C-1293

CROWN POINT TELEPHONE CORPORATION

P.S.C. No. 5 -- Telephone

Section 3

Second Revised Page 2

Third Revised Page 6

Second Revised Page 19

Section 5

First Revised Page 2

Attachment A

First Revised Page 1

First Revised Page 2

First Revised Page 3

Third Revised Page 2

Issued: September 30, 2002

Effective: March 1, 2003*

*Postponed to August 1, 2003 by [*50] Supplement Nos. 1, 2 and 3.

Appendix B

CASE 02-C-1293

Schedule 1

Crown Point Telephone Corporation

Income Statement - Intrastate

Tab H

LEXSEE 2003 N.J. PUC LEXIS 248

IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF AN INCREASE IN AND ADJUSTMENTS TO ITS UNBUNDLED RATES AND CHARGES FOR ELECTRIC SERVICE, AND FOR APPROVAL OF OTHER PROPOSED TARIFF REVISIONS IN CONNECTION THEREWITH
IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF ITS DEFERRED BALANCES RELATING TO THE MARKET TRANSITION CHARGE AND SOCIETAL BENEFITS CHARGE
IN THE MATTER OF THE CONSUMER EDUCATION PROGRAM ON ELECTRIC RATE DISCOUNTS AND ENERGY COMPETITION - JERSEY CENTRAL POWER & LIGHT COMPANY'S VERIFIED PETITION FOR DECLARATORY RULING
IN THE MATTER OF THE VERIFIED PETITION OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR REVIEW AND APPROVAL OF COSTS INCURRED FOR ENVIRONMENTAL REMEDIATION OF MANUFACTURED GAS PLANT SITES AND FOR AN INCREASE IN THE REMEDIATION ADJUSTMENT CLAUSE OF ITS FILED TARIFF IN CONNECTION THEREWITH
IN THE MATTER OF JERSEY CENTRAL POWER & LIGHT COMPANY FOR INCREASES IN ITS LEVELIZED ENERGY ADJUSTMENT CLAUSE CHARGE AND DEMAND SIDE FACTOR

DOCKET NO. ER02080506; DOCKET NO. ER02080507; DOCKET NO. EO02070417; DOCKET NO. ER02030173; DOCKET NO. ER95120633

New Jersey Board of Public Utilities

2003 N.J. PUC LEXIS 248

August 1, 2003, Dated

CORE TERMS: customer, amortization, deferred, settlement, recommended, energy, audit, reliability, annual, merger, transition, disallowance, base rate, ratepayer, recommendation, reduction, deferral, interim, rate of return, restructuring, electric, kwh, depreciation, monthly, charitable contributions, final decision, amortization expense, calculated, affiliates, prudency

PANEL: [*1] JEANNE M. FOX, PRESIDENT; FREDERICK F. BUTLER, COMMISSIONER; CAROL J. MURPHY, COMMISSIONER; CONNIE O. HUGHES, COMMISSIONER; JACK ALTER, COMMISSIONER

OPINIONBY: FOX; BUTLER; MURPHY; HUGHES; ALTER

OPINION: ENERGY SUMMARY ORDER

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Summary Order memorializes, in summary fashion, the action taken by the Board of Public Utilities ("Board" or "BPU") in these matters at its July 25, 2003 public agenda meeting by a vote of five Commissioners. This Summary Order is being issued for the purpose of implementing new rates on August 1, 2003, consistent with the requirements of the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et seq., and the Board's Orders implementing EDECA. The Board will issue a more detailed Final Decision and Order in these matters, which will provide a fuller discussion of the issues as well as the reasoning for the Board's determinations.

3. Performance Standards

The Board has long had a concern with reliability in JCP&L's service territory. The Board has conducted and is currently [*22] conducting reviews and focused audits related to service problems. There have been a number of outages in recent summers, most notably in 1999 in Red Bank. *I/M/O the Proposal to Perform a Review and Investigation of New Jersey's Electric Utility Systems,* Dkt. No. EX99070483 and *I/M/O the Review and Investigation of New Jersey's Electric Utilities' System Reliability,* Dkt. No. EX99100763. In the record of the instant base rate case, the Ratepayer Advocate raised a number of concerns pertaining to service quality and reliability and made a series of proposals, including the establishment of performance standards. The Board itself has taken measures to increase service quality and reliability in JCP&L's service territory -- for instance, an investigation is being performed on JCP&L's storm response in August 2002, *I/M/O Jersey Central Power and Light Company Storm Restoration Effort for the August 2, 2002 Outages,* Dkt. No. EX02120950 dated March 13, 2003.

In addition, as a result of the recent outage problems experienced over the July 4, 2003 weekend by JCP&L customers in the shore areas, the Board is reviewing an expedited action plan, including the appointment of a Special [*23] Reliability Master to oversee necessary reliability improvements in an expedited manner.

By Order dated July 16, 2003 in Dkt. No. EX03070503, this Board has directed the Company to take immediate action to address the problems it has experienced this summer. The Board further believes, however, that, as part of its decision in this case, it is appropriate that additional measures be taken to improve JCP&L's system-wide reliability. The Board therefore ORDERS a Phase II proceeding to review whether the Company is in compliance with current requirements and standards and to establish additional performance standards for JCP&L, which should include specified targets to improve JCP&L's reliability and service quality in the shore area, on both a short-term and longterm basis, as well as to improve service quality and reliability throughout JCP&L's entire service territory. Such improvements must be undertaken immediately by the Company in the most expedited and efficient manner. It is anticipated that the results of the current ongoing reviews and focused audits, including the review of the Special Reliability Master, will be merged with the Phase II proceeding.

The Board HEREBY [*24] APPROVES Staff's recommendation that the Company be ordered to segregate on its books all capital expenditures related to improvements of its system. Any such expenditures and projects undertaken by JCP&L to increase its system's reliability will be reviewed as part of the Phase II proceeding, to determine their prudency and reasonableness for rate recovery.

4. Rate of Return

There was a range in the record in this case for return on equity, with 12% requested by the Company, 9.75% recommended by Board Staff, and 9.5 % recommended by the RPA (with an additional 35 basis point adjustment to reflect an adjustment to the capital structure). Based on its review of the record, the Board HEREBY REJECTS the Company's proposal as unreasonable and FINDS that the positions of the RPA and the Staff represent a more appropriate range of reasonableness for return on equity, in light of current economic conditions. Moreover, in light of the service problems documented in the record, and in light of JCP&L's continuing problems in maintaining safe, adequate and proper service, and pending the Board's Phase II proceeding described above, the Board HEREBY ORDERS that the appropriate [*25] return on equity for JCP&L's shareholders be set at the low end of that range, 9.50%, which is the rate that had been recommended by the Ratepayer Advocate in the base rate case and is the lowest return on equity recommended in this proceeding. The Board ORDERS that this 9.5% return on equity be put into effect on an interim basis, and be reviewed as part of the Phase II proceeding. In the event that JCP&L can demonstrate that it has indeed improved its service quality and reliability, the Board will consider prospectively increasing the return on equity up to 9.75%, similar to the rate or return on equity that it has recently awarded the State's three other electric utilities. However, if as a result of the ongoing and Phase II investigations, it becomes apparent that current reliability standards and requirements have not been met, the Board reserves its rights to take further appropriate actions, including, but not limited to, reducing the return on equity to as low as 9.25%, from the date of this Order.

As a result of the First Energy merger and the purchase accounting associated therewith (and net of the write-off of $ 300 million of the Company's MTC/BGS deferred balance [*26] also associated with the merger), the Company's common equity ratio as of the end of the test year was 68.0%. After eliminating both adjustments for ratemaking purposes, as proposed by the Company in its Briefs, the ratio is reduced to 57.2%. Moreover, the proposed Settlement provides for a further reduction, to 54%. However, the Board views even that ratio to be excessive for an electric distribution company for the reasons set forth in Staff's Briefs in support of its recommended rate of return. Accordingly, the Board ACCEPTS Staff's proposed capital structure (a 46% common equity ratio) as being more representative and appropriate for an electric distribution company on a going forward basis.

After reflecting the 9.50% rate of return on common equity and Staff's recommended capital structure, the Board HEREBY DETERMINES that the Company's overall rate of return shall be 8.38%.

B. Deferred Balances Case

The Company's proposed Settlement, which was submitted to and adopted by the ALJ, proposes that, on an interim basis pending the Board's decision on the Company's securitization petition, the Company's MTC/BGS deferred balance be recovered at the rate of $ 67.0 [*27] million per year, exclusive of the 6% New Jersey Sales and Use Tax ("SUT"). This is based on the Company's most recent projection n1 of its MTC/BGS deferred balance ($ 618.0 million, as of July 31, 2003, the end of the four-year transition period approved by the Board for implementing the rate reductions, retail choice and other provisions of the EDECA), a 10-year amortization, an interest rate of 1.50%, no disallowances, and no deduction of accumulated deferred income taxes from the recoverable balance. In view of the disallowances recommended by the Auditors, Board Staff and the Ratepayer Advocate, as briefly summarized below, and the record evidence supporting these disallowances, the Board REJECTS the Company's position on this issue.

n1 The proposed Settlement indicates that the $ 618.0 million projection is based on actual data through March 2003. While the Company's most recent deferred balance report filed with the Board (by letter dated June 30, 2003) reflects actual data through May 2003, the balance projected as of July 31, 2003 remains unchanged at $ 618.0 million, including accrued interest of $ 40.7 million.

[*28]

Based on a review of the Company's BGS procurement during the first three years of the transition period (the three years ended July 31, 2002), the recommended disallowances range from approximately $ 17 million to nearly $ 300 million:

($ Millions)

	Auditors	RPA	Staff
BGS procurement	$ 11.7	$ 239.0	$ 152.5
NUGcosts	5.6	59.5	0
Total	$ 17.3	$ 298.5	$ 152.5

The BGS disallowance proposed by the Auditors (Barrington-Wellesley Group, Inc, who examined the prudency of the Company's BGS procurement n2) was based on an analysis of the Company's forward purchases for the months of June, July and August 2001, during which the Company was found to have deviated from its "fill strategy," that is, it assertedly failed to obtain the percentage of its BGS requirements it had planned to meet with forward contracts in these months. The Auditors' proposed disallowance of non-utility generator ("NUG") costs was based on the Company's alleged failure to aggressively mitigate the above-market costs of its power purchase agreements ("PPAs") with three relatively small NUG projects, Camden, Gloucester and Kenilworth, aggregating 50 Mw. In quantifying the NUG disallowance,

Tab I

DT 01-221

KEARSARGE TELEPHONE COMPANY

Petition for Approval of Alternative Form of Regulation

Order Following Hearings

O R D E R N O. 24,281

February 20, 2004

APPEARANCES: Murray, Plumb & Murray by John C. Lightbody, Esq. for Kearsarge Telephone Company; Office of Consumer Advocate by F. Anne Ross, Esq. on behalf of residential ratepayers; and Donald M. Kreis, Esq. of the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY

On November 9, 2001, Kearsarge Telephone Company (KTC) filed with the New Hampshire Public Utilities Commission (Commission) a petition for an alternative form of regulation pursuant to RSA 374:3-a. This statute provides that, upon petition or on its own motion, the Commission may "approve alternative forms of regulation other than the traditional methods which are based upon cost of service, rate base and rate of return" as long as the alternative regulation yields "just and reasonable rates and provides the utility the opportunity to realize a reasonable return on its investment." KTC, a subsidiary of TDS Telecom, Inc. (TDS), is an incumbent local exchange carrier that provides service to customers in Boscawen, Chichester, Meriden, New London, Salisbury, Webster and Wilmot.

A. Rate Issues

As noted by the parties at hearing, there are only three contested issues in connection with KTC's rate case filing. In all other respects, the parties and Staff are in agreement that the Commission should adopt KTC's proposal. The issues in dispute concern (1) recovery by KTC of expenses associated with bad debts owed to KTC by two toll carriers, WorldCom and Global Crossing, both of whom have sought bankruptcy protection, (2) whether the Commission should impute to KTC a capital structure of 50 percent debt and 50 percent equity, as opposed to the Company's actual capital structure of 15 percent debt and 85 percent equity, and (3) whether the 15.09 percent cost of equity reflected in KTC's rate filing is reasonable.

1. Kearsarge Telephone Company

KTC noted that, at the time of the Global Crossing and WorldCom bankruptcy filings, the two interexchange companies (IXCs) owed a total of $102,045 to KTC. According to KTC, these bad debts reflected known and measurable changes to the Company's test year revenues and therefore should be included as adjustments to such revenues. KTC contended this is so because (1) these bad debts represent a new type of business risk not previously faced by independent telephone companies like KTC, (2) the amounts involved are more than ten times KTC's average bad debt for the past four years, and (3) the bad debt otherwise included in KTC's test year consists of funds owed by retail customers, as opposed to IXCs.

In KTC's view, the Commission can and should recognize this new business risk for ratemaking purposes by either (1) adding a normalized amount to KTC's revenue requirement, (2) imposing a temporary surcharge on KTC's intrastate access rates to allow recovery of this amount, or (3) reducing any refund from KTC's overearnings (based on the previously established temporary rates) by the amount of the loss. With respect to normalization, KTC urged the addition of $34,015 (one-third of the debts in question) to the revenue requirement to reflect a determination that these types of problems are likely to arise once every three years for major telephone carriers.

KTC disagreed with OCA's suggestion that the Company should have protected itself against these losses, noting that the debts were current (and thus not subject to disconnection or other collection-related remedies) at the time of the bankruptcy filings. KTC further posited that any future recovery of these debts could be refunded to customers without precluding the adjustment the Company proposes now. Finally, KTC argued that if the Commission finds that KTC is overearning, intrastate access rates (as opposed to its local rates) should be reduced. If the Commission determines access rates should be reduced and temporary rates should be refunded to Interexchange Carriers (IXCs), KTC recommends the amount of the refund be offset by the amount of bad debt. This, according to KTC, is an equitable solution because the IXCs will be paying for the additional expense caused by changes in the IXC competitive market and the failure of two IXCs.

KTC urged the Commission to employ the Company's actual capital structure (85 percent equity and 15 percent debt) in determining the cost of capital to be applied to rates. According to KTC, an appropriate capital structure is an area of management discretion that should be left to each telephone utility in determining how to utilize its resources to provide quality, reliable service. It is KTC's contention that a key exercise of that discretion here involves maintenance of an A minus credit rating. KTC conceded it is a relatively small portion of the TDS corporate family and will, therefore, have little effect on the overall TDS credit rating. KTC nevertheless suggested that imputing a hypothetical capital structure would be tantamount to regulating the Company on the assumption that other jurisdictions will allow other TDS affiliates to employ their actual capital structures.

In the alternative, KTC contends that if the Commission decides to impute a capital structure to the Company, a figure of 75 percent should be used for equity. According to

KTC, this is the average equity position of New Hampshire independent telephone companies other than KTC. Further, according to KTC, any decision to impute a capital structure to KTC should be applied prospectively only. In KTC's view, such a decision would amount to a major policy change and, thus, it would be unfair to make such a change retroactive to March 1, 2002 (the effective date of the temporary rates in this docket). KTC suggested setting a revenue requirement for an initial three-year period based on the current capital structure, to allow the Company to transition to the capital structure desired by the Commission.

Finally, KTC argued that if the Company is required to shift any of its present equity to debt, the additional debt should bear the Company's current cost of borrowing (a minimum of 7.5 percent), as opposed to KTC's historic cost of borrowing (averaging 6.2 percent). Assuming KTC's actual capital structure is used, KTC argued that its actual cost of debt from existing issues should be utilized for long term debt. Exh. KTC-2 p. 10.

With respect to return on equity, KTC urged the Commission to adopt 15.09 percent. According to KTC, this figure is derived from the use of the standard Discounted Cash Flow (DCF) analysis employing a proxy group of five comparable companies. KTC further maintained that it should be allowed issuance costs, there should be an adjustment to reflect overstatement of observed stock prices because of approaching dividend payments (the so-called ex-dividend adjustment) and the Commission should reject the DCF analysis of Staff witness Chris Schlegel as inconsistent with precedent.

With respect to Mr. Schlegel's DCF analysis, KTC contended that (1) the use of historical weighting in the DCF analysis is inappropriate because historical data is already reflected in the ValueLine data that forms the model's inputs, (2) Mr. Schlegel's dividend growth projections do not take into account the effect that telephone companies are presently retaining more of their earnings to improve their financial positions, (3) Mr. Schlegel should not have used a three-stage DCF model, (4) Mr. Schlegel incorrectly contends that KTC's return on equity should be low because interest rates are generally low throughout the economy, and (5) that even assuming Mr. Schlegel's methodologies are correct they should result in a return on equity of 13.20 percent. KTC further pointed out that in Docket No. DT 02-110, which concerns the cost of capital of Verizon New Hampshire, the OCA's expert witness made several recommendations that KTC contends conflict with Mr. Schlegel's recommendations here.

KTC requested that the Commission defer its decision on rates to its consideration of all issues in this case.

According to KTC, this would maximize the Commission's flexibility with respect to designing an appropriate alternative regulation plan for the Company. According to KTC, deferring a decision on rates would not harm ratepayers because they are adequately protected by temporary rates which will be reconciled in the event the Commission determines the Company has been over-earning.

2. Office of Consumer Advocate

OCA contended that KTC's receivables arising out of the Global Crossing and WorldCom bankruptcy proceedings should not be treated as bad debts or trigger any adjustment to test-year revenues. According to OCA, two facts emerged at the hearings in May that are relevant: the fact that KTC had been negotiating a settlement of its claims against the two bankruptcy debtors and the fact that KTC has accounts payable that it owes to WorldCom that KTC is claiming as an offset against the unpaid receivables. In OCA's view, the debts in question are not currently known and measurable (given the ongoing bankruptcy proceedings and attendant corporate reorganizations, which could result in at least a partial payout of the amounts owed KTC). At the very least, according to OCA, the offset amounts disclosed at hearing should be deducted from the debt amounts.

OCA further asserted that the record does not support KTC's contention that it faces additional risk of bad debts similar to those owed by Global Crossing and WorldCom. According to OCA, only three other carriers had monthly accounts payable in excess of $25,000, and these entities are not in danger of seeking bankruptcy protection. OCA also pointed out that the test year for this case is 2001, whereas the debts in question were incurred in 2002. According to OCA, since the amount of the loss cannot be fixed with certainty, it would be inappropriate to make any adjustment to test-year revenues.

OCA supported Staff's proposal to impute a capital structure to KTC consisting of 50 percent debt and 50 percent equity. According to OCA, in *New England Telephone Co. v. State*, 98 N.H. 211 (1953), the New Hampshire Supreme Court affirmed a Commission determination that a 45-55 percent debt/equity ratio is appropriate for a telephone company, noting that the Commission can "legally determine a just and reasonable rate of return upon a capital structure different from the actual structure of the company at the time the case was adjudicated." *Id.* at 220.

OCA pointed out that Staff's recommendation with respect to imputing a capital structure to KTC does not require the Company to make actual changes to its capitalization. According to OCA, if KTC wishes over time to change its actual capital structure to conform to the structure that the Commission can and should impute here, the Company is free to do so - but it must take that action in a manner that does not disrupt or damage the utility's business or financial integrity.

OCA supported Staff's recommended 8.892 percent cost of equity, as opposed to the 15.09 percent proposed by KTC. According to OCA, the determination requires the Commission to choose among the views of the three experts who testified on the subject: Mr. Schlegel, Mr. Woltman (who provided KTC's initial recommendations) or Mr. Makholm (who critiqued Mr. Schlegel's approach and arrived at a cost of equity of 13.20 percent).

OCA invoked the Commission's plenary ratemaking powers under RSA 378:7 in suggesting that the Commission not defer consideration of rate-related issues to its determination with respect to KTC's proposed alternative regulation plan. According to OCA, the inquiries are fundamentally independent of one another and should be decided separately.

OCA disagreed with Staff's recommendation to apply any over-earnings determined here to a reduction in intrastate access charges to IXCs. According to OCA, it is more appropriate to reduce basic rates, given the lack of correlation between the intrastate access rates charged to IXCs and the intrastate long distance rates actually paid by the customers of the IXCs.

According to OCA, a mainstay of Mr. Woltman's testimony was his contention that KTC is facing increasing competition and risk. Yet, OCA contended, KTC failed to produce any evidence that it has lost even a single local customer to a land-line competitor. OCA points out that KTC has never received a request for interconnection under 47 U.S.C. § 251(f) (which would trigger Commission proceedings with respect to KTC's exemption as a rural telephone company from the obligation to interconnect with competitive telecommunications carriers) and still enjoyed an exclusive utility franchise under RSA 374:22-f. OCA noted that KTC has offered to waive its exclusive franchise as a matter of state law as a part of its alternative regulation proposal, but points out that such a plan has not yet been put into effect. OCA also noted that KTC has not demonstrated any significant line loss in its service territory over the past five to ten years.

According to OCA, given that KTC has admitted it is at a lower risk than other telecommunications utilities operating in larger urban areas, it has no basis to request a higher rate of return than the average 11.15 percent return on equity proposed by OCA's expert witnesses in the Verizon cost of capital proceeding, Docket No. DT 02-110. OCA also pointed out that KTC's requested cost of equity here is considerably higher than the 10.77 percent return on equity approved by the Commission the last time KTC litigated the issue.

3. Staff

Staff noted that KTC's current capital structure consists of 84.63 percent common equity and 15.37 percent debt. Staff witness Schlegel characterized this as unusual, noting that as of June 2002, telecommunications carriers with Moody's ratings at investment grade or higher had, on average, a capital structure consisting roughly of debt and equity in equal parts. Such a structure, according to Mr. Schlegel, is one that preserves the financial soundness of the company.

Staff proposed that the Company's reported 6.24% cost of debt should be used in calculating the Company's weighted average cost of capital. Staff pointed out that the Company continues to utilize low cost debt financing, and that therefore KTC's actual cost of debt remains in a range that is reasonable.

Mr. Schlegel noted that, because KTC is a subsidiary of a parent firm and thus not a publicly traded company, it was necessary to use a proxy group of publicly traded companies to develop an estimate of KTC's cost of equity. Staff used the same five proxy companies as KTC did, but noted that it considered these companies to have a higher degree of risk (and thus a higher cost of capital) than KTC. Thus, according to

Staff, the data from the proxy companies should produce cost-of-equity results that are conservatively high with respect to KTC.

Staff took the data from the proxy firms (current annual dividend, current stock price and growth rates) and derived a proposed cost of equity using the discounted cash flow (DCF) model. However, Mr. Schlegel proposed a modification of the traditional DCF model. According to Mr. Schlegel, the DCF model as it has applied in the past assumes that the company in question can sustain its growth rate indefinitely – which, according to Mr. Schlegel, results in the "firm being compensated for rewarding investors with growth so large that it eventually produces a telecommunications carrier equal to the size of the economy." Staff Exh. 1 at 16.

Therefore, Staff proposed the use of a "3-stage" version of the DCF model that employs the usual growth rate to estimate the discounted cash flow only for the first five years. This model posits a "Stage 3" or long-term growth rate pegged at the annual long-run sustainable growth rate of the economy's nominal output, set at 5.5 percent (the sum of real output growth of 3.5 percent and inflation of 2 percent). Under this model, "Stage 2" is simply a transitional growth rate that allows for a smooth transition from the "Stage 1" to the "Stage 3" growth rate. According to Mr. Schlegel, using the three-stage DCF model yields a cost of equity for KTC of 8.89 percent, 29 basis points higher than that which the standard DCF model would predict. According to Mr. Schlegel, this is reasonable, based on checking these results using other calculation methods (risk premium method, Ibbotson's Full Information Beta method and general market observations). This yields a weighted average cost of capital of 7.565 percent, based on imputing a capital structure to KTC of debt and equity in equal parts.

Staff witness Mary Hart additionally proposed certain *pro forma* adjustments to the Company's revenue requirement. The Company agreed to most but not all of these adjustments. The remaining dispute involved KTC's plan to amortize $102,045 over three years to reflect uncollected access charges arising out of the Global Crossing and WorldCom bankruptcies. According to Staff, this would have the effect of improperly building $34,015 into the company's annual revenue requirement for a non-recurring expense.

B. Issues Related to the Cash Management Fund

1. Office of Consumer Advocate

OCA addressed two issues with respect to KTC's cash management fund. First, OCA contended KTC should not be permitted to include $10,124,778 of temporary investments in common equity for the purpose of calculating the Company's cost of capital. According to OCA, by accumulating these earnings, retaining them and then including them in its cost-of-capital alternative regulation plan, according to Staff, would allow reduction in infrastructure investment and quality of service and therefore is not in the public interest.

III. COMMISSION ANALYSIS

A. Rate Issues

As we have previously noted, this case is analogous to a traditional, cost-of-service ratemaking proceeding, inasmuch as we must "make a determination as to the appropriate starting point" for any alternative regulation plan. Order No. 23,925, slip op. at 6; *see also* Order No. 24,056, slip op. at 6. We are thus required to decide whether the base rates requested by KTC are "not unduly discriminatory, are just and reasonable, and provide the Company with the opportunity to earn a reasonable return on its investment." Order No. 23,925, slip op. at 6; *see also Appeal of Conservation Law Foundation*, 127 N.H. 606, 633-34 (1986) (describing traditional ratemaking process). The purpose of the inquiry is to determine rates that fall in a "zone of reasonableness between the extremes of confiscating a utility's property, at one end, and exploiting customers for the utility's benefit, at the other." *Appeal of Public Service Co. of N.H.*, 130 N.H. 748, 750-51 (1988).

As noted by KTC, the issues in dispute along the road to just and reasonable rates are very few. We address each in turn.

1. Bad debts

The first issue concerns bad debts arising out of the Global Crossing and WorldCom bankruptcy filings, given that KTC is a creditor of both. According to KTC, these bad debts comprise a new type of business risk that generate known and measurable changes to KTC's test-year revenue. KTC proposes that we add $34,015 to the Company's revenue requirement, reflecting one third of the debts in question. In the alternative, KTC proposes a temporary surcharge on the Company's intrastate access rates to allow recovery of the debts or, similarly, a reduction in any refund arising out of KTC's over-earnings.

We are unable to agree with the premise that the bad debts are known and measurable expenses that should generate adjustments to test-year revenue. The record does not reflect that expenses of this type are recurring, despite KTC's assertion that this type of bad debt represents a new and persistent business risk for independent telephone companies. Thus, as the Commission stated in *Concord Steam Co.*, 71 NH PUC 667, 683 (1986), "unless such expenses are excluded, ratepayers will be required to pay such expenses on an annual basis in spite of the fact that they are no longer being incurred by the Company." As pointed out by the OCA, the record reflects that efforts to collect these debts by KTC were ongoing, and KTC was claiming certain accounts payable as an offset against these bad debts. The letter received on January 23, 2004, from Attorney Lightbody, indicates that in December 2003, the Company recovered approximately 48 percent of the bad debt owed by WorldCom, through settlement. As to the claim against Global Crossing, the letter reports that a settlement was reached but payment of the settlement was conditioned on Global Crossing's emergence from bankruptcy and Global Crossing's continued financial ability to make payment following its emergence from bankruptcy. In the case of Global Crossing, the ultimate amount of bad debt is not known and measurable. Further, there is no evidence on the record that the expense will be a recurring one so as to be appropriate for inclusion in the Company's revenue requirement. Finally, KTC's ongoing efforts to collect the debts are themselves reflective of the reality that the ratemaking process is not designed to insulate utilities from the need to engage in such activities when appropriate.

Accordingly, we will not include an adjustment for bad debt of this nature in the revenue requirement. However, because we have determined infra that KTC should refund its temporary rates overcollection to IXC customers, we will allow KTC to reduce the amount of the refund of temporary rates by $61,995, the net amount of known and measureable bad debt reported in the letter received on January 23, 2004. We find this treatment equitable because it assigns a cost associated with the IXC market to an IXC rate rather than to retail rates.

2. Capital Structure

We next turn to the question of what rate of return to apply to KTC. "[T]he rate of return is a percentage applied to the rate base expressed as a dollar amount in order to produce interest on long-term debt, dividends on preferred stock, and earnings on common stock (including surplus or retained earnings)." *Conservation Law Foundation*, 127 N.H. at 635 (citation and internal quotation marks omitted). Contrary to the suggestion of KTC, "[t]he actual needs of the company do not control what the commission may do when it sets the rate of return." *Id.* at 635-36. The Commission may set the rate of return "by reference to a capital structure that [the Commission] finds appropriate, rather than the actual capital structure of the company." *Id.* at 636. This is because "the object of the process is to strike a fair balance between recognizing the interests of the customer and those of the investor . . . rather than necessarily to guarantee . . . stockholders their dividends." *Id.*

The New Hampshire Supreme Court has stressed the role that judgment plays in setting a rate of return. *Id.* at 636. The Court has also stated that in striking a fair balance between the interests of the ratepayer and the shareholder as required by *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591 (1944) and *Bluefield Water Works v. West Virginia Public Service Commission* 262 U.S. 679, 675 (1923), the Commission may impute a capital structure that it finds to be appropriate, rather than using the Company's actual capital structure. *Id.* In subsequent cases we have explicitly relied upon this principle, recognizing that "commissions are entitled to 'make the pragmatic adjustments which may be called for by particular circumstances,'" *Kearsarge Telephone Company*, 73 NH PUC 320, 326 (1988) (citing *Federal Power Commission v. Natural Gas Pipeline Co.*, 315 U.S 575, 586 (1942)), and must "exercise … a 'fair and enlightened judgment, having regard to all relevant facts,'" *id.* (citations omitted). In this instance, determining the allowable rate of return based on the utility's actual capital structure (84.63 percent common equity and 15.37 percent debt) would not strike a fair balance between the ratepayer and shareholder. Rather, it would tend to favor KTC's investors too heavily, given that KTC's total cost of long term debt is historically 6.24 percent and, based on any methodology we might reasonably apply here, KTC's cost of equity will be in excess of that figure.

Staff witness Schlegel testified that telecommunications carriers with Moody's ratings at investment grade (Baa) or higher have, on average, capital structures consisting of debt and equity in equal parts. Staff therefore reasons that imputing such a capital structure to KTC is reasonable because it (1) reduces KTC's overall cost of capital to a more balanced figure, and (2) increases the leverage of the Company, and therefore its risk, but only to a level that does not threaten the utility's financial soundness.

This testimony is essentially unrebutted. A KTC witness, Mr. Woltman, testified that it is the policy of KTC's parent company to require KTC to maintain a credit rating of A-, which, according to Mr. Woltman, requires a capital structure that is at least 75 percent equity.

Because KTC is not separately traded we must use a hypothetical capital structure. As we did in our recent order establishing a new cost of capital for Verizon, we will look to what a reasonable and prudent manager would choose for a capital structure. *See Verizon New Hampshire*, Order No. 24,265 (Jan. 4, 2004), slip op. at 50.

KTC correctly points out that the actual capital structure employed by this or any other utility is a matter of discretion that is properly left to management. This argument, and similar statements in Mr. Woltman's testimony, imply that by imputing a capital structure to KTC we would, in effect, be substituting our judgment for management's. This is incorrect

KTC remains free to operate with whatever capital structure its owners and managers deem prudent.[1] The determination we make here, entirely consistent with established precedent, is that ratepayers cannot be expected to subsidize a strategy that unduly favors stockholders. As we stated in the *Verizon* order, excess equity creates a capital structure that is too rich, and accumulating excess equity means the utility is failing to take advantage of opportunities to raise lower-cost debt funding. Id. at 50-51. We believe that a prudent manager facing the need to raise capital in today's market would place greater emphasis on debt than KTC acknowledges. Accordingly, we adopt Staff's view that the financial soundness of KTC would likely be preserved under a capital structure where debt and equity are equal and we will therefore impute such a capital structure to the Company for ratemaking purposes in this case.

3. Cost of Debt

KTC asserted that if the Commission were to impute a capital structure, that it would be unreasonable for the Commission to apply the utility's historic cost of debt, 6.24 percent, to the rate calculation when the evidence suggests that KTC's current cost of borrowing is at least 7.5 percent.

[1] For this reason, we are unpersuaded by KTC's suggestions that we (1) apply any imputed capital structure prospectively after a reasonable transition period, or (2) do not apply any imputed capital structure in the process of reconciling permanent to temporary rates.

However, as Staff pointed out at the hearing, the average long term cost of debt for maturities of 10 years and above observed for the five proxy telecommunications companies used by both Staff and the Company was 5.5 percent, significantly below the rate the Company claims is necessary to attract long term debt. Tr. 2/21/03 at 84. We therefore find that the 6.24 percent cost of debt, as reported by KTC on its books, meets the Company's financing needs and is reasonable in light of current debt market conditions.

4. Cost of equity

KTC requests that its cost of equity be fixed for ratemaking purposes at 15.07 percent. The utility makes a variety of arguments in support of that figure, which we address in the order presented in KTC's brief.

First, KTC contends that it is entitled to 31 basis points to reflect issuance costs and offers the testimony of KTC witness Makholm in support of this position. Mr. Makholm stated that in "many different regulatory jurisdictions" the practice of adding an increment to the allowed cost of equity to reflect issuance expenses is the "traditional way". Tr. 2/21/03 at 104.

We are unpersuaded. KTC cites no case, and we are aware of no contested case, in which this Commission has ever increased its calculation of a utility's cost of equity to reflect issuance expenses. We recently reiterated our longstanding view that in the absence of any evidence of actual or planned issuances, such costs should not be compensated. *Verizon*, Order No. 24,265, slip op. at 69, citing *Pennichuck Water Works*, 70 NH PUC 850, 863 (1985). In our view, these transaction costs are already reflected in the relevant stock price.

The next issue raised by KTC concerns a so-called ex-dividend adjustment of six basis points. According to KTC, this corrects for a slight inaccuracy generated by employing the Discounted Cash Flow (DCF) model to arrive at a cost of equity.[2] As discussed, *infra*, although there is disagreement on the precise DCF methodology to be used in this case, all parties and Staff agree that DCF itself is appropriate here. Mr. Makholm testified, and KTC argues, that the DCF model fails to take into account the real-world increases in a company's stock price as the ex-dividend date (i.e., the date on which a stock must be owned if the owner is to receive an upcoming quarterly dividend

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[2] The DCF model assumes

> that the price at which an investor purchases stock is based on [the investor's] expectations as to the future yield in terms of dividends and sales price of the stock. By discounting the (expected) future yields at a rate which equalizes the present value of the future yields and the market price of the stock, the method arrives at a rate of return that the hypothetical investor is demanding on the given common stock issue. Calculation of this rate can also be obtained by adding the current dividend yield to the expected rate growth in dividends.

Boston Gas Co. v. Department of Pub. Utils., 269 N.E.2d 248, 255 (Mass. 1971).

payment) approaches. KTC explains that because the DCF model always uses a formula that places the relevant stock price in the denominator, the ex-dividend effect would tend to reduce the allowed Return on Equity unless corrected. Mr. Makholm recommends an adjustment of 6 basis points.

We find that the cost of equity must be viewed from the investor's perspective, that is, the rate of return on equity an investor requires in order to accept an equity stake in the company. By the company's reasoning, the share price increases just before dividends are paid, and decreases thereafter as the next dividend payment is one quarter into the future. However, the investor accepts a higher share price - and therefore a slightly lower return - knowing that the cash dividend will be paid out shortly. This is evidenced by the fact that investors do not sell the shares of the proxy companies in droves as the dividend date approaches. No additional return on equity is therefore required as investors are willing to hold the shares at the going price. If it were, investors would be quick to have the share price reflect this fact. We are thus not persuaded that the company's adjustment is necessary.

The next assertion of KTC is that we should reject the precise DCF formula employed by Staff witness Schlegel because it is inconsistent with methods used by Staff analysts in previous cases. Specifically, KTC challenges Mr. Schlegel's use of "least squares" methodology, his reduction in weighting of earnings (as opposed to dividends) to 25 percent as compared to previous cases in which earnings were weighted at 37.5 percent, his weighting of historic data at 66.7 percent and ValueLine data at 33.3 percent where Staff had previously used only ValueLine data, and Mr. Schlegel's use of a three-stage version of the DCF model where the Commission has previously employed a one-stage version of the model.

We are aware of no legal principle, and KTC cites none, that requires a specific application of the DCF in our analytical approach to fixing a utility's allowed cost of equity. The test is whether the methodology employed causes the cost of equity to fall within a "zone of reasonableness." *Public Service Co. of N.H.*, 127 N.H. at 634-35 (stressing, generally, the Commission's "discretion in setting each of [the] variables" in the traditional ratemaking formula); *see also Appeal of Manchester Gas Co.*, 129 N.H. 800, 806(1987) (holding that the Commission is free to depart from previous policy so long as the departure has a "reasonable basis").

We begin with KTC's last concern - use of the three-stage DCF analysis. The issue is what rate of expected growth in earnings and dividends to apply in calculating the present value of the future cash flows associated with KTC's stock.[3] According to Mr. Schlegel, a one-stage DCF model assumes that the company's growth rate "can apply indefinitely." Staff Exh. 1 at 15-16. According to Mr. Schlegel, in such circumstances "the cost of equity would be too high, as the firm is being compensated for rewarding investors with growth so large that it eventually produces a telecommunications carrier equal to the size of the economy." *Id.* at 16.

The alternative proposed by Mr. Schlegel involves applying the ValueLine projection of the utility's growth rate for an initial period of five years, as opposed to indefinitely. This is Stage 1. At Stage 3, Mr. Schlegel would apply "the annual long run sustainable growth rate of the economy's nominal output," which he sets at 5.5 percent (comprised of real output growth of 3.5 percent and inflation of 2 percent). *Id.* at 16-17. Stage 2 simply "allows for a smooth convergence of the short run growth rate toward the long run." *Id.* at 17. According to Mr. Schlegel, use of the three-stage model yields a cost of equity that is 29 basis points higher than that derived from a one-stage model.

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[3] In considering the discussion that follows, it is useful to keep in mind that KTC stock is not traded on any market because it is a wholly owned subsidiary of a parent company. Thus, Mr. Schlegel estimated KTC's cost of equity by using figures from five publicly traded "proxy" companies that he believes are reasonably similar to KTC. See Staff Exh. 1 at 14. KTC's witnesses explicitly agreed with the proxy firms used by Mr. Schlegel.

In response, KTC witness Makholm concedes that "there is nothing inherently wrong" with a multi-stage DCF model. KTC Exh. 7 at 8. However, he contends that "the multi-stage DCF model is not likely to be useful in rate proceedings because reliable and appropriate data to implement the model is not available." *Id.* Specifically, Mr. Makholm questions both the Stage 1 and Stage 3 growth rates applied by Mr. Schlegel.

According to Mr. Makholm, Mr. Schlegel's estimate of the long-term growth rate (applicable at Stage 3) is appropriate for use in other contexts, but is inappropriate here because the DCF model measures investor expectations and "there is no evidence from financial markets to support Mr. Schlegel's assumption that investors believe that individual companies' growth rates begin to revert to an economy-wide mean after five years." *Id.* at 9-10. Mr. Makholm also argues that a single economy-wide growth rate would never be applicable to high-yield companies (such as gas utilities) and their low-yield counterparts in the telecommunications industry.

With regard to the short-term growth rate applied by Mr. Schlegel at Stage 1, which Mr. Makholm describes as a weighted average of historical and forecast dividend and earnings growth rates, Mr. Makholm's contention is that (1) the assumed dividend growth rates "are affected by past and projected trends in payout ratios, making them specifically inapplicable proxies for prospective growth," and (2) the assumed earnings growth rates "show the traditional problems associated with the use of such figures for DCF analyses." *Id.* at 10. Noting that dividend payout ratios have been consistently declining in the telecommunications industry, Mr. Makholm proposes the use of only projected earnings growth rates. Apparently overlooking his own critique of the use of assumed earnings growth rates, he suggests that these projections be used exclusively, and applied in a single-stage DCF model to yield a "minimum estimate" of KTC's cost of equity (including the adjustments for issuance costs and the ex-dividend problem) of 13.20 percent, as opposed to Mr. Schlegel's estimate of 8.892 percent (which does not include those adjustments).

In rebuttal, Mr. Schlegel stresses the "underlying economic logic" of his DCF calculations, disputing that it reflects only the analyses of professional economists as opposed to the expectations of investors. *See* Tr. 2/21/03 at 208. He testified that the formula he applied did not come from any academic work but, rather, from a guide created for investment analysts. *Id.* He noted that, as a check of his calculations, he derived a cost of equity for KTC by using another methodology (the capital asset pricing model (CAPM)), yielding a rate that is below 9 percent. *Id., see also* Staff Exh. 1 at 17-19 (describing Mr. Schlegel's use of Ibbotson's Full Information

Beta method as a check of his DCF analysis, yielding a cost of equity of 8.56 percent). With regard to the suggestion of disregarding dividend growth projections, Mr. Schlegel stated that in such an instance one would "no longer [be] talking about a discounted cash flow, because the cash flows that we're discounting are the cash flows that the investor receives, not the cash flow that the Company has." Tr. 2/21/03 at 211 (conceding that "investors are also concerned with earnings," which is why he "assigns some weight to earnings, but not 100 percent").

In considering the contrasting views of these two economists, we begin by noting a significant development that post-dates KTC's suggestion that we have never departed from the one-stage version of the DCF model. We did just that, and endorsed the three-stage version, in our recent *Verizon* decision. *See Verizon*, Order No. 24,265, slip op. at 65 (noting that the three-stage version of the DCF comprises "refinement" and "improvement" over the one-stage version). The arguments and expert opinions presented here do not persuade us to deviate from the analysis we applied in the recent *Verizon* cost-of-capital proceeding. Essentially, we do not agree with Mr. Makholm that Mr. Schlegel's model, which takes reality into account over the long term, is inapposite because investors do not allow the long-term limits of the economy to color their investment decisions. We agree with Mr. Schlegel that it would be inappropriate to abandon any use of dividend projections, for the reasons stated by him at hearing. And, like Mr. Schlegel, we draw comfort from the knowledge that checks using other methodologies produce results that are close to those derived by him using the three-stage DCF formula.

In sum, we adopt Mr. Schlegel's methodology, and find 8.89 percent a reasonable estimate of KTC's cost of equity.

5. Rate case expenses

In his pre-filed testimony, KTC witness Woltman estimates that the utility will have incurred $158,000 in recoverable rate-case expenses. He recommended that these costs be amortized over three years and that KTC's intrastate revenue requirement be adjusted accordingly. OCA counters that it is likely a good portion of these expenses are not recoverable because they are associated with KTC's petition for approval of an alternative form of regulation. According to OCA, a detailed audit is required.

To the extent that KTC is suggesting that we should resolve any rate-case expense issues now, and to the extent that the OCA is recommending that we adopt our usual practice of deferring this issue to after the case is decided on its merits and after Staff has had an opportunity to conduct a careful review of the claimed expenses, we agree with the OCA.

Tab J

2003 Colo. PUC LEXIS 1428

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PHILLIPS COUNTY TELEPHONE COMPANY WITH ADVICE LETTER NO. 61

Decision No. R03-1466; DOCKET NO. 03S-315T

Colorado Public Utilities Commission

2003 Colo. PUC LEXIS 1428

December 31, 2003, Mailed

CORE TERMS: tariff, settlement agreement, notice, sheet, capital structure, funding, cooperative, switched, pro forma, settlement, revised, calculation, effective date, recommended, intrastate, public interest, suspended, effective, weighted, annually, rate of return, modification, methodology, patronage, updated, percent figure, recommendations, direct testimony, total amount, hand-delivered

OPINION:

RECOMMENDED DECISION OF ADMINISTRATIVE LAW JUDGE DALE E. ISLEY GRANTING JOINT MOTION TO APPROVE STIPULATION AND SETTLEMENT AGREEMENT

I. STATEMENT

1. The captioned proceeding was commenced on June 30, 2003, when Phillips County Telephone Company (PCTC) filed Advice Letter No. 61, with accompanying tariff sheets. The stated purpose of this filing was to increase PCTC's intrastate access rates by approximately 34 percent. In addition to these tariff changes, PCTC requested support from the Colorado High Cost Support Mechanism (HCSM) in the total amount of $ 22,387 pursuant to the Commission's Rules Prescribing the Procedures for Administering the Colorado High Cost Fund, 4 *Code of Colorado Regulations* (CCR) 723-41.

2. By Decision No. C03-0806 adopted on July 23, 2003, the Commission suspended the effective date of the tariffs filed by PCTC with Advice Letter No. 61 for a period of 120 days and assigned this matter to the undersigned administrative law judge (ALJ). By Decision No. C03-1312 dated November 24, 2003, the Commission suspended the effective date of the subject tariffs for an additional 90 days.

3. Timely interventions were filed in this matter by the Staff of the Colorado Public Utilities Commission (Staff) and the Colorado Office of Consumer Counsel (OCC).

4. On September 22, 2003, PCTC filed the direct testimony and exhibits of Kevin J. Kelly, a Managing Regulatory Consultant for TCA, Inc.--Telecom Consulting Associates. Answer testimony and exhibits were submitted by John P. Trogonoski and Karlton R. Kunzie, Staff Rate/Financial Analysts, and Patricia Parker, an OCC Rate Analyst, on November 3, 2003. On November 13, 2003, PCTC submitted rebuttal testimony and exhibits from Mr. Kelly, James B. Dean, an attorney with Dean & Stern, LLC, and Dr. James H. Vander Weide, President of Financial Strategy Associates.

5. This proceeding was originally set for hearing on November 21, 2003. *See,* Decision No. C03-0806. That decision also established a procedural schedule governing this case. However, on November 19, 2003, PCTC filed a Motion to Vacate Procedural Schedule (Motion to Vacate) advising that the parties had reached a tentative settlement resolving all disputed issues in this matter. The Motion to Vacate was granted on November 24, 2003. *See,* Decision No. R03-1313-I. That decision established December 10, 2003, as the deadline for submission of a settlement agreement. It also set a December 18, 2003, hearing date in the event a hearing was required in connection with any such agreement.

6. On December 10, 2003, PCTC, Staff and the OCC filed a Joint Motion to Approve Stipulation and Settlement Agreement (Motion to Approve Stipulation). A Stipulation and Settlement Agreement (Stipulation) signed by the parties was filed contemporaneously with these pleadings. On December 19, 2003, PCTC filed a Notice of Supplemental Filing

(Supplemental Filing) that included revised *pro forma* tariffs (referred to as Exhibit A in the Stipulation) that were inadvertently omitted from the Stipulation as originally filed.

7. On December 16, 2003, the ALJ advised the parties electronically that the Motion to Approve Stipulation would be granted and that the December 18, 2003, hearing in connection with the Stipulation would not be necessary.

II. FINDINGS AND CONCLUSIONS

8. In this proceeding PCTC seeks Commission approval to increase its intrastate access rates by $ 70,335 and to secure HCSM support in the total amount of $ 22,387. This is designed to partially offset a calculated intrastate revenue requirement deficiency of $ 165,996. The methodology utilized by PCTC in support of its proposed access rate increase is described in Schedules 1 through 7 attached to Mr. Kelly's direct testimony. The methodology utilized by PCTC in support of its request for HCSM support is described in Schedules 8 through 10 attached to that testimony.

9. Staff and the OCC challenged various aspects of PCTC's proposal. Among other things, Staff recommended a capital structure of 60 percent equity and 40 percent debt versus the 70 percent/30 percent capital structure used by PCTC; a cost of debt of 5.5 percent versus the 8.12 percent figure used by PCTC; a cost of equity of 5.75 percent versus the 12 percent figure used by PCTC; and a weighted cost of capital of 5.65 percent versus the 10.84 percent figure used by PCTC. *See,* answer testimony of Mr. Trogonoski. Staff concluded that PCTC's intrastate access rates should be allowed to increase by $ 28,842 and that it is eligible to receive $ 22,147 annually in HCSM funding. However, Staff also concluded that certain cost adjustments were required to PCTC's Separations Study, the effect of which was to lower its revenue requirement to a level that would make it ineligible for HCSM funding under § 40-15-208(2)(a), C.R.S. *See,* answer testimony and exhibits of Mr. Kunzie.

10. The OCC concluded that PCTC is not eligible for HCSM support under § 40-15-208(2)(a), C.R.S., since, under its calculations, PCTC's local exchange service revenues exceed the cost of providing local exchange services. It also concluded that PCTC's cost of service calculations were in error since, in its opinion, PCTC's regulated services are subsidizing some of its deregulated services. The OCC largely agreed with Staff's conclusions regarding PCTC's cost of equity and cost of debt. It recommended a capital structure of 50 percent equity and 50 percent debt. Using Mr. Trogonoski's cost of equity analysis, the OCC concluded that PCTC's intrastate access rates should be calculated in accordance with its revised revenue requirement recommendations. *See,* answer testimony of Ms. Parker and Exhibit PAP-13 attached thereto.

11. The Stipulation reflects the parties' compromise pertaining to the issues described above. For purposes of settlement, the parties agree that PCTC's imputed capital structure is a 40/60 debt to equity ratio, that its return on equity is 9.5 percent, that its weighted cost of capital is 7.9 percent, and that its revenue requirement is $ 1,028,725. The parties agree that the stipulated rate of return falls within a range of reasonableness. n1 They also agree that PCTC has provided proper support pursuant to 4 CCR 723-41-18.1 and 4 CCR 723-41-18.2 for HCSM funding for high loop costs and high local switching costs in the amount of $ 260 annually. Finally, they agree that PCTC's switched access rates should be increased by $ 85,545. This is to be accomplished by the filing of an Amended Advice Letter No. 61 with updated tariff sheets, updated access rates, and with a new effective date in the form of a compliance filing to be filed on one day's notice. *See,* Exhibit A attached to the Supplemental Filing.

n1 Staff's willingness to compromise on this issue results from some uncertainty as to the manner in which cooperatives such as PCTC are required to account for patronage capital under a recent pronouncement by the Financial Accounting Standards Board (FAS 150).

12. Having considered the Stipulation, as well as the pre-filed testimony and exhibits submitted in this matter, it is recommended that the Commission approve the Stipulation as filed without modification. The Stipulation is just and reasonable, is in the public interest, and should be accepted.

13. In accordance with § 40-6-109, C.R.S., it is recommended that the Commission enter the following order.

III. ORDER

A. The Commission Orders That:

1. The Joint Motion to Approve Stipulation and Settlement Agreement filed on December 10, 2003, is granted, consistent with the terms of this Order.

2. The Stipulation and Settlement Agreement filed on December 10, 2003, is accepted and approved without modification. The Stipulation and Settlement Agreement and the Notice of Supplemental Filing, copies of which are attached hereto as Appendix A, are incorporated into this Order as is fully set forth herein.

3. The parties shall comply with all terms of the Stipulation and Settlement Agreement.

4. Within ten days of the effective date of this Order, Phillips County Telephone Company shall file an advice letter citing this Decision as authority to implement, on not less than one day's notice, the switched access and special access rates set forth in the *pro forma* tariff sheets attached to the Notice of Supplemental Filing as Exhibit A.

5. The agreed increased level of annual Colorado High Cost Fund funding for Phillips County Telephone Company provided for in the Stipulation and Settlement Agreement of $ 260.00 shall become effective as of January 1, 2004.

6. This Recommended Decision shall be effective on the day it becomes the Decision of the Commission, if that is the case, and is entered as of the date above.

7. As provided by § 40-6-109, C.R.S., copies of this Recommended Decision shall be served upon the parties, who may file exceptions to it.

a) If no exceptions are filed within 20 days after service or within any extended period of time authorized, or unless the decision is stayed by the Commission upon its own motion, the recommended decision shall become the decision of the Commission and subject to the provisions of § 40-6-114, C.R.S.

b) If a party seeks to amend, modify, annul, or reverse basic findings of fact in its exceptions, that party must request and pay for a transcript to be filed, or the parties may stipulate to portions of the transcript according to the procedure stated in § 40-6-113, C.R.S. If no transcript or stipulation is filed, the Commission is bound by the facts set out by the administrative law judge and the parties cannot challenge these facts. This will limit what the Commission can review if exceptions are filed.

8. If exceptions to this Decision are filed, they shall not exceed 30 pages in length, unless the Commission for good cause shown permits this limit to be exceeded.

Appendix A

Docket No. 03S-315T

Decision No. R03-1466

December 31, 2003

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF COLORADO

RE: THE INVESTIGATION AND SUSPENSION OF TARIFF SHEETS FILED BY PHILLIPS COUNTY TELEPHONE COMPANY WITH ADVICE LETTER NO. 61.

Docket No. 03S-315T

STIPULATION AND SETTLEMENT AGREEMENT

This Stipulation and Settlement Agreement ("Agreement") is entered into by and between Phillips County Telephone Company ("PCTC"), Staff of the Public Utilities Commission ("Staff"), and the Colorado Office of Consumer Counsel ("OCC"). PCTC, Staff and OCC are referred to herein collectively as the "Parties" and individually as a "Party." This Agreement sets forth the terms and conditions by which the Parties have agreed to resolve all issues that have or could have been contested in this Docket. The Parties jointly state as follows:

Introduction

1. On June 30, 2003, PCTC filed Advice Letter No. 61 with accompanying tariffs. In its filing, PCTC sought authority, pursuant to the Commission's Rules Prescribing the High Cost Support Mechanism (HCSM) and Prescribing the Procedures for the Colorado High Cost Administration Fund, 4 CCR 723-41 (HCSM Rules), to increase certain switched access rates and to reduce others, and to secure support from the HCSM. The filing was made to comply with Commission

Tab K

pense. The revenue requirement resulting from the wage adjustment, according to the company, is $5,015,000 and $28,000 for the license contract adjustment. It therefore seeks additional revenues in the amount of $5,043,000.

The company's request that the proceeding be reopened to consider these two expense adjustments is hereby granted.

OHIO PUBLIC UTILITIES COMMISSION

Re Cincinnati Gas and Electric Company

Intervenors: Cities of Cincinnati and Middletown, General Motors Corporation, Emery Industries, Monsanto Chemical Company, Procter and Gamble, American Cyanamid Company, Ohio Council of Retail Merchants, Armco, Inc., Department of Energy, Citywide Coalition for Utility Reform, Inc., Ohio Citizens' Council, and Office of Consumers' Counsel et al.

Case Nos. 80-260-EL-AIR, 80-429-EL-ATA
March 18, 1981

APPLICATION *for a rate increase; granted as modified.*

Valuation, § 224 — Construction work in progress — Financial hardship test.

[OHIO] The commission rejected a contention that construction work in progress should not be included in rate base absent a showing of financial hardship and included an amount relating to ongoing construction that was more than 75 per cent complete and which represented less than 20 per cent of the remaining rate base. [1] p. 258.

Valuation, § 287 — Working capital allowance — Lead-lag studies.

[OHIO] Although noting that a properly conceived lead-lag study should produce results which were more accurate than those produced by the formula or balance sheet methods, the commission rejected a proffered lead-lag study stating that it was not accurate, comprehensive, and consistent. [2] p. 262.

Valuation, § 298 — Working capital allowance — Prepaid taxes.

[OHIO] For purposes of determining a utility's working capital allowance the state excise tax was found not to be a "prepayment" since the tax actually paid represented the prior year's liability. [3] p. 262.

Valuation, § 287 — Working capital allowance — Formula method.

[OHIO] The formula method of determining a utility's working capital allowance necessarily provides an approximation and any artificial tacking on of individual items ascribes a precision to the formula which simply does not exist; therefore, it would be area development expenses.[2] We disagree with that assumption. The issue of an area development expense was not even before the court in the City of Cleveland case and these are not the types of activities which the commission has traditionally classified as promotional advertising. See e.g., Re Toledo Edison Co. (1980) 36 PUR4th 209 (area development expenses included, despite commission policy against allowing promotional advertising expenses). Nor are they properly considered institutional advertising; there is nothing in the record of this case which suggests that these activities are designed to enhance the corporate image of CG&E. The test, then, is simply whether or not the expenses are reasonable, and in view of the obvious benefits these activities provide, such as increased jobs, an increased tax base, and economic growth, the commission believes that they are.

Assuming, however, only for the sake of argument, that the City of Cleveland test applies to these expenditures, they would still qualify for inclusion, since they provide two direct and primary benefits which are specifically related to the provision of electric service. The first benefit involves the retention of load. To the extent that CG&E is successful in persuading existing industries, such as Kenner Products Company, to remain in its service territory, the company's fixed costs, such as depreciation, property taxes, and return on investment, can be spread over a larger number of customers and kilowatt-hour sales. In turn, this should provide lower unit costs for all customers.

The second benefit involves the concept of load factor. Load factor is a measure of the efficiency of electrical consumption. Customer classes which are composed solely of large industrial customers generally have higher load factors than other customer classes. The record indicates that this is specifically true with respect to the CG&E system. Thus, to the extent that the company is successful in attracting or retaining large industrial customers, its overall load factor should improve, as should the efficiency with which it utilizes its generating equipment. Such improved efficiency should obviously benefit all of the company's customers. In view of these considerations, the commission finds that all of the amounts contained in Accounts 912 and 913 are properly includable in the test-year cost of service.

Rate Case Expense

[14] The applicant requests an allowance of $207,000 for the rate case

[2]Office of Consumers' Counsel also urges the exclusion of the entire amount ($1,000) included in Account 913-4, on the grounds that those expenses were not actually incurred during the test year. This argument ignores the fact that the commission has consistently decided all recent major rate cases on the basis of six months of actual data and six months of forecasted data, since the time constraints make it impracticable to use actual data for the entire test year. If the commission were to entertain numerous requests for minute adjustments to eliminate every discrepancy between the "six and six" figures and the utility's actual experience, it would defeat the whole purpose of using the six and six data in the first place. As a result, the commission will ordinarily decline to make such adjustments, unless it is shown that the six and six figures are not reasonably representative of normal operations. No such showing has been made in the context of this case. Moreover, if we were to rely solely on actual data in this proceeding, as OCC's argument implies that we should, the overall revenue deficiency, and hence the required increase in rates, would be greater than that resulting from the six and six figures.

expense associated with the current proceeding. The staff concurs in that recommendation. Office of Consumers' Counsel reiterates its traditional opposition to any allowance for this expense.

Office of Consumers' Counsel argues that rate case expense should be excluded because it results in a direct and primary benefit to the company's investors. That argument can be dismissed out of hand. The evidence clearly indicates that rate case expense is an ordinary and necessary business expense for a utility, and for that reason alone, it should be reflected in the test-year cost of service.

[15] The applicant proposes to amortize its current rate case expense over a one-year period, while the staff recommends a period of two years. Since the applicant has already noticed its next permanent rate application, Re Cincinnati Gas & E. Co. Case No. 81-67-GA-AIR, the commission believes that a one-year period is more reasonable and should be adopted.

The applicant also proposes an adjustment to reflect the unamortized portion of rate case expense associated with its last rate proceeding. Staff witness Hanna, noting that the company would otherwise recover only $70,313 of the $155,000 in expenses associated with its last case, suggests that the unrecovered portion should be amortized over a period of two years, if the commission agrees that it is significant enough to warrant such treatment. Office of Consumers' Counsel opposes that recommendation.

[16] Although the unrecovered portion may be significant when compared with total rate case expense, it is certainly not significant when compared with the company's total allowable expenses. As a result, we see no need to depart from our prior holdings that unrecovered rate case expense is a past loss which cannot be recovered through future rates. See, e.g., Re Cleveland Electric Illum. Co. Case No. 78-677-EL-AIR, May 2, 1979. The request for this adjustment should be denied.

Load Management Rider

On October 22, 1980, the commission approved an amendment of the applicant's load management rider, which made lower off-peak demand charges available to a larger number of customers. Re Cincinnati Gas & E. Co. Case No. 80-983-EL-ATA, Oct. 22, 1980. The change was intended to benefit churches, bakeries, and other entities whose usage occurs primarily during off-peak hours. In approving the change, however, the commission recognized that it might have a negative impact on the applicant's revenues. The applicant was therefore directed to file data estimating the total revenue impact of the change.

The applicant filed its response on November 6, 1980, estimating that the amendment would reduce its annual revenues by $276,000. Both the applicant and the staff recommend that test-year revenues be adjusted by that amount.

Office of Consumers' Counsel opposes the adjustment, on the grounds that there is no basis upon which to determine the accuracy of the estimated reduction. This argument is unconvincing. It is true, of course, that the reduction must necessarily be estimated, since it was not reflected in actual test-year revenues, but the staff reviewed the estimate submitted by the applicant, and

Tab L

Re Delta Natural Gas Company, Inc.

Case No. 99-176

Kentucky Public Service Commission
December 27, 1999

ORDER authorizing a natural gas local distribution company (LDC) to increase its rates to produce additional annual operating revenues of $419,702, reflecting an 11.6% authorized rate of return on common equity (ROE).

Base rates are increased by $2.957 million to reflect the roll-in of gas storage facility costs previously recovered through the gas cost recovery mechanism (GCR). Annual GCR revenues are reduced by some $2.538 million to reflect a corresponding removal of the storage facility costs from the GCR.

Commission allocates the base revenue increase entirely to firm customers, explaining that "today's competitive environment no longer supports" a policy of pricing service to commercial and industrial customers at a level above cost while pricing services to residential customers below cost.

Commission declines to employ a hypothetical capital structure as a remedy for a declining equity ratio. However, noting that the equity ratio had declined due in part to the fact that warmer than normal weather has prevented the LDC from earning its authorized rate of return on equity, the commission approves the use of a pilot weather normalization adjustment clause.

Commission rejects the proposed implementation of an experimental alternative regulation plan, finding that the plan focused primarily on guaranteeing that the LDC would earn its authorized ROE and lacked meaningful cost containment and performance-based incentives.

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1. VALUATION, § 281
[KY.] Gas utility plant in service — Gas storage facilities — Roll-in to rate base from gas cost recovery mechanism — Local distribution company.
p. 137.

2. AUTOMATIC ADJUSTMENT CLAUSES, § 23
[KY.] Gas cost recovery mechanism — Storage costs — Roll-in to base rates — Local distribution company.
p. 137.

3. RATES, § 262
[KY.] Cost elements — Gas storage facilities — Roll-in from adjustment clause to base rates — Local distribution company.
p. 137.

4. EXPENSES, § 125
[KY.] Natural gas local distribution company — Storage facility costs — Roll-int o base rates — Removal for gas cost recovery mechanism.
p. 137.

5. AUTOMATIC ADJUSTMENT CLAUSES, § 11
[KY.] Gas cost recovery mechanism — Cost elements — Removal of storage costs — Roll-in to base rates — Local distribution company.
p. 137.

6. VALUATION, § 96
[KY.] Accumulated depreciation — Ascertainment — Increase to reflect roll-in of storage facilities to rate base — Natural gas local distribution company.
p. 137.

7. VALUATION, § 290
[KY.] Cash working capital — One-eighth formula method — Natural gas local distribution company.
p. 137.

8. VALUATION, § 298
[KY.] Working capital — Prepayments — 13-month average balance — Natural gas local distribution company.
p. 138.

9. VALUATION, § 300
[KY.] Working c
supplies — 13-month
ral gas local distributio
p. 138.

10. VALUATION, § 3(
[KY.] Working
supplies — Gas in stor
balance — Natural ga
pany.
p. 138.

11. VALUATION, § 1
[KY.] Property
debt issuance costs —
to plant included in
local distribution com
p. 138.

12. VALUATION, § 1
[KY.] Property
Accumulated deferre
gas local distribution
p. 138.

13. VALUATION, §
[KY.] Advances
base reduction — Na
company.
p. 138.

14. VALUATION, §
[KY.] Custome
rate base — Exclus
from operating expe
distribution company
p. 138.

15. VALUATION, §
[KY.] Natural
pany — Net investm
p. 139.

16. VALUATION, §
[KY.] Measure
ment rate base — N
company.
p. 139.

Canada Mountain

Delta proposes to reduce test-period expenses by $121,120 for costs related to Canada Mountain.[44] The AG proposes that an additional $35,918 in related Canada Mountain expenses be disallowed.[45] As we have included the Canada Mountain investment in Delta's base rates,[46] the Commission finds that both parties' adjustments should be denied.

Customer Deposits

[26] Delta proposes to increase test-period expenses by $35,692 to include the interest on customer deposits in operating expenses.[47] As previously discussed,[48] the Commission has determined that it is inconsistent not to deduct the customer deposit balance from rate base while allowing the corresponding interest expense to be included in Delta's operating expenses. For this reason, Delta's proposed adjustment to move interest on customer deposits "above-the-line" should be denied.

Medical Expense Adjustment

[27] In its application, Delta proposed to increase test-period expenses by $77,561 to reflect the recovery of funds from Delta's stop-loss insurance coverage that was applicable to 1997.[49] Delta's controller testified at the hearing, however, that this adjustment had not been reduced to reflect the amounts allocated to construction and subsidiaries and should be reduced to $57,380 to reflect such allocation.[50] The Commission accepts the revised medical expense adjustment of $57,380.

Rate Case Expense

[28-30] Delta proposes to increase test-period expenses by $48,333 to reflect amortizing its estimated rate case expense of $145,000 over a 3-year period.[51] The AG proposes a reduction of $19,920 in operating expenses to eliminate $24,960 of rate case expense amortization for Case No. 97-066; to reduce rate case expense amortization for the current case to $29,000; and to remove Delta's cost to participate in the Department of Transportation's ("DOT") Pipeline Safety training program in 1999 in the amount of $23,960.[52]

The AG argues that Delta's rate case expense should be normalized rather than amortized. He argues that the timing of a rate case is a matter entirely within the discretion of the utility. Ratepayers, he asserts, should not therefore have to bear the cost of two rate cases merely because Delta chose to seek rate relief before the amortization period for Delta's prior rate case expenses had completely run.[53]

Delta argues in response that the AG's normalization methodology would deny it the recovery of expenses already authorized by the Commission. It notes that the proposal is inconsistent with the AG's recommendations in Case No. 99-046, ignores the conceptual differences between amortization and normalization, and violates the Commission's Order in Case No. 97-066.[54]

Finding that the AG's proposal to exclude Delta's allowed rate case expense from Case No. 97-066 is unlawful and unreasonable, we reject the proposal. Implicit in the AG's proposal is the concept that utilities should be discouraged from seeking rate adjustments by preventing "carte blanche dollar-for-dollar recovery of multiple rate case expense each time it comes in."[55] Such an argument fails to take into account KRS 278.180, which permits a utility to apply for rate adjustments without limitation or restriction.[56] Moreover, it conflicts with the longstanding principle that rate case expenses are appropriately included in utility rates. *See West Ohio Gas Co. v. Public Utilities Comm'n*, 294 U.S. 63, 74 (1935) (holding that rate case expenses "must be included among the costs of operation in the computation of a fair return" and that "[t]he charges of engineers and counsel, incurred in defense of its security and perhaps its very life, were as appropriate and even necessary as expenses could well be").

The AG's policy, moreover, would have the unintended consequence of discouraging utilities from seeking rate relief. For example, the record in this case demonstrates that Delta's reluctance to seek rate relief in a timely manner has had a negative effect on its financial condition and contributed to the erosion of the equity component of its capital structure.

The AG also contends that the Commission should exclude from rate recovery any expenses associated with Case No. 99-046 and with Delta's Experimental ARP.[57] The AG argues that Delta has not requested recovery of these expenses, that he has not had adequate opportunity to review these expenses, and that the proposed Experimental ARP was for the primary benefit of shareholders.

The Commission finds no merit in these arguments. We note that Delta's application in this proceeding included a revised version of its Experimental ARP and that much of the evidence regarding this plan was originally submitted in Case No. 99-046. While Delta certainly intended for its proposal to benefit its shareholders, the Commission fails to discern how Delta's motive in Case No. 99-046 differs in any fashion from its motives in a general rate adjustment proceeding. In each instance, the utility's paramount interest is to protect the interests of its shareholders. Moreover, the AG presents no legal authority to suggest that Delta's presentation of its Experimental ARP falls outside the holding of *West Ohio Gas Co.*

The Commission finds that, based upon Delta's most recent cost filings,[58] Delta incurred expenses of $35,518 to prosecute Case No. 99-046 and expenses of $183,235 to prosecute this proceeding. We further find that these costs should be amortized over a 3-year period to reflect the normal interval between Delta's general rate adjustment applications. Accordingly, rate case expense should be increased by $72,918.

The AG asserts that Delta recorded the 1998 and 1999 DOT Pipeline Safety program costs in its test-period operating expenses. The AG recommends that Delta's test-period operating expenses be reduced by $23,960 to remove the "out-of-period" expense item and to avoid a doubling of the expense for the same program. The Commission finds that the AG's adjustment is reasonable and, therefore, reduces operating expenses by $23,960.

Public Service Commission Assessment

[31, 32] The Commission has increased Delta's Public Service Commission assessment by $3,449 to reflect the impact of the Commission-approved revenue increase on this expense.

Pension Expense

[33] Delta incurred $292,818 in pension expense during the test period. The AG proposes to decrease this expense by $82,599 to reflect the findings of the actuary report of April 1, 1999 and the use of the operation and maintenance ratio of 73.98 percent.[59] The Commission finds that Delta must invest $267,238 in its employee pension fund for the 12-month period ending April 1, 2000.[60] This amount combined with the test-period fees paid to Hand and Associates, Delta's actuary, the American Industry Trust Company, Delta's trustee, and the Pension Benefit Guaranty Corporation of $46,354[61] results in a pro forma pension expense of $307,592, or $14,773 above Delta's test-period level. The Commission has applied the 73.98 percent operation and maintenance ratio to the gross pension adjustment of $14,773 to arrive at our pension expense adjustment of $10,929.

401(k) Expense

The AG argues that Delta's 1998 401(k) expense includes a reclassification of the pension expense due to an account distribution correction made for a trustee for the year 1997. Applying the operation and maintenance ratio of 73.98 percent to the $18,736 reclassification, the AG proposes to reduce 401(k) expense by $13,861. The Commission accepts the proposed adjustment.

Bad Debt Expense

[34] Contending that Delta's test-period bad debt expense is abnormally high, the AG recommends that bad debt expense be adjusted to reflect a bad debt-to-revenue ratio of 0.67 percent, Delta's average bad debt ratio for the 4-year period ending 1998. Using the 0.67 percent debt-to-revenue ratio and its recommended base revenues and GCR revenues, the AG recommends a reduction of $95,204 in test-period

Tab M

SOUTH CAROLINA PUBLIC SERVICE COMMISSION

Re Duke Power Company

Intervenors: Consumer Advocate of South Carolina, South Carolina Energy Users Committee, and Clifton Power Corporation

Docket No. 86-188-E, Order No. 86-1116
November 5, 1986

APPLICATION *for authority to increase electric rates and charges; granted as modified, with discussion of "economic benefits" rate base allowance for newly constructed nuclear generating unit.*

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1. Conservation, § 1 — Electric utilities — Load management — Reduction in peak demand.

[S.C.] An electric utility was directed to pursue aggressively a voluntary load management program designed to reduce the growth in peak demand and contribute to conservation by reducing total energy use; the utility's program would include promotion of energy-efficient building structures and appliances, residential conservation rates, time-of-day pricing, utilization of emergency generators, plant modernization, and utility control of residential water heaters and air conditioners during peak demand periods.

2. Expenses, § 122 — Electricity — Capital capacity purchased power — Levelized cost recovery.

[S.C.] An electric utility with an ownership interest in the Catawba unit 2 nuclear generating station was permitted to recover capital capacity purchased power costs relating to the generating station under a levelized approach.

3. Valuation, § 27 — Rate base determination — Measures of value — Economic benefits analysis — Nuclear plant.

[S.C.] An electric utility's full allocated investment in the Catawba unit 2 nuclear generating station was included in plant in service as of the date that the unit was declared in commercial operation; the commission rejected an economic benefit analysis that would have resulted in a rate base exclusion of certain costs associated with the unit, finding that the economic benefits analysis was inherently flawed in that it required the utility to anticipate events that could not be forecasted realistically.

4. Revenues, § 2 — Adjustment to test-year levels — Increased patronage — Method of computation — Electric utility.

[S.C.] An electric utility's test-year revenues, fuel expenses, and taxes were adjusted to reflect the growth in the number of customers served; the adjustment was computed using a formula method.

5. Expenses, § 9 — Ascertainment of expenses — Adjustment to test-year levels — Known and measurable changes — Electric utility.

in this case with the additional Cherokee expenses. The Consumer Advocate has presented no evidence to us that would cause us to conclude that the additional, and final, expenses associated with the abandonment of Cherokee Nuclear Station should either be disallowed in whole or part, or not be amortized over the years remaining of the 10-year period approved in prior proceedings.

Therefore, based on the foregoing, the Commission finds that the motion to disallow the additional Cherokee abandonment costs should be denied. Additionally, to maintain the integrity of the original amortization period, the Commission finds that the Consumer Advocate's alternative motion to amortize the costs over a separate ten year period should be denied.

R. *TMI CLEAN-UP EXPENSES*

[16] The Company included in cost of service a proportional share of the costs paid by Duke associated with cleanup of the damaged reactor at Three Mile Island. The Consumer Advocate made a motion to this Commission to disallow those expenses, on the grounds that the monies associated with the TMI Cleanup — which amount to $311,000 for South Carolina ratepayers — are unduly burdensome. We grant the Consumer Advocate's motion.

Duke's monetary contribution to the cleanup efforts of Three Mile Island to date is $2,152,560, with an additional $4,305,738 committed over the next four years. The South Carolina retail portion of the TMI expense totals approximately $311,000. Duke witness Rolfe, the chairman of Duke's internal TMI-2 Cleanup Technology Utilization Task Force, testified that no one has required Duke to contribute towards the cost of the cleanup of TMI. Mr. Rolfe did not know what portion of the monetary contribution South Carolina ratepayers had contributed. He did testify, however, that North Carolina ratepayers were not contributing toward the costs for the cleanup: the shareholders were paying for North Carolina's share.

Mr. Rolfe testified that Duke will gain long-term benefits from its involvement in the cleanup which "far exceed the cost for the cleanup." He further testified that not only South Carolina but also North Carolina ratepayers had benefitted from the research and development that has come out of TMI.

No one required Duke to participate in the cleanup of TMI. Duke simply volunteered to be a part of this cleanup. It is apparent from the testimony that South Carolina ratepayers would benefit from Duke's involvement in the cleanup as do North Carolina ratepayers even if the costs were not recovered from the ratepayers. While the Commission lauds Duke's efforts in participating in the TMI cleanup and being a leader in the nuclear industry in doing so, the Commission finds that this voluntary effort should be borne by the shareholders and not recovered through rates. Therefore the Commission concludes that the Consumer Advocate's motion should be granted.

S. *GENERAL RATE CASE EXPENSES*

[17] The Company included in this case regulatory commission expenses in accordance with the Uniform System of Accounts adopted by this Commission. Included within this amount are expenses associated with general rate cases in South Carolina. The Consumer

Advocate has made a motion that this Commission order the "sharing" of such expenses between shareholders and ratepayers on the theory that the costs of the Company's proving its case before the Commission are intended solely to benefit shareholders. We deny the motion of the Consumer Advocate.

The expenses under consideration, which the Company incurred during the test year, are properly included. The Commission is required by statute to fix just and reasonable rates. In order to do so, general rate case proceedings such as this docket to examine the entire rate structure must be held to make a determination as to the justness and reasonableness of a utility's rates. Just and reasonable rates are in the best interest of the using and consuming public and reasonable operating expenses relating to the fixing of such rates are fairly and properly includable in cost of service. The Commission finds that the Consumer Advocate has presented nothing which would cause us to adopt a different position. Therefore, the Consumer Advocate's motion is denied.

T. *ACCUMULATED PROVISION FOR AMORTIZATION OF NUCLEAR FUEL*

[18] Duke has included in rate base the cost of the initial nuclear fuel core for Catawba 2. Additionally, Duke has included the cost of nuclear fuel amortized in fuel expense. Duke has failed, however, to subtract the amount of nuclear fuel amortized in cost of service from the nuclear fuel balance in rate base. The Consumer Advocate recommends the rate base be reduced by the amount of the nuclear fuel amortized and included in the cost of service. This adjustment is the same conceptually as the adjustment made by Duke to the accumulated depreciation account for depreciation of Catawba Unit 2.

Consumer Advocate witness Wilkins testified an adjustment should also be made for annualized nuclear fuel expenses for Catawba 1, but he could not determine the amount of the adjustment due to lack of information.

The Commission finds merit in the Consumer Advocate's recommendation. Since a similar adjustment was made for Catawba 2 and such an adjustment is proper under regulatory accounting practices, the Commission will adopt the Consumer Advocate's recommendation. Using the information available to Staff, Staff computed the necessary adjustment to reduce the Company's rate base by $475,000. The Commission finds this adjustment to be appropriate.

U. *OTHER ADJUSTMENTS*

The Commission has considered all other adjustments to, or treatment of, revenues, expenses or rate base items proposed by the Company in its presentation, not specifically addressed herein, to which no party objected thereto, and have found the adjustments fair and reasonable and adopted same for purposes of this proceeding. All other adjustments proposed by any Party inconsistent therewith have been reviewed and found to be unreasonable or inappropriate for ratemaking purposes and are hereby denied.

V. *TAXES*

The Commission hereby will adjust general taxes, state and federal income

Tab N

LEXSEE 2003 N.J. PUC LEXIS 259

IN THE MATTER OF THE VERIFIED PETITION OF ROCKLAND ELECTRIC COMPANY FOR THE RECOVERY OF ITS DEFERRED BALANCES AND THE ESTABLISHMENT OF NON-DELIVERY RATES EFFECTIVE AUGUST 1, 2003; IN THE MATTER OF THE VERIFIED PETITION OF ROCKLAND ELECTRIC COMPANY FOR APPROVAL OF CHANGES IN ELECTRIC RATES, ITS TARIFF FOR ELECTRIC SERVICE, ITS DEPRECIATION RATES, AND FOR OTHER RELIEF

DOCKET NO. ER02080614; DOCKET NO. ER02100724

New Jersey Board of Public Utilities

2003 N.J. PUC LEXIS 259

July 31, 2003, Dated

CORE TERMS: deferred, energy, recommended, recommendation, consolidated, disallowance, customer, base rate, additionally, deferral, auction, accrued interest, rate of return, modification, accounting, transition, reduction, temporary, hedging, interim, capital structure, interest rate, depreciation, amortization, implemented, disallow, savings, offset, priced, Energy Competition Act

PANEL: [*1] JEANNE M. FOX, PRESIDENT; FREDERICK F. BUTLER, COMMISSIONER; CAROL J. MURPHY, COMMISSIONER; CONNIE O. HUGHES, COMMISSIONER; JACK ALTER, COMMISSIONER

OPINION: ENERGY

SUMMARY ORDER

(SERVICE LIST ATTACHED)

BY THE BOARD:

This Summary Order memorializes, in summary fashion, the action taken by the Board of Public Utilities ("Board") in these matters at its July 16, 2003 public agenda meeting by a vote of five Commissioners. The Summary Order is being issued for the purpose of implementing new rates on August 1, 2003, consistent with the requirements of the Electric Discount and Energy Competition Act ("EDECA"), N.J.S.A. 48:3-49 et. seq. and the Board's Orders implementing EDECA. The Board will issue a more detailed Final Decision and Order in these matters, which will provide a fuller discussion of the issues as well as the reasoning for the Board's determinations.

These matters concern petitions filed by Rockland Electric Company ("RECO," "Company," or "Rockland") requesting; (1) recovery of its deferred balances and the establishment of non-delivery rates ("deferred balances case"); and (2) approval of changes in its distribution rates, including changes to its tariff for [*2] electric service, its depreciation rates and other relief ("base rate case"). RECO filed its deferred balances case on August 29, 2002 and its base rate case on October 1, 2002. The cases were transmitted to the Office of Administrative Law ("OAL") on September 12, 2002 and October 16, 2002, respectively, and consolidated for hearing.

Additionally, pursuant to the Board's Order dated July 22, 2002, *Order Directing the Filing of Supplemental Testimony and Instituting Proceedings to Consider Audits of Utility Deferrals*, BPU Dkt. No. ER02050303, *et al.*, an audit was performed on RECO's deferred balances, the results of which were placed in the record of the deferred balances case at the OAL.

These matters come before the Board on a record developed in hearings before Administrative Law Judge ("ALJ") William Gural, who issued an Initial Decision ("I.D.") on June 12, 2003. The parties to the proceeding included the

Company, Board Staff and the Ratepayer Advocate ("RPA"). Participant status was granted to Jersey Central Power and Light Company and Public Service Electric and Gas Company. Exceptions and Replies to Exceptions were filed with the Board. After the hearings were [*3] completed at the OAL, both the Company and the Ratepayer Advocate supplemented their positions based upon 12 months of actual data.

The Board acknowledges and appreciates the efforts of ALJ Gural in presiding over this consolidated proceeding and in producing a detailed and thorough Initial Decision.

Based on our review of the extensive record in this consolidated proceeding, the Board has determined that the Initial Decision, subject to certain modifications, which willbe set forth herein, represents an appropriate resolution of this proceeding. Accordingly, except as specifically noted below, and as will be further explained in a detailed Final Decision and Order which shall be issued, the Board HEREBY ADOPTS and incorporates by reference as if completely set forth herein, as a fair resolution of the issues in this consolidated proceeding, the Initial Decision.

The modifications and clarifications to the Initial Decision which the Board HEREBY ORDERS, are based upon 12 months of actual data and are summarized as follows:

A. Base Rate Case

1. The ALJ concurred with RECO's position that a 12% return on equity with an overall rate of return of 9.33% is appropriate. [*4] The RPA recommended a return on equity of 9.25% and an overall rate of return of 7.92%. Staff recommended a return on equity of 9.5% and an overall rate of return of 7.90%. For reasons that will be further explained in a detailed Final Order which shall be issued, the Board HEREBY FINDS that, based on the evidence in the record and in light of current market conditions, the capital structure and level of return recommended by the ALJ are unreasonable. Accordingly, the Board HEREBY MODIFIES the ALJ's Initial Decision with respect to capital structure and return on equity and HEREBY ORDERS (1) that RECO's appropriate return on equity is 9.75%, with an overall rate of return of 8.02%; and (2) that the capital structure and embedded cost of debt to be employed for ratemaking purposes is as follows:

TYPE OF CAPITAL	RATIOS	RATE	WEIGHTED COST RATE
LONG-TERM DEBT	54.00%	6.54%	3.53%
EQUITY	46.00%	9.75%	4.49%
TOTAL CAPITAL	100.00%		8.02%

2. The Board HEREBY MODIFIES the ALJ's Initial Decision that no adjustment should be made to reflect consolidated tax savings and HEREBY ADOPTS the position taken by Staff in its Reply Brief that rate base should [*5] be reduced by $ 1.329 million to reflect tax savings achieved by RECO's parent company through offsetting tax losses of affiliates with RECO's positive taxable income. The Board concurs with Staff that, consistent with applicable law and longstanding Board policy, these savings should be shared with customers.

3. All the parties in the base rate case agree that there is a significant excess depreciation reserve. The Company proposed a 20-year amortization of its calculated excess reserve of $ 11.8 million. The RPA claimed the proper excess reserve was $ 22.1 million, based upon the Company's asset lives, but excluding the Company's future net salvage assumptions from the depreciation rates. The RPA accepted the Company's proposal of a 20-year amortization. Both Staff and the ALJ adopted the RPA's recommendation. The Board HEREBY MODIFIES the Initial Decision so that the RPA's recommended level of excess reserve is amortized back to ratepayers over 10 years. The Board FINDS this to be an appropriate modification in order to offset the increase associated with the deferred balances that were incurred over the 4-year transition period, as well as the increase in Basic Generation [*6] Service ("BGS") charges for current service.

4. The ALJ did not specifically address certain issues but instead implicitly adopted Staff's position on these issues by adopting Staff's pro-forma operating income. Accordingly the Board HEREBY ADOPTS Staff's recommendations with regard to these issues, which include miscellaneous service revenues, electric rent revenues and removal of certain incentive compensation expenses.

5. While the Board ADOPTS the Initial Decision concerning Pension Expense and Other Post-Employment Benefits ("OPEBs"), the Board DIRECTS RECO to cease its deferred accounting treatment for Pension Expense and OPEBs

relative to the difference between the amounts allowed in rates and the book expense, as of August 1, 2003. The Board notes that RECO was the only utility that was allowed to use this type of deferred accounting for such expenses and FINDS that on a going forward basis, in order to provide consistency among the utilities, this deferred accounting treatment is no longer appropriate, and should be discontinued.

6. The Board HEREBY ADOPTS Staff's recommendation to include the Company's proposed 12-month actual adjustment of $ 0.225 [*7] million to expenses related to the Company's common expense allocation, as this amount reflects the elimination of the double-count issue raised on the record. In addition, the Board HEREBY ADOPTS Staff's recommendation to include the Company's proposed 12-month actual adjustment of $ 0.031 million for maintenance costs of additional telephone lines installed due to the implementation of the hourly energy pricing program. It is also noted that other investment associated with the hourly energy pricing program has been reflected in this case without opposition by any party.

7. The Board HEREBY ADOPTS the recommendation by Staff and the RPA to reflect only that portion of interest expense on customer deposits associated with the customer deposit balance deducted from rate base.

8. With regard to Utility Plant In Service, the Board HEREBY MODIFIES the ALJ's Initial Decision and authorizes the Company to file a Phase II proceeding on or before September 1, 2004 to address the Upper Saddle River and the Darlington projects and associated flow-through impacts, which the record reflects and the ALJ properly found were not completed in the test year. The Board HEREBY ORDERS [*8] that the Company be permitted to include in this Phase II filing a request for recovery of the costs of reliability enhancements, which it had sought in this case, but which the record reflected and the ALJ appropriately concluded, had not actually been performed. As part of the Phase II proceeding, the Board FURTHER ORDERS that the parties review whether these or other projects included in the proceeding are transmission related or are distribution related. RECO will have the burden of proof with respect to the classification of these facilities as transmission (FERC-regulated) or distribution (BPU-regulated) plant.

9. The Board HEREBY REJECTS the ALJ's finding in the Initial Decision that no change be made in the bad check charge and the reconnection charge. In recognition of the record presented concerning the actual costs associated with these charges, the Board HEREBY ORDERS that the bad check charge be raised from $ 3.50 to a flat fee of $ 7.00 and that the reconnection charge be raised from $ 7.00 to $ 21.00 for all time periods. Additionally, the Board HEREBY ADOPTS RECO's proposal on line extension charges for new residential subdivisions and multiple occupancy [*9] buildings, which updates the charges to reflect current costs, as well as its proposed late payment fee for non-residential and non-governmental customers.

10. In summary, the modifications summarized herein result in a decrease in distribution rates of $ 7.217 million, which equates to an overall percentage base rate decrease of 5.3%.

B. Deferred Balances Case

1. Although the Board recognizes the valuable analysis performed by the Board's Auditors, Synapse Energy Economics, Inc. ("Synapse") (deferred balances) and Larkin & Associates, PLLC (accounting issues), including Synapse's analysis and recommendation to disallow $ 26.8 million (excluding interest) from RECO's Basic Generation Service ("BGS") deferred balance related to an asserted possible extension in the parent company's Transition Power Sales Agreement ("TPSA") with the purchaser of its divested generating assets, and related avoidance of hedging costs, in view of the totality of the record, the Board HEREBY ADOPTS the $ 14.0 million in TPSA and hedging cost disallowances recommended by Staff in its Initial Brief and accepted by the ALJ, and HEREBY reduces the BGS deferred balance by this amount.

2. [*10] The ALJ agreed with the opinion of Synapse regarding the timeliness of RECO's transfer of its Eastern Division, which serves approximately 90% of its load, from the New York Independent System Operator ("NYISO") to the Pennsylvania-New Jersey-Maryland Interconnection, L.L.C. ("PJM"). In so doing, the ALJ rejected the position of the RPA that the transfer to PJM should have occurred as early as August 1, 1999. The majority of the Board agrees with the Staff position set forth in its Initial Brief that RECO should have taken the necessary preliminary steps to initiate the transfer four months sooner than it did, and should not have required two months following the FERC's approval to install the necessary metering and communication equipment. Therefore, the Board HEREBY MODIFIES the Initial Decision

Tab O

LEXSEE 2003 NY PUC LEXIS 427

Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of St. Lawrence Gas Company, Inc. for Gas Service.
Petition of St. Lawrence Gas Company, Inc. for a Waiver of the 150-Day Provision of the Commission's Statement of Policy on Test Periods in Major Rate Proceedings, filed in C. 26821

CASE 02-G-1275; CASE 02-G-1011

New York Public Service Commission

2003 N.Y. PUC LEXIS 427

August 4, 2003, Issued and Effective

CORE TERMS: customer, billing, vendor, staff, transportation, payroll, residential, non-utility, annual, capability, rate case, interruptible, satisfaction, amortization, delivery, depreciation, marketer, sharing, rate increase, margin, accounting, negotiation, effective, commodity, deferral, earnings, target, notice, reconciliation, three-year

DISPOSITION: [*1] ORDER ADOPTING THE TERMS OF A JOINT PROPOSAL

PANEL: COMMISSIONERS PRESENT: William M. Flynn, Chairman; Thomas J. Dunleavy; James D. Bennett; Leonard A. Weiss; Neal N. Galvin

OPINION: At a session of the Public Service Commission held in the City of Albany on July 23, 2003

BY THE COMMISSION:

INTRODUCTION

On September 30, 2002, St. Lawrence Gas Company, Inc. (St. Lawrence or the company) proposed to increase its annual gas revenues by $ 1.7 million (7.95%). Consequently, the Commission suspended the company's filing and initiated these proceedings to examine its rates.

In accordance with the set schedule, Department of Public Service Staff audited and investigated the rate filing. Evidentiary hearings were scheduled to begin in April 2002; however, they were put off to provide the parties an opportunity to use alternative dispute resolution.

In January 2003, the parties first met to consider the contested issues. Notice of their discussions was provided in accordance with the requirements of 16 NYCRR § 3.9. At the parties' request, a mediator was assigned from the Office of Hearings and Alternative Dispute Resolution and, on May 9, 2003, the parties submitted their Joint Proposal.

Notice of the [*2] Joint Proposal was issued on May 14, 2003 and the public was invited to submit comments on it. Commissioner Neal Galvin and the presiding officer assigned to this case conducted two public statement hearings. During the first hearing in Ogdensburg on the afternoon of June 11, 2003, written comments were received from the Assemblyman for the 118th Assembly District, Darrel J. Aubertine. The Assemblyman expressed concern for residential and small business customers whose gas delivery rates would increase. He also expressed concern about the parties' proposal to increase minimum charges. No one spoke at the second hearing held that evening in Massena.

In addition to the company and Department of Public Service Staff (Staff), Alcoa, Inc., Multiple Intervenors and the International Brotherhood of Electrical Workers, Local 97 have all endorsed the Joint Proposal.

THE PROPOSED TERMS AND PROVISIONS

Instead of the $ 1.7 million rate increase St. Lawrence first proposed, the Joint Proposal would limit the company to a $ 595,000 (2.7%) increase, starting on September 1, 2003. It would also freeze delivery rates for a three-year period, through September 30, 2006. Under the proposal, residential [*3] heating customer rates would increase by about four to six percent. Rates for small general service customers would increase by about three percent.

The parties' rate design proposals rely on and apply the results of an embedded cost of service study, which suggested that the majority of the rate increase be allocated to residential and small general firm service (Service Classifications 1 and 2). The parties propose that much of the additional revenue be collected by increasing the minimum charges for gas service. The minimum for residential service would rise from $ 4.92 to $ 7.20 a month; the minimum monthly charge for small general firm service would go from $ 4.92 to $ 10.25. The parties point out that, even at the proposed levels, St. Lawrence's charges would remain well below those of other gas utilities that operate in the upstate region.

Also with respect to general service, the Joint Proposal would apply the same transportation service charges to sales and transportation customers. The recent unbundling of St. Lawrence's gas commodity costs eliminates any basis for applying different transportation rates to general service customers.

The Joint Proposal does not alter the [*4] prevailing sales and transportation service rates for large volume customers (Service Classification 3). Nonetheless, the load balancing charges for these customers would decrease due to the lower balancing costs and volumes being projected for the upcoming rate year. The transportation rates for larger customers in SC-2 would decline to apply the cost study results provided in this case.

The parties arrived at a $ 595,000 rate increase proposal by increasing the company's statement of operating revenues and by decreasing the operating expenses reflected in its September 2002 rate filing. Revenues were increased to reflect customer additions, cogeneration revenues, a non-utility royalty, interest on late payments, and a lower level of state gross income taxes. Operating expenses were reduced and adjustments made to payroll, employee benefits, billing system costs, rate case expenses, and for productivity and inflation. Various adjustments were also made to the company's depreciation expenses, taxes, and rate base. n1

n1 The Joint Proposal's consideration of St. Lawrence's marginal revenues from the sale of interruptible service is noteworthy. The parties have projected a slightly lower level of interruptible sales during the upcoming rate year than previously included in rates. St. Lawrence will still receive an incentive to make such sales, but the incentive would only apply to sales made $ 100,000 above or below the target. While large general service customers (SC-3) are participating in the incentive sharing mechanism this year, in the future they would be excluded to improve the price structure for large interruptible and firm service customers.

[*5]

The Joint Proposal would permit St. Lawrence to use certain cost deferrals and amortizations during the next three years. Deferral accounting would continue to be used for computer-related (Y2K) costs. It would also apply to the company's rate case, pension and post-retirement benefit expenses.

The proposed rates are designed to provide St. Lawrence a reasonable opportunity to earn a 9.8% return on equity. The company would share equally with ratepayers any earnings it may achieve above 10.1% over the next three-year period.

The Joint Proposal also addresses the service quality St. Lawrence provides its customers. It would establish service quality performance mechanisms addressing customer complaints made to the Commission and customer satisfaction levels. St. Lawrence would have to keep customer complaints below a specified level to avoid the imposition of a revenue adjustment. It must also perform a survey to measure customer satisfaction. St. Lawrence could be assessed a revenue adjustment if customer satisfaction were to fall below established levels. During the next three years, the company will enhance its retail gas access outreach and education efforts, and increase customer [*6] awareness and knowledge of the service choices that are available.

The Joint Proposal acknowledges several matters that it does not attempt to resolve at this time. It notes that the Three Nations Bridge spanning the St. Lawrence River is an aged facility that may soon be replaced. It is not certain that a gas supply pipeline would be allowed on the new bridge.

The Joint Proposal also notes that Staff and St. Lawrence plan to meet (before the end of 2004) to discuss a revenue loss expected in 2011 that is related to certain proceeds the company received when a cogeneration customer terminated its gas service contract. The company plans to work with the parties to update its gas transportation operating procedures. St. Lawrence plans as well to provide a full depreciation study in its next rate filing.

SUPPORTING STATEMENTS

The Company

St. Lawrence favors the Joint Proposal's multi-year ratemaking approach and the rate stability it will provide. The company supports the current rate proposal stating that the additional revenues are needed for operating costs, a new employee position, and a new billing system. St. Lawrence points out that its distribution service rates have not [*7] increased since 1995 and the proposed rates will remain among the lowest rates in the State.

The company urges the Commission to adopt the terms of the Joint Proposal in order to improve its financial condition and provide customers good service. It insists that the proposed rate increase has been kept to the lowest possible level that will permit the company to conduct proper business activity and to serve customers well.

Staff

Staff considers the Joint Proposal to be a fair resolution of the disputed issues that arose in this case. It believes that the proposed rates are reasonable, being substantially lower than the original rate request and frozen for three years. Staff states that the company's costs have been properly separated for utility functions and non-utility operations. Staff supports the replacement of the company's current billing system with one that is better suited for competitive market developments.

From its participation in these proceedings, Staff represents that the Joint Proposal is in the public interest, and that it balances ratepayer and investor interests well. Staff believes that the Joint Proposal promotes the long-term viability of the utility [*8] company operations and considers it to be consistent with Commission policy and practice.

Alcoa and Multiple Intervenors

Alcoa, Inc. operates industrial facilities in Massena and is the company's single largest customer. Multiple Intervenors is an association of 55 large commercial and industrial energy consumers that have facilities throughout the State, including the St. Lawrence service area. Both parties support the Joint Proposal's treatment of large customers and favor the three years of rate stability that it provides.

They consider the allocation of the proposed increase among the service classes to be fully supported by the cost of service results that were presented here. They state as well that the proposed rate design is consistent with the Commission's action in previous St. Lawrence rate proceedings. They specifically address and support the Joint Proposal provisions pertaining to interruptible service, load balancing charges and the rates for large use customers. Multiple Intervenors believes the proposed terms will promote economic stability, regional development, and employment in the service area and urges that they be adopted.

IBEW Local 97

In February [*9] 2003, Local 97 ratified a labor contract with St. Lawrence on behalf of the company's union-represented employees. Local 97 supports the Joint Proposal provisions that concern its membership, including payroll expenses, pension and employee benefits. Overall, it considers the proposal to be fair and reasonable--despite any doubts it may have about the need for a productivity adjustment. Given the amount of rate relief the utility company is now seeking and the stable delivery rates provided for three years, Local 97 believes the proposed terms should be adopted.

DISCUSSION AND CONCLUSION

We have reviewed the terms of the Joint Proposal, examined the St. Lawrence rate filing, considered the record in this case and have taken into account the comments received. In sum, we find that the multi-year rate plan presented here will properly serve customer interests and maintain the company's operations. As discussed below, we have determined that the proposed terms are just, reasonable and in the public interest and they are therefore being adopted.

To begin, we observe that the proposed terms are not opposed by any of the parties who participated in these proceedings. To the extent the [*10] active parties represent varied interests that are concerned about the utility company operations, their concurrence in the Joint Proposal supports its adoption.

We also note that very few customers submitted comments either supporting or opposing the rate filing and the Joint Proposal. The hearings convened in the service area were sparsely attended and only one statement was received that challenges the proposal.

As to the size of the proposed rate increase, Staff's audit and investigation, and the parties' alternative dispute efforts, were able to substantially reduce the company's original rate filing. The parties' efforts have also ensured that the new delivery rates will remain in place (and not be increased) for an extended period, at least the next three years. These results are advantageous for all customers, including the residential and small commercial customers who will see a modest increase in their bills. They stand above any criticism that was presented during the hearings.

Given the modest increase in delivery rates for the next three years, it is doubtful that the gas delivery prices will have any adverse impacts on the economic development and prevailing conditions [*11] in the service area. Moreover, the cost of service study results presented and reviewed in this case support the allocation of the revenue increase to the company's residential and small general service customers. The cost of service study results also support several other rate changes.

St. Lawrence's minimum charges for gas service have been very reasonable and, even with the changes proposed here, they will remain well below the levels that other utility companies charge in the upstate region. To the extent that the company's additional revenues are being collected in these charges, we find that such action is justified by the available evidence and that the potential impacts are acceptable.

We also find here that it is warranted to adjust the company's general service transportation rates to improve the unbundling of the commodity and delivery components that sales and transportation customers pay. This action provides customers better price signals and helps to maintain the integrity of the company's service classifications.

Accordingly, we specifically find that it is just and reasonable to implement the $ 595,000 rate increase in the manner that has been jointly proposed here. [*12] This amount of additional revenue has been justified by St. Lawrence to cover its reasonable costs and expenditures, and to sustain its services and operations. The results of Staff's audit and investigation also warrant our setting the rate increase at the more modest level that will remain in effect for the next three years.

The Joint Proposal also contains other features that serve customers and the public interest. Its service quality provisions assure customers of the best service the company can provide. They hold St. Lawrence to established service levels, promote customer satisfaction and avoid complaints being made to the Commission. The Joint Proposal also supports the implementation of a new bill system that will support competitive opportunities and customer choice. Also, St. Lawrence will use outreach and education opportunities to enhance customer awareness of available market choices.

Finally, the Joint Proposal's financial provisions are acceptable. An allowed return on equity of 9.8% is reasonable in the circumstances presented here. It is also reasonable to implement an equal sharing with ratepayers of any earnings the company may achieve over 10.1% during the term [*13] of this rate plan.

The Commission orders:

1. The terms, conditions and provisions of the St. Lawrence Gas Company, Inc. Joint Proposal attached to this order are adopted and made a part of this order.

2. St. Lawrence Gas Company, Inc. is directed to file with the Acting Secretary of the Commission, and to serve all parties, the tariff amendments necessary to implement the requirements of this order by no later than August 27, 2003 to become effect on September 1, 2003. The company is also directed to take all other action necessary to implement the requirements of this order. Any comments on the proposed tariff amendments must be received at the Commission's office within ten days of service of the tariff amendments. The amendments shall not become effective on a permanent basis until approved by the Commission.

3. The requirement of the Public Service Law that newspaper publication be completed prior to the effective date of the amendments is waived, but the company is directed to file with the Commission, not later than six weeks following the effective date of the amendments, proof that a notice of the changes set forth in the amendments and their effective date has been [*14] published for four consecutive weeks in a newspaper having general circulation in the service territory of the company.

4. St. Lawrence Gas Company, Inc. is directed to cancel, effective no later than August 27, 2003, the following tariff amendments and supplements:

Amendments to Schedule P.S.C. No. 2 - Gas

First Revised Leaf No. 45-Q

Third Revised Leaf No. 28A-3

Fourth Revised Leaf No. 50-B1, 54-D

Eighth Revised Leaves Nos. 28-D, 59, 65

Ninth Revised Leaves Nos. 46-B, 50-C

Tenth Revised Leaves Nos. 22, 24, 50-B

Eleventh Revised Leaves Nos. 54-C, 58-A

Thirteenth Revised Leaf No. 25

Fourteenth Revised Leaf No. 48

Fifteenth Revised Leaves Nos. 55, 57

Nineteenth Revised Leaf No. 30

Twentieth Revised Leaf No. 47

Supplement Nos. 57, 58 and 59 to Schedule P.S.C. No. 2 -Gas

5. St. Lawrence Gas Company, Inc.'s request for waivers of the 150-day provision of the policy statement adopted in Case 26821 is granted.

6. Case 02-G-1275 is continued. Case 02-G-1011 is closed.

ATTACHMENT

STATE OF NEW YORK PUBLIC SERVICE COMMISSION

CASE 02-G-1275 - Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of St. Lawrence Gas Company, Inc. for Gas Service.

CASE 02-G-1011 [*15] - Petition of St. Lawrence Gas Company, Inc. for a Waiver of the 150-Day Provision of the Commission's Statement of Policy on Test Periods in Major Rate Proceedings, filed in C 26821.

JOINT PROPOSAL TO NEW YORK STATE PUBLIC SERVICE COMMISSION

Case 02-G-1275 and 02-G-1011 - Gas Rate Joint Proposal

I. BACKGROUND

On September 27, 2002, St. Lawrence Gas Company, Inc. ("St. Lawrence" or the "Company") filed with the New York State Public Service Commission (the "Commission") revised rates designed to recover $ 1,713,400 of increased revenues. In support of its proposed rates, the Company filed testimony of seven witnesses, along with supporting schedules and exhibits. In this filing, St. Lawrence made various accounting and rate change proposals and cost of service adjustments.

In accordance with Commission rules, all parties to this proceeding were notified in writing of the pendency of negotiations, prior to their commencement, and notice of the impending negotiations was duly filed with the Secretary of the Commission by letter dated on January 7, 2003.

Negotiations took place in Albany over several days in February, 2003 and March, 2003. On February 25, 2003, the Company [*16] agreed with the other parties to an extension of the period which the proposed rates' effectiveness would be suspended until September 26, 2003. The parties, with the assistance of a mediator from the Department's Office of Hearings and Alternative Dispute Resolution, reconvened and continued negotiations on March 10-12, 2003. An agreement in principle was reached among the parties on March 12, 2003. The parties again reconvened on March 20, 2003 by teleconference to discuss rate design issues, at which time they reached general agreement in principle, subject to production of schedules showing various rate impacts. The Signatory Parties (Staff, Alcoa, Inc., Multiple Intervenors (an

Tab P

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

June 25, 2004

IN RE:	)	
	)	
PETITION OF TENNESSEE AMERICAN WATER COMPANY TO CHANGE AND INCREASE CERTAIN RATES AND CHARGES SO AS TO PERMIT IT TO EARN A FAIR AND ADEQUATE RATE OF RETURN ON ITS PROPERTY USED AND USEFUL IN FURNISHING WATER SERVICE TO ITS CUSTOMERS	))))))	**DOCKET NO. 03-00118**

FINAL ORDER APPROVING RATE INCREASE AND RATE DESIGN AND APPROVING RATES FILED BY TENNESSEE AMERICAN WATER COMPANY

This matter came before Director Pat Miller, Director Sara Kyle, and Director Ron Jones, of the Tennessee Regulatory Authority ("Authority" or "TRA"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on August 4, 2003, for consideration of the *Petition of Tennessee American Water Company to Change and Increase Certain Rates and Charges so as to Permit It to Earn a Fair and Adequate Rate of Return on Its Property Used and Useful in Furnishing Water Service to Its Customers* ("*Petition*") filed on February 7, 2003. As more fully described herein and for the reasons set forth below, a majority of the panel voted to grant the request of Tennessee American Water Company ("TAWC" or the "Company") to increase its rates. Additionally, a majority of the panel voted to approve a rate design implementing the increased rates. At an Authority Conference held on August 18, 2003, the revised rates were put into effect according to the tariff filed by TAWC on August 5, 2003.

Background

Authority's September 26, 2000 Order in TRA Docket No. 99-00891

On October 25, 1999, TAWC and the City of Chattanooga ("Chattanooga") entered into a settlement agreement of a previously-filed condemnation lawsuit[1] wherein Chattanooga sought to acquire certain assets of TAWC. Section 2.B of the settlement agreement stated as follows:

> [The Company] and the City will file a joint petition with the Tennessee Regulatory Authority ("TRA") seeking permission to reduce over a two-year period the current charge of $301.00 a year per fire hydrant to $50.00 a year per fire hydrant at the end of that period. If the TRA does not approve this provision, then this section is null and void.

In accordance with the settlement agreement TAWC submitted a tariff filing to the Authority for approval. TAWC's filing was submitted on November 17, 1999 and was assigned Docket No. 99-00891. Through the tariff filing, TAWC proposed to decrease, in quarterly reductions, its annual charges to Chattanooga for fire hydrants from the rate of $301.20 per hydrant to a reduced rate of $50.00 per hydrant. At the time of the tariff filing, TAWC provided 4,491 fire hydrants to Chattanooga and surrounding areas. According to TAWC, the reductions would result in an annual revenue impact of negative $1,127,964.[2]

TAWC's tariff filing was considered by the TRA at a regularly scheduled Authority Conference held on January 11, 2000. At that Conference, a majority[3] of the Directors voted to approve the proposed reduction in annual fire hydrant charges to Chattanooga and ordered that

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[1] *See City of Chattanooga v Tennessee-American Water Company et al*, Case No 99-C-1081, Circuit Court of Hamilton County, Division IV

[2] *See In re. Tariff Filing to Reduce Fire Hydrant Annual Charges as Part of a Settlement Agreement Between the City of Chattanooga and Tennessee-American Water Company*, Docket No 99-00891, Company's Response to Authority Data Request, December 20, 1999, Attachment A

[3] Director Lynn Greer voted not to approve the tariff Director Greer did, however, state, "I do strongly agree though with Chairman Malone's portion of his motion that says that he believes the ratepayers should not bear any cost in any future rate case I strongly support that decision " *See In re Tariff Filing to Reduce Fire Hydrant Annual Charges as Part of a Settlement Agreement Between the City of Chattanooga and Tennessee-American Water Company*, Docket No 99-00891, Transcript of Authority Conference, p. 27 (January 11, 2000)

the reduction be borne by the stockholders of TAWC and not by the Company's ratepayers.[4] In its Order approving TAWC's tariff filing, the Authority recognized that the lost revenues would be imputed into TAWC's subsequent rate filings, thus reflecting the decision of the Company and its stockholders to absorb the contribution loss.[5] The Order specifically stated:

> The Company's ratepayers shall not at any time, through increases in rates, fees, schedules or otherwise, bear any of the cost resulting from this Tariff filing by Tennessee-American Water Company to voluntarily reduce its fire hydrant charges to the City of Chattanooga.[6]

Paragraph 2 of the ordering clauses required the following:

> 2. The lost contribution to Tennessee-American Water Company resulting from the reduction in fire hydrant charges along with any expenses incurred as a result of the underlying litigation with the City of Chattanooga shall be borne, in full, by the stockholders of Tennessee American Water Company;

The Authority's Order became final after no party or person sought reconsideration or appeal.

<u>Travel of this Case (Docket No. 03-00118)</u>

<u>TAWC's *Petition*</u>

TAWC filed its *Petition* for a rate increase in this docket on February 7, 2003. Through its *Petition* TAWC sought TRA approval of an increase in annual revenues of $3,866,813 and an overall rate of return of 8.559 percent (8.559%) with an 11.00 percent (11%) return on equity during the attrition year ending March 31, 2004. In the proposed tariffs filed by TAWC, the additional annual revenues would be recovered by increased charges to all classes of customers.

In support of its *Petition*, TAWC filed sworn testimony, together with exhibits, of the following witnesses: Michael A. Miller, Vice President and Treasurer/Comptroller of TAWC; Roy L. Ferrell, Sr.; Paul Moul, managing consultant; Sheila A. Valentine, Senior Financial

[4] *See In re: Tariff Filing to Reduce Fire Hydrant Annual Charges as Part of a Settlement Agreement Between the City of Chattanooga and Tennessee-American Water Company*, Docket No 99-00891, *Order Approving Tariff*, p 5 (September 26, 2000) (hereinafter *Order Approving Tariff*)
[5] *Order Approve Tariff*, p. 3, n 6
[6] *Id* at 5.

Analyst for TAWC; Monty Bishop, TAWC Operations Manager; Paul R. Herbert, Vice President, Gannett Fleming, Inc.; James E. Salser, consultant; Edward Spitznayle, Ph.D.; and William L'Ecuyer, President of TAWC. TAWC also filed proposed tariff revisions reflecting changes and increases to rates and charges by the Company.

Chattanooga and the Consumer Advocate and Protection Division of the Office of the Attorney General ("Consumer Advocate") each filed a petition to intervene on February 25, 2003. The Chattanooga Manufacturers Association ("CMA") filed a petition to intervene on February 26, 2003.

TAWC's *Petition* was considered at a regularly scheduled Authority Conference held on March 3, 2003, at which time the panel voted unanimously to suspend TAWC's proposed tariff and to appoint Director Ron Jones as the Hearing Officer for the purpose of preparing this matter for Hearing.[7] The Hearing Officer held a Status Conference on March 12, 2003 at which time the petitions to intervene were granted, without objection. From that Status Conference an Order was issued on March 17, 2003, in which the Hearing Officer established a procedural schedule for discovery and the filing of testimony and set this matter for Hearing on June 30 and July 1, 2003.

The parties conducted discovery in the form of interrogatories and requests for production of documents pursuant to the Hearing Officer's procedural schedule.[8] Thereafter, the intervening parties submitted pre-filed testimony as follows: the Consumer Advocate filed the direct testimony of Michael D. Chrysler, Mark H. Crocker and Steve N. Brown, Ph.D.; CMA filed the direct testimony of Michael Gorman, consultant; Randy Crowder, Quality Assurance

[7] In appointing Director Jones as the Hearing Officer in this docket, the panel acknowledged that a contested case was being convened in accordance with Tenn Code Ann. § 65-5-203.
[8] The original procedural schedule was subsequently amended by an order entered by the Hearing Officer on June 12, 2003.

Manager for Bob Stowe Mills, Inc.; Ray Childers, President, Chattanooga Manufacturers Association; Dan Nuckolls, Operations Director for Koch Foods, LLC; and Craig Cantrell, Plant Manager for Velsicol Chemical Corporation; and Chattanooga filed the direct testimony of Jon Kinsey, former Mayor of Chattanooga; Daisy Madison, Treasurer and Deputy Finance Officer for Chattanooga; Jim Mac Coppinger, Fire Chief for Chattanooga; and Marlin L. Mosby, Jr., financial consultant. Rebuttal testimony of Dr. Brown and Mr. Gorman was filed by the Consumer Advocate and CMA, respectively. TAWC filed rebuttal testimony of Michael Miller, Paul Moul, Paul Herbert and Chris Klein, Ph.D.[9]

On June 27, 2003, TAWC and the Consumer Advocate filed with the Authority a *Proposed Settlement Agreement ("Agreement")* relating to specific issues and in which those parties stipulated to the following:

1. That Tennessee-American is entitled to earn a 7.73% return on investments with a 9.9% return on equity, as shown in attached Schedule 1.

2. The Attorney General and Tennessee-American further stipulate and agree that a 7.73% return on investment generates a revenue deficiency of either: (1) $1,617,447 in the event the Tennessee Regulatory Authority continues to impute the reduction of the fire hydrant annual charges as ordered by the TRA in its response to the Company's petition to voluntarily reduce its annual price for public fire service from $301.20 to $50 per public fire hydrant, in TRA Docket No. 99-00891; or (2) $2,745,411 in the event the TRA decides to reverse the imputation of the fire hydrant annual cost or otherwise approve an overall settlement with an adjustment that would offset the loss in public fire service revenues. The revenue deficiency with and without the imputation of the fire hydrant annual cost is shown in Schedule 2.[10]

[9] Dr Klein's testimony was stricken upon the Motion of the Consumer Advocate *See Order Granting Motion to Strike* (June 27, 2003)
[10] *Proposed Settlement Agreement*, pp. 1-2 (June 27, 2003)

The Hearing

The Hearing in this matter was held before the voting panel on June 30 and July 1, 2003. Participating in the Hearing were the following parties and their respective counsel:

> **Tennessee American Water Company** - T. G. Pappas, Esq. and R. Dale Grimes, Esq., Bass, Berry and Sims, PLC, 315 Deaderick Street, AmSouth Center, Suite 2700, Nashville, Tennessee 37238-3001;
>
> **Consumer Advocate and Protection Division** - Vance Broemel, Esq. and Shilina B. Chatterjee, Esq., Office of the Attorney General, P.O. Box 20207, Nashville, Tennessee 37202;
>
> **Chattanooga Manufacturers Association** - Henry Walker, Esq., Boult, Cummings, Conners & Berry, PLC, 414 Union Street, Suite 1600, Nashville, Tennessee 37219 and David C. Higney, Esq., Grant, Konvalinka & Harrison, P.C., 633 Chestnut Street, 9th Floor, Chattanooga, Tennessee 37450; and
>
> **City of Chattanooga, Tennessee** - Michael A. McMahan, Esq. and Phillip A. Noblett, Esq., Special Counsel, 801 Broad Street, Suite 400, Chattanooga, Tennessee 37402.

At the outset of the Hearing, the attorneys for Chattanooga and the CMA each expressed their respective clients' support for the *Agreement*.[11] After hearing from all of the parties, the panel voted unanimously to accept the *Agreement*.[12] By acceptance of the *Agreement*, the Authority determined the rate base to be $87,062,756, the return on investment to be 7.73% and the return on equity to be 9.9%. Approval of the *Agreement* also removed from the proceeding the issues relating to the cost of capital, revenues and expenses.

Thereafter, during the Hearing, the parties reached an additional agreement identifying an appropriate rate design for use in the event that the Authority determined the revenue deficiency to be $1,617,447. This rate design was set forth in Exhibit 3 received into the record during the Hearing. All of the parties did not reach an agreement as to an appropriate rate design in the

[11] Transcript of Proceedings, Vol I, p. 11 (June 30, 2003).
[12] *Id* at 44.

event that the Authority determined a revenue deficiency in any other amount.[13] Nevertheless, a rate design was entered into the record as Exhibit 4 that reflected a model breakdown of rates per customer classification in the event the revenue deficiency was determined to be $2,745,411.[14]

Upon the acceptance of the *Agreement,* the Authority articulated the two issues remaining for determination as: the question of continued imputation of the reduction of fire hydrant charges and the appropriate rate design for implementing the rate increase.

Acceptance of the *Agreement* eliminated the need for live testimony from all of the witnesses who submitted pre-filed testimony; however, without objection from the parties, the panel voted unanimously to admit into the evidentiary record the pre-filed direct and rebuttal testimony of all witnesses, with the exception of Dr. Chris Klein whose testimony was excluded by order of the Hearing Officer.[15] The panel heard live testimony from certain witnesses on the issues of the imputation of fire hydrant revenues and rate design. Counsel for TAWC called Michael Miller and Paul Herbert as witnesses. The Consumer Advocate called Dr. Steve Brown as its witness. Counsel for Chattanooga called Daisy Madison and Ray Childers as its witnesses. CMA called Michael Gorman as a witness. All witnesses were subject to cross examination by the parties and questions from members of the voting panel. Rebuttal testimony was heard on July 1, 2003. In rebuttal, TAWC called Michael Miller. Chattanooga called Jim Mac Coppinger and Jon Kinsey. At the conclusion of the testimony, the panel ordered that post-hearing briefs be filed addressing the imputation of fire hydrant revenues and rate design. The parties filed post-hearing briefs on July 11, 2003.

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[13] *Id* at 46

[14] *Id*

[15] *Order Granting Motion to Strike* (June 27, 2003).

POSITIONS OF THE PARTIES

TAWC

Through testimony and its post-hearing brief, TAWC has asserted the following: the disallowance of $1.1 million of the established $2.7 million revenue requirement would unconstitutionally prevent TAWC from earning its approved rate of return on its approved reasonable rate base; the prior Order in Docket No. 99-00891 does not require a $1.1 million reduction of TAWC's approved revenue requirement; ordering TAWC to write off a portion of its assets in order to give the appearance that it is achieving its approved rate of return is inappropriate; and, even if the TRA in Docket No. 99-00891 ordered TAWC never to recover the cost of its fire protection service in a future rate case, the TRA is entitled to and should decline to follow that Order in this case.

TAWC argued that, under the facts and circumstances presented, a rate increase is warranted because the Company is entitled to a fair rate of return on all of its investment either used and useful in the provision of service to its customers.[16] TAWC argued that, considering the stipulated rate base of $87,062,756 and the stipulated rate of return on investments of 7.73 percent (7.73%) with a 9.9 percent (9.9%) return on equity, the stipulated revenues of the Company produce a revenue deficiency of $2,745,411.[17] TAWC further argued that the disallowance of $1.1 million of the established $2.7 million revenue requirement would prevent TAWC from earning its approved rate of return on its approved reasonable rate base, thereby resulting in an unconstitutional taking of property.[18]

In addressing the Authority's Order in Docket No. 99-00891, TAWC argued that the Order would not preclude the Company from recovering its full revenue requirement in this

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[16] *Petitioner Tennessee American Water Company's Post Hearing Brief*, p 4 (July 11, 2003).
[17] *Id* at 5-6
[18] *Id* at 6.

matter or require a reduction of the $1.1 million in that revenue requirement in perpetuity.[19] TAWC stated that the Order in Docket No. 99-00891 only prohibits the Company from recovering from ratepayers the actual revenues lost by the reduction in the fire hydrant rate to Chattanooga.[20]

TAWC witness Miller testified that in agreeing to a reduction of fire hydrant revenues, "the Company was only referring to the stub period between the tariff date and the rate hearing sometime in the future and was not agreeing to any permanent reduction in its otherwise approved revenue requirement."[21] TAWC stated that it is not attempting to recover loss of revenue from the reduction in the fire hydrant rate to Chattanooga, which occurred during the "stub period."[22] The Company maintained that the Authority's Order in Docket No. 99-00891, if interpreted as the imputation of the hydrant revenue "in perpetuity," would "equate to untold millions" in lost revenue and "place the Company in a position where it would not have an opportunity in this case or any future rate cases to achieve a fair and reasonable return on its investments."[23]

The Company argued that even other parties in Docket No. 99-00891 understood the agreement to be only temporary, or during a certain time period until TAWC files for a rate case. In this regard, the Company relied on the statements in the record of Docket No. 99-00891 made by Chattanooga's attorney and the Mayor of Chattanooga at the time, Mr. Kinsey.

In opposition to a proposal offered by CMA witness Michael Gorman, TAWC responded that ordering the Company to write off a portion of its assets in order to give the appearance that

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[19] *Id* at 9.
[20] *Id* at 10.
[21] According to TAWC, "[t]he stub period was the period between the effective date of the tariff reducing the fire hydrant rate over a two-year period and the time this Authority approves new rates in the Company's subsequent rate case " Transcript of Proceedings, Vol I , pp 63-63 (June 30, 2003)
[22] *Petitioner Tennessee American Water Company's Post Hearing Brief*, p 10 (July 11, 2003).
[23] Pre-filed Rebuttal Testimony of Michael A Miller, pp 19-20 (June 23, 2003)

it is achieving its approved rate of return would be inappropriate and would amount to a confiscation of its assets.[24]

In its post hearing brief, TAWC stated that it did not oppose either the rate design set forth in Exhibit 3 reflecting the $1,617,447 revenue increase or the rate design in Exhibit 4 reflecting the $2,745,411 revenue increase.[25] Nevertheless, TAWC argued that the Company is entitled to an increase in rates to allow it to recover $2,745,411 and that Exhibit 4 provides the appropriate rate design for allocating that rate increase.

Chattanooga

Chattanooga argued in its post hearing brief that TAWC voluntarily waived any claim that it might otherwise have to the approximately $1.1 million in revenues for fire protection services, which represents the difference between the proposed rate increases of $2,745,411 and $1,617,447, when TAWC and Chattanooga voluntarily entered into the settlement agreement resolving Chattanooga's condemnation action to acquire TAWC's assets.[26] Chattanooga argued further that the TRA properly held that the $1.1 million loss in revenue should be borne by TAWC's stockholders.[27]

With regard to rate design, Chattanooga stated that the rate design set forth in Exhibit 3 reflecting the $1,617,447 rate increase fulfills the revenue requirements of TAWC and properly puts the loss of the fire hydrant revenue on TAWC's stockholders.[28] In the alternative, Chattanooga argued that should the panel determine to allow a revenue increase of $2,745,411 then the rate design set forth in Exhibit 4 is properly supported by the record in this matter.[29]

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[24] TAWC assumes that it would have to write-off $8 0 to $10 0 million of assets that would still be used and useful in providing services

[25] *Petitioner Tennessee American Water Company's Post Hearing Brief*, p 18 (July 11, 2003).

[26] *Post Hearing Brief of City of Chattanooga*, p 15 (July 11, 2003)

[27] *Id*

[28] *Id.*

[29] *Id* at 16

Consumer Advocate

The Consumer Advocate argued that a TRA decision in this docket to uphold the Order in Docket No. 99-00891 and continue the $1.1 million fire protection reduction would not prohibit TAWC from earning a fair rate of return. According to the Consumer Advocate, there was no conclusive proof that the residential and commercial customers were not paying their full share of costs. The study on which TAWC witness Herbert relied for his "cost causer" opinion did not use studies of actual loads placed on the system by classes of customers.[30] Instead, the witness relied upon data from out-of-state water companies without any proof that these companies served cities with loads similar to Chattanooga. The Consumer Advocate also pointed out that residential and commercial consumers were never a part of the settlement arrangement between TAWC and Chattanooga concerning the fire hydrant fees.[31]

In its post hearing brief, the Consumer Advocate restated its agreement that the revenue deficiency for TAWC is either $1,617,447 in the event that the TRA continues to impute the reduction of fire hydrant revenue or $2,745,411 in the event that the TRA decides to no longer impute the reduction of the fire hydrant revenue.[32] The Consumer Advocate asserted its support for the rate design set forth in Exhibit 3 reflecting the $1,617,447 rate increase and argued that the TRA should adopt this rate increase rather than the $2,745,411 increase. The Consumer Advocate objected to the rate design set forth in Exhibit 4 reflecting the $2,745,411 increase on the basis that the rate design would produce an unacceptable rate increase for consumers by shifting the approximately $1.1 million of fire protection costs to residential and commercial customers.[33]

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[30] Transcript of Proceedings, Vol. I, pp 120-121 (June 30, 2003)
[31] *Consumer Advocate's Post-Hearing Brief*, p 6 (July 11, 2003).
[32] *Id* at 3
[33] *Id* at 4.

CMA

CMA asserted the position that the TRA's Order in Docket No. 99-00891 clearly meant that the lost revenue resulting from the reduction in fire hydrant charges shall be borne, in full, by the stockholders and that the Company's ratepayers shall not at any time bear any of the cost resulting from the tariff filing by TAWC to voluntarily reduce its fire hydrant charges to Chattanooga.

In its post-hearing brief, CMA focused on the issue of whether the Authority should continue to impute the lost fire hydrant revenue and argued that TAWC's stockholders should continue to absorb the costs associated with lost fire hydrant revenues. For that reason, CMA supported the adoption of the rate design agreed to and set forth in Exhibit 3.[34]

CMA witness Michael Gorman testified that the TRA's decision to reduce hydrant rates does not mean that the Company will never have the opportunity to earn a fair return. He explained that the Company has options such as (1) a write off of the value of its Tennessee assets to reflect the fact that the Company is no longer allowed to earn a return on a portion of its assets,[35] (2) an equity infusion from the parent company to cure the credit rating, or (3) a suspension of dividend payments to the stockholders to restore the common equity balance.[36]

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[34] *Post Hearing Brief of Chattanooga Manufacturers Association*, p 5 (July 11, 2003)
[35] According to TAWC, if writing off its assets was an option, the Company would write off about $8 to $10 million worth of assets. Transcript of Proceedings, Vol II, p 187 (July 1, 2003)
[36] Transcript of Proceedings, Vol I, pp 146-147 (June 30, 2003)

Findings And Conclusions

Except for the issues relating to the restoration of the Company's voluntary rate reduction to Chattanooga in Docket 99-00891 and rate design in this docket, the parties were able to reach a resolution to settle all other issues in this case. While Chattanooga and the CMA were not signatory parties to the *Agreement*, both parties stated, at the Hearing, their acceptance of the terms of the *Agreement*. Upon consideration of the entire record, including all exhibits and the briefs of the parties, the panel made the following findings and conclusions.

Restoration of the Voluntary Rate Reduction for Public Fire Protection Service to Chattanooga

In Docket No. 99-00891, the TRA approved the tariff filing by the Company that voluntarily reduced rates to Chattanooga by $1,127,964 per year for public fire protection service. As part of its *Petition*, TAWC requested the TRA reinstate this revenue stream. The parties to this case were unable to reach a settlement on this issue.

In issuing the Authority's Order in Docket No. 99-00891, the TRA Directors were unanimous in their position that the ratepayers of TAWC should not bear the cost of the fire hydrant rate reduction.[37] The Tennessee Court of Appeals has recognized that an agency may change its position over time regarding whether a matter is best in the public interest. In *Alltel Tennessee, Inc. v. Tennessee Public Service Commission*, the Tennessee Court of Appeals held that the Tennessee Public Service Commission ("TPSC") would not be "barred by stare decisis," provided that the TPSC did not act arbitrarily in changing from an established rule.[38]

The evidence in the record of this docket clearly demonstrates that the Company's intentions "to recover the lost margin resulting from the approval of [the] Tariff by increasing

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[37] *Order Approving Tariff*, p 4, n.8.

[38] *Alltel Tennessee, Inc v Tennessee Public Service Commission*, No 89-298-II, 1990 WL 20132 (Tenn Ct App March 7, 1990) The Court stated that an agency decision would not be considered arbitrary if a reasoned explanation is provided along with the change of policy. *Id* at *3

sales of water to existing customers and by gaining new customers"[39] did not completely come to fruition. In addition, the Company suffered other expenses and revenue reductions over the past three years since the approval of the tariff.

In determining whether TAWC should receive all or part of the revenue requirement that it seeks, the Authority need not base its decision on an interpretation of the Order in Docket No. 99-00891. Notwithstanding the clear objective of the Order in Docket No. 99-00891 of imputing lost revenues to the shareholders, the Authority finds little support today for continuing this imputation in perpetuity.

The Authority is obligated to balance the interests of the utilities subject to its jurisdiction with the interests of Tennessee consumers, i.e., it is obligated to fix just and reasonable rates.[40] The Authority must also approve rates that provide regulated utilities the opportunity to earn a just and reasonable return on their investments.[41] Allowing a perpetual imputation of revenues lost from the reduction to fire hydrant rates would prevent the Authority from meeting these requirements. Such an imputation denies TAWC a fair return on its assets that are used and useful in the provision of water and public fire protection service to the ratepayers in Chattanooga. Consistent with the Authority's Order in Docket No. 99-00891 approving the reduction of fire hydrant rates, TAWC has foregone more than $3 million in revenues from the time it resolved the condemnation lawsuit with Chattanooga. Likewise, Chattanooga has directly benefited from this $3 million dollar reduction in charges paid to TAWC.[42]

While the record contains no evidence necessitating a modification of the Order in Docket No. 99-00891, there is evidence today to support the Company's claim that additional

[39] *Order Approving Tariff* at 3.
[40] Tenn Code Ann § 65-5-201 (Supp 2002)
[41] *See Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia*, 262 U.S. 679, 43 S Ct. 675 (1923)
[42] Director Jones's vote was not based on a finding related to TAWC's foregone revenues or the benefit thereof to Chattanooga.

revenue requirement may be necessary. For these reasons, a majority of the panel found that the imputation of reduced fire hydrant rates to Chattanooga should be discontinued.

Criteria for Establishing Just and Reasonable Rates

The Authority considers petitions for a rate increase, filed pursuant to Tenn. Code Ann. § 65-5-203, in light of the following criteria:

1. The investment or rate base upon which the utility should be permitted to earn a fair rate of return;
2. The proper level of revenues for the utility;
3. The proper level of expenses for the utility; and
4. The rate of return the utility should earn.

The general standards to be considered in establishing the costs of common equity for a public utility are financial integrity, capital attraction and setting a return on equity that is commensurate with returns investors could achieve by investing in other enterprises of corresponding risk. The utility's cost of common equity is the minimum return investors expect, or require, in order to make an investment in the utility. The proper level of return on the Company's capital, including equity capital, must allow a return on capital that is commensurate with returns on investment in other enterprises having corresponding risk.[43]

Test Period

The objective of selecting a test period is to obtain financial data and adjust it as necessary to reflect the inter-relationship of revenues, expenses and investment expected to occur in the immediate future. In this case, the Company selected the twelve months ended July 31, 2002, as the historical test period and made two levels of adjustments. The first level of adjustment normalizes the test year and the second adjusts the normalized year to arrive at the

[43] *See Federal Power Commission v Hope Natural Gas Co*, 320 U S 591, 64 S Ct 281 (1944)

forecast for the attrition year, which is the twelve months ending March 31, 2004. In adopting the *Agreement* between the parties, the panel found that the test period as adjusted will provide the Company the opportunity to earn a fair rate of return on its investment.

Rate Base

Through the *Agreement*, the parties stipulated to a rate base for the attrition year of $87,062,756 as detailed below. The TRA found that the rate base in this case has been adjusted to reflect the investment and expenses of the Company for the attrition year test period and therefore is proper and should give the Company the opportunity to earn a fair rate of return on its investment to which it is entitled.

Additions:	
Utility Plant in Service	$146,234,775
Construction Work in Progress	801,659
Utility Plant Capital Lease	1,590,500
Limited Term Utility Plant – Net	-20,953
Working Capital	1,403,079
RWIP/Deferred Maintenance	34,191
Total Additions	**$150,043,251**
Deductions:	
Accumulated Depreciation	$44,221,915
Accumulated Amortization of Utility Capital Lease	565,511
Accumulated Deferred Income Taxes	11,070,493
Customer Advances for Construction	2,007,438
Contributions in Aid of Construction	5,064,245
Unamortized Investment Tax Credit	50,893
Total Deductions	**$62,980,495**
Rate Base	**$87,062,756**

Revenues and Expenses

The parties stipulated to certain facts derived from a review and investigation of the Company's books and records for the purposes of this case. The parties agree that the net operating income at present rates of the Company for the attrition period is $5,098,465 as detailed below. The TRA finds that the net operating income in this case has been adjusted to reflect the appropriate attrition period level of revenues and expenses necessary for continued utility operations.

Revenues:	
Sales of Water	$28,952,398
Other	806,059
Forfeited Discounts	282,161
Total Revenues	**$30,040,618**
Expenses:	
Operation & Maintenance	$16,145,398
Depreciation & Amortization	4,121,753
Taxes Other Than Income	3,430,304
State Excise Tax	126,131
Federal Income Tax	1,170,306
Total Expenses	**$24,993,892**
Allowance for Funds Used During Construction	**$51,739**
Net Operating Income	**$5,098,465**

Fair Rate of Return

In determining a fair rate of return, the Authority must conduct an in-depth analysis and give proper consideration to numerous factors, such as capital structure, cost of capital and changes which can reasonably be anticipated in the foreseeable future. The Authority has the obligation to make this determination based upon the controlling legal standard set forth in the landmark cases of *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*[44] and *Federal Power Commission v. Hope Natural Gas Company,*[45] which have been specifically relied upon by the Tennessee Supreme Court.[46] In the *Bluefield* case, the United States Supreme Court stated:

[44] *Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia*, 262 U.S. 679, 43 S Ct. 675 (1923).
[45] *Federal Power Commission v Hope Natural Gas Company*, 320 U S. 591, 64 S Ct 281 (1944)
[46] *Southern Bell Telephone & Telegraph Co v Public Service Commission*, 304 S W 2d 640, 647 (1957).

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risk and uncertainties; but it has no constitutional rights to profits such as are realized or anticipated in highly profitable or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[47]

Later, in the *Hope* case, the United States Supreme Court refined these guidelines, holding that:

> From the investor or company points of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and to attract capital.[48]

The parties, for the purposes of this case, have agreed on a capital structure and cost that produces an overall rate of return for the Company of 7.73% as detailed below. After reviewing the necessary factors, the TRA found that this rate of return is fair and reasonable and meets the tests articulated in the *Bluefield* and *Hope* cases.

	Ratio	Cost Rate	Weighted Cost Rate
Parent:			
Debt	56.00%	9.90%	5.54%
Common Equity	44.00%	6.00%	2.64%
Total	**100.00%**		**8.18%**
Tennessee-American			
Short Term Debt	6.20%	3.50%	0.22%
Long Term Debt	20.80%	7.62%	1.59%
Preferred Stock	1.60%	5.01%	0.08%
Common Equity	71.40%	8.18%	5.84%
Total	**100.00%**		**7.73%**

[47] *See Bluefield Water Works and Improvement Company v Public Service Commission of the State of West Virginia*, 262 U S 679, 43 S.Ct. 675 (1923).
[48] *Federal Power Commission v Hope Natural Gas Company*, 320 U S 591, 603 (1944)

Revenue Deficiency

Based upon the rate base, net operating income, and fair rate of return agreed to by the parties, the TRA found that the revenue deficiency for this case should be calculated to be $2,745,411 as shown below. The TRA therefore found that the Company needs additional annual revenues in the amount of $2,745,411 in order to earn a fair return on its investment during the attrition year.

Rate Base	$87,062,756
Fair Rate of Return	7.73%
Required Net Operating Income	**$6,729,951**
Current Net Operating Income	5,098,465
Net Operating Income Deficiency	$1,631,486
Retention Factor	1.682767
Total Revenue Deficiency	**$2,745,411**

Rate Design

It is clear from the testimony of the TAWC witnesses and statements by their counsel that the Company desired to move more toward a rate design that would reflect the "cost causer" principle. The company witnesses and the CMA witness all agree that fire protection rates are not covering their costs as developed by Mr. Herbert. The proposed tariff for fire protection covers only 25% of the cost of that service. No other class of customer receives such a large discount. The witnesses all agree that the cost of fire protection is between $313 and $316 per hydrant. This approximates the rate that was charged for fire protection ($301 per hydrant) prior to the voluntary rate reduction put into effect by TAWC to settle the condemnation proceeding. Because the goal of the fire hydrant tariff reduction was to settle the condemnation proceeding between Chattanooga and TAWC, all of the benefits flowed to those two parties during the time the reduced revenue tariff has been in place.[49] Chattanooga has also benefited from the circumstance that there has not been an adjustment to water rates in Chattanooga since November 1, 1996.[50]

Through the Agreement in this docket, the parties reached a settlement that included a rate design that will produce additional revenues of approximately $1,617,447 as shown below. This amount does not include revenues from public fire protection service in an amount of $1,127,964.

	Total Revenues	Rate Increase %	Rate Increase
Residential	$12,026,923	5.5866%	$671,893
Commercial	9,180,456	5.5866%	512,873
Industrial	3,169,070	4.3500%	137,855
Other Public Authority	2,345,806	5.5866%	131,050
Other Water Utility	856,218	5.5866%	47,833
Private Fire Service	1,117,875	5.5866%	62,451
Public Fire Service	256,049	20.9000%	53,514
Total	**$28,952,397**	**5.5866%**	**$1,617,469**
Revenue Deficiency			1,617,447
Difference			**$22**

Based upon the record in this matter, a majority of the panel found that it is appropriate to allow the Company to recover the previous voluntary reduction in revenues of $1,127,964, bringing the total revenue deficiency in this case to $2,745,411 ($1,617,447 + $1,127,964). The panel unanimously found that fifty percent (50%) of the restoration of the voluntary rate reduction or $563,982 ($1,127,964 x 50%) should be allocated to Chattanooga for public fire protection service. In addition, a majority of the panel found that the remaining $563,982 from the restoration of the voluntary rate reduction should be allocated to all customer classes, including Chattanooga, using the same rate design, as agreed to by the parties, that produced

[49] Some of the benefit of the reduced fire hydrant expense to the city could have flowed to the taxpayers (ratepayers) through lower tax bills though no evidence was presented to confirm that actually happened.
[50] Chattanooga's water rates were last adjusted by the Authority in Docket No 96-00959

$1,617,447 in additional revenues.[51] This rate design represents an overall increase in rates for all classes of customers. The TRA found that this rate design is just and reasonable and meets the standards set out in Tenn. Code Ann. § 65-5-203(a).

TAWC's Tariff Reflecting Rate Increases and Rate Design

On August 6, 2003, TAWC filed tariffs with the TRA in accordance with the findings and conclusions of the panel that produced a total increase in revenues of approximately $2,745,411, as shown below.

	Total Revenues	Rate Increase %	Rate Increase
Residential	$12,026,923	7.54%	$906,402
Commercial	9,180,456	7.54%	692,058
Industrial	3,169,070	5.89%	186,654
Other Public Authority	2,345,806	7.51%	176,180
Other Water Utility	856,218	7.51%	64,343
Private Fire Service	1,117,875	7.51%	84,006
Public Fire Service	256,049	248.25%	635,631
Total	**$28,952,397**	**9.48%**	**$2,745,274**
Revenue Deficiency			2,745,411
Difference			**-$137**

IT IS THEREFORE ORDERED THAT:

1. The Petition of Tennessee American Water Company is approved based upon the Authority's finding that a rate increase is warranted and that TAWC is entitled to a rate increase of $2,745,411.

2. The rate design, as set forth in Exhibit No. 3 of the evidentiary record, is adopted and shall be used to allocate $1,617,447 of the rate increase.

3. As to the remaining $1,127,964 of the rate increase, the amount of $563,982 shall be recovered directly from the City of Chattanooga through an increase to the fire hydrant rate.

[51] At the August 18, 2003 Authority Conference, Director Jones stated that he was not in agreement with a rate design that did not spread the $563,982 portion of the fire hydrant rate increase to be recovered from seven service categories "equally across all customer classes ratably . i.e , equal to all customers across the board " Transcript of Authority Conference, p. 10 (August 18, 2003)

The amount of $563,982 shall be recovered from each of the seven categories of service identified in Exhibit No. 3, using the same percentages for allocation as agreed by the parties for allocating the proposed rate increase of $1,617,447 in Exhibit No. 3.

4. The allocation of the total rate increase between the seven categories of services shall be as follows: (a) the residential, commercial, other public authority, other water utility and private fire service classes shall each be allocated an overall rate increase of 7.54 percent (7.54%); (b) the industrial service class shall be allocated an overall rate increase of 5.87 percent (5.87%); and (c) the public fire service class shall be allocated a rate increase of 248.44 percent (248.44%).

5. The tariff filed by Tennessee American Water Company on August 6, 2003, is in effect per the terms and conditions of that tariff.

6. Any party aggrieved by the Authority's decision in this matter may file a Petition for Reconsideration with the Authority within fifteen (15) days from the date of this Order.

7. Any party aggrieved by the Authority's decision in this matter has the right of judicial review by filing a Petition for Review in the Tennessee Court of Appeals, Middle Section, within sixty (60) days from the date of this Order.

* * *

Pat Miller, Director[52]

Sara Kyle, Director

Ron Jones, Director

[52] Director Miller declined to vote with the majority granting TAWC a revenue requirement in the amount of $2,745,411 00 for the reasons set forth in the *Dissent of Director Pat Miller* filed herewith Director Miller voted with the majority in approving the rate design as set forth above

Tab Q

DT 02-110

VERIZON NEW HAMPSHIRE

Investigation into Cost of Capital

Order Establishing Cost of Capital

O R D E R N O. 24,265

January 16, 2004

APPEARANCES: Victor D. Del Vecchio, Esq. for Verizon New Hampshire; Swidler Berlin Shereff Friedman, LLP by Philip J. Macres, Esq. and Eric J. Branfman, Esq. on behalf of Freedom Ring Communications, LLC d/b/a BayRing Communications; Laura Gallo, Esq., Kenneth W. Salinger, Esq., and Katherine A. Davenport, Esq. for WorldCom, Inc.(now MCI Communications, Inc.); F. Anne Ross, Esq. for the Office of the Consumer Advocate on behalf of residential ratepayers, E. Barclay Jackson, Esq. for the Staff of the New Hampshire Public Utilities Commission.

I. PROCEDURAL HISTORY

The New Hampshire Public Utilities Commission (Commission) initiated this docket, by Order of Notice dated June 28, 2002, to determine the appropriate cost of capital for Verizon New Hampshire (Verizon) and to examine whether recurring TELRIC[1] rates should be modified to take into account a revised cost of capital. Motions to intervene in the matter were filed by Otel Telekom, Inc.(Otel); Global NAPS, Inc. (Global NAPS); Conversent Communications of New Hampshire, LLC (Conversent); CTC Communications Corporation (CTC), Dieca Communications Inc.

[1] TELRIC, or total element long run incremental cost, has been approved by the Federal Communications Commission (FCC) as the appropriate methodology for establishing rates for unbundled network elements.

d/b/a Covad Communications Company (Covad); Freedom Ring Communications, LLC d/b/a BayRing Communications (BayRing), and WorldCom, Inc. (now MCI Communications, Inc. and herein referred to as MCI). In addition, the Office of Consumer Advocate (OCA) filed its intent to participate on behalf of residential utility consumers pursuant to RSA 363:28,II.

The Commission granted all motions to intervene at the Prehearing Conference held on July 12, 2002. Subsequent to the Prehearing Conference, the parties and Staff met in technical discussions on July 12 and July 18, 2002 regarding the scope of the proceeding. Verizon filed testimony on August 30, 2002, pursuant to the initial procedural schedule.

By Order No. 24,053, on September 16, 2002, the Commission approved the parties' joint proposal for a procedural schedule. As a result of several motions to compel responses to discovery, change filing dates for rebuttal testimony, and clarify the scope of the proceeding, on November 27, 2002, the Commission issued Order No. 24,089 clarifying that this cost of capital investigation pertains both to retail and wholesale rates, addressing the discovery issues, and revising the procedural schedule.

Verizon filed supplemental direct testimony on December 13, 2002. The OCA, BayRing and Conversent (BR/C), and Staff filed direct testimony on January 27, 2003. On March 7, 2003, Verizon filed a Motion to Suspend the Deadline for filing Rebuttal Testimony, on the basis of the Federal Communications Commission's (FCC) announcement of its forthcoming Triennial Review Order (TRO). The Commission denied Verizon's motion, finding that the parties and Staff could request leave to file supplemental testimony on the effect of the FCC order if the order were to issue prior to the hearings in this docket.

The Commission heard this case on April 22 and 23, 2003, at which time the FCC had not issued the anticipated TRO decision. The parties and Staff filed briefs on May 31, 2003. By secretarial letter dated June 9, 2003, the Commission requested that Verizon respond to several post-hearing record requests. Verizon filed its responses on June 19, 2003. By letter dated July 9, 2003, the OCA clarified that its Brief supports the application of a single cost of capital to Verizon as a whole but, in the alternative, recommends a separate cost of capital applicable to the wholesale portion of Verizon's business.

By letter dated September 15, 2003, Verizon requested that the Commission re-open the record, permit the parties and Staff to file supplemental testimony explaining how the FCC's *TRO* (issued August 21, 2003) applies, and schedule hearings on the supplemental testimony. On September 17, 2003, the OCA filed an objected to Verizon's motion; on September 25, 2003, MCI filed an objection to Verizon's motion. The Commission issued Order No. 24,237 on November 7, 2003 denying Verizon's request and taking administrative notice of the *TRO* and of the FCC's Wireline Competition Bureau's subsequent application of the *TRO* to its Virginia Arbitration Order.

II. COST OF CAPITAL METHODOLOGY AND THRESHOLD ISSUE OF WHETHER UNE RATES AND RETAIL RATES SHOULD HAVE SEPARATE COSTS OF CAPITAL

The parties and Staff have all identified values for Verizon's cost of equity and cost of debt, and capital structure. The weighted average cost of capital (WACC) is determined by multiplying the cost of equity by the percentage of equity in the company's capital structure, and adding that number to the cost of debt, similarly multiplied by the percentage of debt in the capital structure.

For determining a cost of equity, the parties and Staff all follow Commission practice in utilizing the Discounted Cash Flow (DCF) method. The DCF formula states that the cost of equity can be expressed as

$$k = \frac{D_0(1+g)}{P_0} + g,$$

where k is the cost of equity, D_0 is the current annual dividend on one share of common stock, P_0 is the current stock price, and g is the anticipated growth rate. The parties and Staff each applied the DCF methodology differently, choosing different values for *g* based on varying theories. They therefore obtained different results. The parties and Staff ascertained different values for the cost of debt and for a capital structure, as well, based upon different assumptions. The differing values for each of these three components resulted in significantly different overall costs of capital. The parties and Staff also differ in the general approach to this particular cost of capital determination, raising an important threshold issue, i.e., whether unbundled network elements (UNEs) and retail rates should have separate costs of capital.

Verizon argues that the increased competitive and regulatory risks it faces in New Hampshire requires a cost of capital that is significantly above the cost of capital required during the company's tenure as a state-sanctioned exclusive monopoly. According to Verizon, the Commission must apply two different standards in order to properly consider the different regulatory contexts in which the cost of capital will be applied. Specifically, Verizon argues, the Commission must apply the FCC's forward-looking TELRIC standard to set a separate cost of capital for wholesale services (i.e., UNEs) and the traditional rate of return standard to set a cost of capital for retail services. Verizon presented evidence in support of a cost of capital of 12.45% for retail ratemaking and a cost of capital of 17.93% for wholesale services.

MCI urges the Commission to set one WACC for Verizon. MCI claims that Verizon's cost of capital should be decreased, based on the record before the Commission that the market cost of capital has declined and interest rates are at near-record lows. According to MCI, Verizon's policy claims that increasing its cost of capital will foster facilities-based competition is unsupported conjecture that does not hold up under scrutiny. MCI argues as follows: First, the FCC determined that CLECs are not required to provide facilities-based services; facilities-based competition is a long term goal but UNE-based competition must precede that goal. Second, the Telecommunications Act of 1996 (TAct) recognizes that Verizon and other Regional Bell Operating Companies (RBOCs) today enjoy benefits gained as a result of monopoly-based economies of scale that will take CLECs time to establish. MCI therefore argues that the Commission should not allow Verizon to utilize this cost of capital docket to collaterally attack the federal plan to foster local competition.

According to MCI, Verizon's entire case is based upon an overstatement of risk in the UNE market. Verizon's assumptions about networks that will be rebuilt and abandoned under TELRIC have no rational basis, MCI claims and, in fact, raised in this docket, albeit by a subsidy from retail consumers. OCA claims that the second, newer, standard would require the Commission to conduct a rate case to determine the appropriate rate bases for retail and UNE ratemaking. The OCA points out that, under this second standard, Verizon would run the risk of under-recovering the costs of providing UNEs and that shareholders would bear any investment recovery shortfall.

The OCA concludes that the Commission should follow the first, more traditional standard with a straight retail rate of return of 8.14% applied to the total rate base. The OCA argues that a blended rate should not be applied because that would result in a windfall for Verizon. On the theory that the assets supporting UNEs are minimal compared to total rate base, the OCA contends that any subsidy from retail ratepayers will be insignificant and is far outweighed by the costs involved to separate Verizon assets.

In the alternative, should the Commission decide that a different cost of capital should be applied to UNE rates, the OCA argues that a more realistic debt-to-equity ratio of 35:65 should be recognized and a forward-looking cost of debt of 6.79% should be applied. The resulting separate cost of capital for UNEs would then be 9.45%, capturing, according to the OCA, the total risk of UNE service.

Staff recommends an overall cost of capital of 8.184% based on its recommended capital structure, cost of debt, and cost of equity. This amount is based upon Staff's conclusion that current market conditions signal an unambiguously low opportunity cost of funds.

Staff's approach to the docket rejects Verizon's arguments that TELRIC principles apply to this case, except possibly with regard to the small portion of Verizon's business that provides wholesale services at TELRIC prices. The traditional rate of return regulation to obtain just and reasonable rates as set out in *Federal Power Commission v. Hope Natural Gas*, 320 U.S. 591, 88 L.Ed. 333, 64 S.Ct. 281 (1944) and *Bluefield Water Works v. West Virginia Pub. Serv. Comm.* 262 U.S. 679, 67 L.Ed. 1176, 43 S.Ct. 675 (1923), (*Hope* and *Bluefield*, respectively), including reliance on book values, will best serve the interest of the New Hampshire public, Staff maintains. Nonetheless, Staff also argues that its cost of capital calculation complies with TELRIC principles to the extent necessary, since the cost of capital is intrinsically forward-looking.

III. POSITIONS OF THE PARTIES AND STAFF

A. CAPITAL STRUCTURE

1. Verizon

Verizon's witness, Dr. Vander Weide, reasons that economic theory and TELRIC principles require the Commission to estimate Verizon's capital structure by using "market value" rather than book value. Verizon recommends the Commission determine a capital structure for the company based upon the average market value capital structure of a proxy group of competitive industrial companies and a group of telecommunications companies with Incumbent Local Exchange Carrier (ILEC) subsidiaries. (Ex. 1 p. 49) Since the average market value capital structure computed by Verizon for the proxy group was no more than 25% debt and 75% equity during the last five years (Ex. 1, Table 2, p. 50), Verizon recommends 25% debt and 75% equity for its capital structure.

In support of this contention, Verizon argues that economists measure the percentages of debt and equity in the capital structure by first calculating the market values of the firm's debt and the firm's equity, then calculating the ratio of those values. (Ex. 1, p. 18.) According to Verizon, managers analyzing capital structure in this way can best choose a financing strategy to maximize the value of the firm. (Ex. 1, p. 19.) Verizon also asserts this definition is widely accepted in other contexts such as real estate. Further, Verizon's witness argues that rational managers would not commit resources to investments in new markets unless the expected return on the market value is expected to be greater than or equal to the firm's cost of capital, measured on a market value basis. (Ex. 1, p. 20.) Finally, Verizon cites the FCC's *Local Competition Order* for the proposition that UNE costs must be determined by TELRIC analysis that excludes embedded or historical costs. LCO at ¶ 673.

The effect of using a capital structure based upon book value rather than market value, Verizon argues, would increase a company's risk of falling into bankruptcy, and therefore raise its cost of capital. Highly leveraged start-up companies, Verizon points out, have experienced high failure rates in the telecommunications industry.

Verizon states that other parties incorrectly include a short term debt component to determine capital structure. Because it characterizes short term debt as working capital, Verizon avers such debt should not be included in the investment component of UNE costs.

2. MCI

MCI recommends the Commission adopt the capital structure put forth by BayRing/Conversent, one that reflects the book value capital structure of the consolidated Verizon company, Verizon Communications Inc. According to MCI, the consolidated capital structure is a suitable proxy for what Verizon would use if it were to seek financing for all of its investments and operations now.

MCI opposes Verizon's proposed market value capital structure as neither representative of how management actually raises capital and manages capital structure, nor how investors make investment decisions. MCI argues that book value is what Verizon reports to the Securities and Exchange Commission, not market value structure. Further, MCI claims that, as of September 30, 2002, Verizon Communication's market value capital structure was 58% equity and 42% debt, markedly different than the 75%-25% structure Verizon wishes to adopt here.

MCI objects to Verizon's characterization of a book valued capital structure as not forward looking and contrary to TELRIC principles. MCI avers that such a characterization is misleading, because the book value itself is to be used to predict the future capital structure that Verizon would use to finance future investment and operations. MCI argues the capital structure proposed by BayRing/Conversent is forward-looking.

MCI also opposes Staff's proposal to use Verizon New England's book value capital structure. MCI points out that

Verizon New England, as a wholly owned subsidiary of another wholly owned subsidiary of Verizon Communications Inc., can report a book value that does not reflect the actual sources of financing. Therefore, MCI recommends using the capital structure of the ultimate corporate level where financing decisions are accurately reflected.

MCI agrees with BayRing/Conversent that short term debt should be accounted for in the cost of capital calculation. In support, MCI argues that Verizon itself concedes that short term debt is present in the capital structures of the S&P industrials that Verizon claims are comparable.

3. BayRing/Conversent

BayRing/Conversent recommend using the capital structure actually implemented by the management of Verizon Communications, Inc., the ultimate parent of Verizon NH. Verizon Communications' capital structure is appropriate, according to BayRing/Conversent because: (1) Verizon NH is not publicly traded; (2) the parent has a vested interest in the subsidiary's debt level; (3)the parent can issue debt that will be reflected as equity by the subsidiary's internal books and, similarly, the sum of the subsidiaries' booked equity may exceed the total consolidated equity of the parent; (4) the parent uses buyback transactions to reduce its own level of equity without impacting the books of its subsidiaries; (5) the higher risk level of other Verizon subsidiaries puts upward pressure on the level of common equity in the capital structure; (6) other states have used the capital structure of Verizon Communications to determine UNE rates; and (7) Standard and Poor's uses the parent company's capital structure to determine creditworthiness in order to avoid accounting and bookkeeping manipulations. According to BayRing/Conversent, the capital structure reported by Verizon Communications, Inc. is 37.60% equity, 51.70% long term debt, and 10.70% short term debt.

Use of the parent's capital structure, BayRing/Conversent argue, will produce the lowest overall cost of capital in the long-run for both UNE and retail operations of Verizon. They further argue that use of this structure is TELRIC compliant (Exh. 3, at 12-13) because it recognizes that a carrier attempting to replicate the Verizon network would strive to obtain the most favorable financial picture. BayRing/Conversent posit that since equity costs more than debt, and its return is subject to income taxation, the most favorable financial picture means using the smallest amount of common equity that is reasonable, i.e., the smallest amount that can be carried without jeopardizing the company's ability to attract bond investors or increasing the cost of debt.

BayRing/Conversent contest Verizon's assertions that Verizon NH's operations are financed by retained earnings and the debt of Verizon New England. BayRing/Conversent claim that this is the kind of accounting manipulation that Standard and Poor's avoids by looking to the parent's capital structure. For the same reason, BayRing/Conversent also argue that Staff's use of the capital structure of Verizon New England is not justified.

BayRing/Conversent support the use of a book value capital structure. They contend that book value, being the actual investment made by equity investors in a company, reflects the way management raises capital for current and future investments: by demonstrating it provides safe and adequate service at prices that attract customers.

Market value capital structure, they point out, is not used by rating agencies and is not the forward-looking capital structure responsible management uses to decide how to fund new investments. Book value is the standard practice used by state regulators, whereas, market value is not used, according to BayRing/Conversent. BayRing/Conversent declare that states are wise not to use market value capital structure because its use would be inconsistent with the United States Supreme Court's findings in *Hope*. BayRing/Conversent argue that, contrary to *Hope*, market value capital structure would result in an upward spiral where higher stock prices would produce higher income requirements and *vice versa*. They further contend that TELRIC compels only that telecommunications equipment must reflect market costs for rate setting purposes. They argue that TELRIC does not compel a capital structure that reflects market value.

Reflecting the fact that a company can incur both long term and short term costs of debt, BayRing/Conversent maintain that both should be accounted for in determining a weighted average cost of capital.

4. OCA

The OCA recommends the Commission adopt a capital structure for Verizon in which the debt to equity ratio is 55:45. This represents an average of the reported capital structure of Verizon New England at year end 2000, year end 2001 and as of June 30, and September 30, 2002. The OCA claims that this average is close to Verizon New Hampshire's capitalization. This use of a longer-term historical average rather than a more recent value, in the opinion of the OCA witness, is more appropriate.

5. Staff

Because Verizon is not required to report the capital structure for the State of New Hampshire affiliate, Staff recommends the Commission use the capital structure reported by Verizon New England. Staff's testimony recommends using the reported book value of equity and debt as of June 30, 2002: 44.784% equity and 55.216% debt. Staff posits that this capital structure is a conservative estimate of the current book value given that Verizon has since continued to carry short term debt and increased its long term debt amount to above 59%.

Staff argues that book value of debt and equity is appropriate for determining the capital structure rather than the use of market value as Verizon proposes. According to Staff, importing TELRIC methodology for setting UNE rates, which Verizon raises as the justification for applying market value, to determine all regulated rates of a company, would not be rational. Staff points out that TELRIC methodology does not apply to the S&P companies that Verizon chooses for its sample companies in determining a cost of capital and, furthermore, only a small fraction of Verizon's business deals with UNEs.

Staff argues that because CLECs are currently making new investments in network elements in order to commence business, CLECs have incentive to build their networks as the TELRIC methodology suggests, by choosing the most efficient technology and by taking wire centers as given. Staff asserts that CLECs minimize their weighted average cost of capital by utilizing more low cost debt than equity in their capital structures. CLECs' current costs of capital are very different from that proposed by Verizon and, Staff argues, that a forward looking capital structure would look more like that of the CLECs, (e.g., companies who have operational characteristics similar to the assumptions required by TELRIC) than Verizon's market based capital structure.

Staff also argues that the market value capital structure that Verizon proposed is not a calculation that management uses when deciding whether to seek capital to finance assets. Investors do not rely on market-value information either, Staff states, since that information is rarely published.

B. Cost of Debt

1. Verizon

Again declaring that the TELRIC standard requires UNE rates to reflect the cost of reconstructing its network using the most efficient technology at the time rates are set, Verizon recommends a cost of debt of 7.40%. The recommendation is the average yield to maturity on Moody's A-rated industrial bonds for April 2002, as reported in the Mergent Bond Record. According to Verizon, 7.40% is a conservative estimate as it does not include flotation costs, *i.e.* financing costs, that the company would incur if it were to issue new debt to reconstruct its network.

2. MCI

MCI maintains that Verizon's arguments in support of using market rates should apply to the cost of debt. The record evidence, according to MCI, shows that the market interest rate for Verizon's long term debt as of January 17, 2003 was 6.315%. MCI avers that this figure is lower than the figure put forth by Verizon and lower than the figure put forth by the OCA because it is more current than the April 2002 and October 2002 rates that Verizon and the OCA reported. According to MCI, interest rates have fallen since that time and MCI's rate is the most current rate in this record.

MCI recommends the Commission adopt 6.315% as the rate for long term debt and 2%, which is undisputed in this docket, for short term debt.

3. BayRing/Conversent

BayRing/Conversent recommend the Commission set cost of debt based on what it would cost Verizon to issue debt today. BayRing/Conversent contend that the current cost of long term debt is 6.43% and the current cost of short term debt is 2%. The 2% short term cost of debt that BayRing/Conversent recommend was not contested in this docket.

BayRing/Conversent arrived at the long term cost of debt by adding the 0.45% interest rate spread from the BondsOnline website to the 5.98% cost of Aaa-rated corporate debt as reported on the same website. BayRing/Conversent conducted a reasonableness check on that resulting rate of 6.43% by comparing it to the yield to maturity, 6.325%, on Verizon New York non-callable bonds that mature on April 1, 2032.

4. OCA

The OCA recommends applying different costs of debt to the retail portion and the UNE or wholesale portion of Verizon's business. For the retail portion, the OCA recommends using an embedded cost of debt of 7.051% and for the wholesale portion, the OCA recommends using the marginal cost of debt of 6.79%, which is the average of A-rated utility bond yields for the period of September 20, 2002 through October 25, 2002.

5. Staff

Staff utilizes the cost of debt that Verizon New England carries on its books, 7.051%, which is the cost of debt reported on June 30, 2002. Staff argues this value is directly observable and can therefore be used without further estimation. Staff also points out that using the embedded cost of debt is consistent with the regulatory practice of calculating a cost of capital based on the regulated company's cost of debt rather than that of a proxy group, as Verizon recommends.

C. Cost of Equity

1. Verizon

Verizon proposes a Cost of Equity of 14.13%. For its application of the DCF model, Verizon chooses 108 Standard and Poor (S&P) industrial companies as a proxy group. Verizon argues that this proxy group is appropriate because a forward-looking cost determination must assume a competitive market.

Verizon submits that the S&P Industrials are a comparable proxy group because there are no publicly traded companies that have built a network solely to provide wholesale services, and because the S&P Industrials face risks similar to those faced by Incumbent Local Exchange Carriers (ILECs). Verizon avers that the S&P sample is a conservative proxy because those companies actually face less risk than Verizon. In support of this claim, Verizon argues that local competition in New Hampshire is widespread and there is a daily increasing risk from local wireline and wireless competitors. Verizon also argues that the proxy companies relied on by Staff and the intervenors in this docket are inappropriate. According to Verizon, Staff's sample of telecommunications holding companies is "too small to provide a broad set of telecommunications services over a wide geographic area" (Verizon Brief p. 22) and the Intervenors' sample of regulated utilities do not face the same risks encountered by Verizon in New Hampshire.

Verizon employs a one-stage DCF calculation to determine the cost of equity. Verizon attacks Staff's use of the three-stage version, claiming that it failed tests conducted by Verizon's witness to check its reasonableness. Verizon's witness applied the three-stage version to the S&P Industrials and the S&P 500 and compared the resulting costs of equity. Verizon's witness claims that he obtained lower costs of equity for companies that should be considered higher risk investments, contrary to reason and expectation. The Verizon witness also compared his three-stage DCF results with reported ValueLine betas, a publicly available measure of risk. The Verizon witness's application of the model also produced costs of equity less than the yield on A-rated utility bonds and, in a comparison of the average growth rates in the three-stage version to price/earnings ratios, Verizon's witness obtained growth rates he stated were unrelated to stock prices as reflected in the price/earnings ratio.

For the dividend component, Verizon's DCF recognizes that "dividends are paid quarterly and that Verizon would have to pay flotation costs to finance a reconstruction of its network as assumed by TELRIC standards." Verizon Brief, p. 26. Verizon argues that the Intervenors fail to account for these two considerations.

For growth rate, Verizon uses the I/B/E/S/ consensus analysts' growth estimates for the S&P Industrials. Verizon's rationale is that investors rely on analysts' forecasts and investors are the relevant standard.

2. MCI

According to MCI, the accuracy of the DCF model depends on accurate identification of the growth rate assumed by investors. MCI argues that the earnings growth rate must be sustainable. In MCI's view, Verizon's assumption of 12.22% annual growth, forever, is unsustainable and unreasonable. MCI points out that the record shows that the highest long-run growth forecast for real gross national product is approximately 2.5% annually. Furthermore, MCI claims that Verizon provides no defense of its prediction other than to state it is based upon analysts' growth forecasts published by I/B/E/S/. Since investors are well aware that analysts' earnings projections may be biased upwards, MCI declares, Verizon is unreasonable to assume that those investors will give the projections full credence. MCI therefore pronounces that Verizon fails to meet its burden of proving the reasonableness of its estimate of the cost of equity.

MCI believes that both Staff and BayRing/Conversent witnesses demonstrated the reasonableness of their estimated cost of equity. MCI recommends that the Commission adopt a cost of equity between 9.581% and 9.75%, the respective estimates of those witnesses. MCI supports Staff's three-stage DCF version, concluding that it estimates a sustainable long-run growth rate by combining and weighting different growth rates, based upon forecasted and historical earnings and dividends for three periods.

MCI also approves BayRing/Conversent's DCF methodology because it conforms to MCI's premise that analysts' forecasts are not an accurate statement of the sustainable long-run growth expected by investors.

3. BayRing/Conversent

To calculate Verizon's cost of equity, BayRing/Conversent used both a single-stage and a multi-stage version of the DCF methodology and both an inflation-based approach and an historical approach to the risk premium/CAPM methodology. The cost of equity BayRing/Conversent recommend as a result of these calculations is 9.75%.

For the DCF methodology, BayRing/Conversent chose comparison groups of companies: a group of three large publicly traded telephone holding companies, a group of electric companies, gas companies, and water companies. The inclusion of higher risk telecommunications companies that contain unregulated service providers balances the inclusion of the lower risk regulated utility companies, BayRing/Conversent profess, and produce an outcome neither too high nor too low. BayRing/Conversent point out that their cost of equity was, until making a capital structure adjustment, virtually the same as found by Staff.

In applying the constant growth form of the DCF formula, BayRing/Conversent argue that growth should be quantified in a manner that ensures that the retention rate used to compute the dividend yield is the same as the retention rate used to compute growth. Therefore, they argue, the total amount of future expected earnings allocated in aggregate to dividends and growth will be something other than 100% earnings, thus validating the results. (BayRing/Conversent Brief, p. 31.) The multi-stage form of the DCF formula used by BayRing/Conversent uses ValueLine projections for the early years. For the later years, going out to 40 years, BayRing/Conversent use a formula multiplying the future book value per share by the future expected earned return on book equity.

BayRing/Conversent conducted a risk premium/CAPM examination of the relationship between earned returns on common stocks and earned returns on bonds since 1926 by looking at a comparison of the "30 Year Moving Average of Return on Large Common Stocks" versus Corporate and Treasury bonds. The risk premium/CAPM model demonstrates a clear downtrend in risk premiums, according to BayRing/Conversent.

In rebuttal to Verizon's claims, BayRing/Conversent assert that Verizon's witness's implementation of the DCF method contains at least five significant flaws. First, relying only on earnings per share growth forecasted for the five years from 2001-2006 as a proxy for long term growth makes the mathematically impermissible assumption that such growth forecasts will continue forever. According to BayRing/Conversent, this is incorrect in a DCF formula that requires a long term sustainable growth rate. More sophisticated models, BayRing/Conversent claim, compare the sustainable growth rate using the future expected value of "r" in a "b x r" computation (retention rate multiplied by future expected return on book equity). Furthermore, BayRing/Conversent argue that such forecasts have been shown to have an habitually upward bias and therefore using analysts' five year earnings for shared growth rates in the DCF formula will overstate the growth rate and the cost of equity.

Second, BayRing/Conversent claim that Verizon uses a group of the S&P Industrials that is not comparable. They cite the Supreme Court's decision in *Verizon v. FCC*, 122 S.Ct. 1646, 1662 (May 13, 2002) for their belief that ILECs have a tremendous competitive advantage that would preclude competition in an unregulated world. BayRing/Conversent conclude that the regulated retail portion of Verizon Communications faces relatively low risk. For that reason, BayRing/Conversent argue Verizon's sample group is not reasonable. BayRing/Conversent also argue that Verizon's UNE business is low risk. In support, BayRing/Conversent point out that Verizon has no obligation to provide the facilities if the elements are not already available, thus removing any investment capital risk.

Third, BayRing/Conversent claim that Verizon incorrectly adjusts dividend yield upward by compounding quarterly. While it is true that companies typically pay dividends quarterly, BayRing/Conversent deny that the effect is to increase growth. They assert that growth is suppressed when a company disperses cash to shareholders. If the effect of dividends is to be compounded quarterly, BayRing/Conversent argue, the return on equity that a company receives should be compounded daily. They contend that this would result in obtaining a higher return on equity than that authorized and therefore a lower authorized return would be appropriate.

Fourth, BayRing/Conversent claim that Verizon improperly eliminates companies from the DCF analysis if the indicated cost of equity was outside a particular range. BayRing/Conversent argue that this action predetermines the DCF result as mid-way between the A-rated bond rate and 20%, an upward skewing that automatically invalidates Verizon's results.

Fifth, BayRing/Conversent claim that Verizon improperly includes a 9 basis point financing cost (flotation) allowance. BayRing/Conversent argue that Verizon has not issued new common equity for years, and that such small costs are eliminated in rounding error, and that Verizon has a market-to-book ratio in excess of 2. This last factor means that external financing is profitable rather than an expense, BayRing/Conversent contend.

4. **OCA**

The OCA contends that Verizon's proposed cost of equity should be rejected by the Commission. The OCA argues that Verizon made an incorrect choice of S&P industrials as its sample group because those companies face higher risks than the local exchange operations of telephone companies. In addition, the OCA argues that Verizon has not adequately supported its decision to exclude dividends from the growth component of the DCF model. According to the OCA, there is no significance to the fact that projected earnings growth alone determines price/earnings ratios more accurately than historical growth averages do alone, at least for cost of capital determination. The OCA points out that no participant in the docket relies solely on historical growth averages. Therefore, the OCA contends, Verizon's calculation produces an incorrect result.

For its own determination of a cost of equity for Verizon utilizing the DCF model, the OCA chose to analyze three sample groups. The first group is the telecommunications holding companies like Verizon Communications. The OCA considers them more risky than local exchange operations and performs the analysis to establish an upper boundary for a range of reasonable rates. Because that group is small, the OCA also performs an analysis of regulated insurance companies. Lastly, to establish a lower boundary of reasonableness, the OCA analyzed the cost of equity for lower risk gas distribution utilities.

The OCA contends that establishing a range of reasonable cost of equity percentages meets the latest and most comprehensive review of the law applicable to ratemaking in New Hampshire, *Appeal of Conservation Law Foundation*, 127 N.H. 606 (1986). In that case, the Supreme Court recognized that a rate of return must fall "within the zone of reasonableness, neither so low as to result in a confiscation of company property, nor so high as to result in extortionate charges to customers." *Id.* at 635. *Appeal of Conservation Law Foundation* also reiterates the "comparable earnings" test set out in *Bluefield*, which the OCA notes must exclude returns that are comparable to those of especially profitable or speculative business enterprises. The OCA posits that, given the telecommunications market, CLECs may fall into the category of highly speculative business enterprises but that Verizon does not.

The OCA established a range of equity cost estimates between 10.50% and 11.75%. The 10.50% figure is the upper boundary of the range for gas distribution companies; the 11.75% is the lower boundary of the range for telecommunications holding companies. The OCA then testified that, in its judgment, 10.875% would be the correct allowable cost of equity for Verizon. However, in its post hearing brief, the OCA recommended a lower rate. The OCA applied the principles set forth in *Appeal of Conservation Law Foundation* to make a recommendation that the Commission set the cost of equity for retail rates by averaging the results of the four methodologies employed by the OCA witness to obtain a cost of equity for gas distribution companies. According to the OCA, the outcome using the average of a CAPM, a Modified Earnings/PE analysis, a market to book ratio analysis and a DCF produces an appropriate cost of equity for Verizon of 9.48%.

The OCA reasons that the cost of equity should be set at this lower rate because of the following: (1) gas distribution companies represent the proper comparable sample, (2) ratemaking case law does not hold that increased risk is followed by an automatic increase in rate of return to investors, *see, Appeal of Public Serv. Co. of N.H.* 130 N.H. 748 (1988); (3) Verizon management's behavior, as indicated in Exhibit 48 resulted in the acquisition of additional debt and equity, when all could have been avoided by distributing fewer dividends to shareholders, while at the same time capital expenditures were reduced; and (4) Verizon's lack of any need to attract capital. In a rate case, the OCA argues, the Commission may look at the actual circumstances of the utility when establishing the rate of return within the range of reasonableness.

The OCA also raises an argument against raising Verizon's cost of equity based upon *Market Street R. Co. v. Comm'n*, 324 U.S. 548 (1945). The New Hampshire Supreme Court referred to *Market Street* approvingly in *Petition of PSNH*, 130 N.H. 265, 277, 539 A.2d 263, 275 (1988), when holding that the *Hope* line of cases does not guarantee net revenues that will preserve a company's financial integrity. In *Market Street R. Co.*, the U.S. Supreme Court dealt with a regulated streetcar company threatened by competition from an unregulated company. The Court found it had no obligation to revive the value of a company whose "'zenith of opportunity' has been eclipsed by the operation of economic forces." *Market Street*, 324 U.S. at 554. The OCA implies that the same situation pertains in this docket.

5. Staff

Staff recommends the Commission adopt a cost of equity of 9.581% for purposes of this docket. In applying a three-stage version of the DCF model to Verizon, Staff chose a sample of three telecommunications firms from the Valueline financial database with comparable risk profiles, positive dividend and earnings growth on average over the last five years, and other similarities to Verizon. The sample is small but, Staff avers, sufficient to create reliability based on the systematic selection process. Because the sample possesses levels of risk and operating and investment profiles that are similar to

Verizon, according to Staff they can confidently be said to be subject to similar risk exposures in the future.

The same cannot be said of the sample of firms Verizon chose for its calculation, the S&P Industrials, Staff claims. Staff argues that Verizon's sample is based only on the wholesale portion of its business, a very small portion that is not representative of Verizon as a whole.

Staff rebuts Verizon's contention that the beta value of S&P Industrials are comparable to the beta value of Verizon, beta being a risk measurement often relied upon by state commissions. According to Staff, Verizon based its claim on data that was incorrectly derived from an abbreviated summary of ValueLine betas, as reported in Exhibit 58. The data that should be consulted, Staff argues, is the underlying ValueLine data which shows that Verizon and other RBOCs have a significantly lower beta and therefore a lower risk than the S&P Industrials.

Staff chose to apply a three-stage version of the DCF model rather than the one-stage version relied upon by the Commission Staff in the past. The one-stage version is premised upon a single growth rate that is assumed to continue *ad infinitum*. Staff argues that a cost of equity calculated by the one-stage version will produce growth rates of dividends and earnings that consistently either under- or over-perform compared to the growth capacity of the economy as a whole. To protect against that unreasonable overly positive or overly negative forecast, the three-stage version produces a growth rate that converges to the long run growth rate of the economy for time periods beyond the ValueLine forecast. Staff cites Ibbotson's 2002 Valuation Edition Yearbook for the proposition that the expected long run growth rate of the economy is an indefinitely sustainable growth rate. Accordingly, Staff argues that the three-stage version is a better model for the Commission to rely on for calculating cost of capital.

Staff's application of the DCF model includes dividends as well as earnings forecasts in the growth component, as directed in the Commission's prior decisions. Staff recommends an equal weighting (50-50) of dividend growth and earnings growth. Staff points out that, according to the Commission's decision in *EnergyNorth Natural Gas, Inc.*, 78 NH PUC 117 (1993), a growth rate that does not include dividends and relies only on earnings forecasts will not provide an accurate return on equity. The EnergyNorth decision, Staff contends, is supported by well-respected economic literature. For example, Staff points to Morin, Utilities' Cost of Capital (1984), at pp. 123-133. According to Morin, Staff says, using earnings growth alone is inadequate because earnings per share are apt to be more volatile than dividends per share.

In addition to rejecting Verizon's proposed growth rate because it is based solely on analysts' earnings forecasts, Staff opposes Verizon's 12.2% growth rate as being unsustainable over time. Since the annual nominal long run sustainable growth rate of the economy has been identified by Staff as 5.5%, Staff contends Verizon's proposed growth rate is too high for use in the DCF calculation.

D. Risk Premium

1. Verizon

Verizon estimates an overall weighted average cost of capital of 12.45% for use in calculating retail rates. In addition, on the basis of an article by Copeland and Weston[2] for describing a methodology for valuing cancelable operating leases, Verizon recommends the Commission supplement that overall weighted average, to calculate UNE rates, with a risk premium of 5.48%[3].

The risk premium is necessary, according to Verizon, because of the additional risk of setting UNE rates assuming

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[2] Copeland and Weston, *A Note on the Evaluation of Cancelable Operating Leases, Financial Management* (Summer 1982) (Exh. 1, Attachment A).

[3] The amount of the risk premium was calculated by (i) recognizing the difference between a fixed-rate, non-cancelable financial lease and a cancelable operating lease; (ii) using available data on the forward-looking investment, operating expenses and depreciation for the Commission-approved Verizon telecommunications network in New Hampshire; (iii) using a standard methodology for valuing the CLECs' option to renew their UNE lease at lower rates when rates are reset to reflect the supposedly lower cost of new technology or to cancel their leases altogether; and (iv) comparing the required rate of return on a fixed-rate, non-cancelable financial lease for Verizon NH's network to the required rate of return on a cancelable operating lease for this network.

construction of a telecommunications network using the most efficient current technology while at the same time offering CLECs the option of canceling UNE leasing contracts. Verizon posits that recent telecommunications industry history proves that companies and investors recognize the enormous risk of such investments, a risk that is not reflected in stock prices. The companies whose stocks are publicly traded, unlike Verizon New Hampshire[4], dedicate only a small portion of their business to cancelable leases; therefore, their stock prices do not reflect the amount of risk involved in a UNE company, that is, one devoted entirely to providing cancelable leases. Further, according to Verizon, the proxy companies are not regulated and therefore are not subject to the TELRIC standard. Verizon argues that failure to include regulatory risk will send incorrect economic signals to both competitors and to incumbent carriers.

2. MCI

MCI disputes Verizon's assertion of additional risk attributable to TELRIC regulation, as explained at the beginning of this section. MCI also disputes Verizon's assertion of actual risk in the New Hampshire market. According to MCI, the Commission has concluded in past litigation that such risk is

[4] Verizon New Hampshire is a subsidiary of Verizon New England which, in turn, is a subsidiary of Verizon Communications.

analyzed and accounted for by investors and is therefore manifest in the market price of common stock. MCI contests Verizon's statement of a financial truism that "the higher the risk, the higher the cost of capital." The correct formulation, MCI maintains, is "the higher the non-diversifiable risk, the higher the cost of capital." In this case, investors can themselves diversify risk and Verizon need not do so.

MCI also challenges Verizon's assertion that it faces a strong threat to its profitability which must be addressed by increasing the cost of capital. According to MCI, the record shows that demand for both retail and wholesale access lines continues to grow, including interstate special access lines. Interstate access lines should be included in the Commission's analysis, MCI avers, because the point is that the lines are in use - not that they are jurisdictionally interstate - and, furthermore, a substantial portion of the traffic on such lines is actually intrastate anyway.

MCI dismisses the risk premium Verizon attaches to the weighted average cost of capital for UNEs as imaginary and irrelevant. The assumptions necessary to analogize a lease contract that is cancelled, leaving the entire network stranded, cannot be taken seriously by practical regulators, according to MCI. MCI reasons that retail customers, like CLECs, can cancel their Verizon service but such cancellation does not result in stranded investment: UNE facilities will be used by future wholesale customers or by Verizon itself and therefore will not be stranded. MCI argues that TELRIC principles recognize that local network investment will be recovered by incumbents through retail and wholesale usage combined. In sum, MCI claims that no lease termination premium is necessary or reasonable, and that it would only inflate UNE rates.

3. BayRing/Conversent

BayRing/Conversent object to the addition of any risk premium attributable to the cancelability of UNE lease arrangements. They argue that the monthly lease for UNEs was a Verizon business decision. Further, they argue, Verizon is exposed to little actual risk since its facilities will be used whether a customer uses a CLEC's leased facility or Verizon's underlying facility. In addition, they assert that Verizon provided no proof that CLECs are abandoning UNE entry, that Verizon makes no incremental investment in UNE facilities in the first place, and that loop facilities in New Hampshire have been priced based on a utilization factor of 37.2%, thus adequately compensating Verizon for over-capacity.

Finally, BayRing/Conversent reject Verizon's claim that TELRIC precludes Verizon from recovering its investments in its network.

BayRing/Conversent argue that Verizon's cite to a recent U.S. District Court ruling on a New Jersey Board of Public Utilities decision is unavailing. The New Jersey District court did not lower UNE rates by 40%, they assert, it merely remanded the case to the BPU for further calculation. BayRing/Conversent maintain that Verizon should seek changes to its rate of depreciation in the next TELRIC proceeding, rather than attacking the problem indirectly via cost of capital.

4. OCA

The OCA argues against awarding any risk premium for Verizon's UNE services, since the regulatory context in which Verizon operates already accounts for the risks it encounters. Assets that support UNE services are either leased to a CLEC or returned to regulated rate base, providing regulatory protection according to the OCA. Only an extreme excess capacity situation could trigger the risk Verizon claims and the OCA argues that extreme excess capacity is highly unlikely as Verizon does not make capital investments for CLECs. The OCA dismisses Verizon's lease option theory as a reason to impose a risk premium; the theory is unorthodox and produces absurd results when applied to Verizon's actual capital structure. Finally, the OCA argues that the record contains no quantification of Verizon's alleged TELRIC shortfall and therefore it should not be seriously considered.

5. Staff

Staff disagrees with Verizon's definition of risk. According to Staff, risk encompasses both good and bad outcomes and the variability of both good and bad outcomes must therefore be factored into risk measurement. Verizon's definition of risk, Staff contends, results in an artificially high cost of capital, focusing on a small part of the corporation and requiring, further, a finding that the FCC's TELRIC standard is a guarantee that the RBOC can never ever earn its assigned cost of capital. Even if the Commission were to accept Verizon's definition of risk, Staff argues, it should not apply that definition to 100% of the company.

Staff also contends that the 5.48% risk premium that Verizon proposes the Commission apply to the overall weighted cost of capital should be rejected. One cannot compare UNE provisioning to an operating lease of a newly built network for the lessor's purposes, and, as Staff further argues, it is inappropriate to apply an increment to the average cost of capital that already compensates investors for assuming the risks the company faces as a whole.

IV. COMMISSION ANALYSIS

The purpose of this docket is to determine the cost of capital required by Verizon NH for its regulated telecommunications business. The parties differ over whether distinct rates of return must be set for Verizon's UNE (wholesale) business as opposed to its retail business and, if so, how to estimate such differentiated rates. They also differ on what capital structure should be employed, how to determine the cost of equity, and the proper estimation of the cost of debt.

The parties do agree on the overall legal framework that should guide our decision. It is well expressed in the OCA's brief, which we liberally paraphrase here. The most comprehensive review of the New Hampshire law on cost of capital may be found in *Appeal of Conservation Law Foundation*, 127 N.H. 606, 633 *et seq.* (1986). There, the Court articulated the standard of reasonable rates and the Commission's duties in light of the standard:

> The Commission is bound to set a rate of return that falls within the zone of reasonableness, neither so low as to result in a confiscation of company property, nor so high as to result in extortionate charges to customers. *Id.* at 635, citing *Legislative Utilities Consumers' Council v. Public Serv. Co. of NH,* 119 N.H. 332, 341-42 (1979).

The Court further noted that the lower boundary of the zone of reasonableness should be a rate that, at a minimum, is sufficient to "yield the cost of the debt and equity capital necessary to provide the assets required for the company's responsibility." *Id.* Subject to exceptions permitting the Commission to assume a hypothetical capital structure and to make allowances for the relative efficiency of management, *see id.* at 635-636, the upper boundary is a rate "sufficient to yield a return 'comparable to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties.'" *Id.* at 635 (citing *Bluefield,* 262 U.S. at 692, *New England Tel. & Tel. Co. v. State,* 113 N.H. 92, 95 (1973) and other authorities). The Court has found that this zone of reasonableness does not include "returns commensurate with 'highly profitable enterprises or speculative ventures.'" *Appeal of Public Service Co.*, 130 N.H. 748, 756 (1988).

A. Retail vs. UNE Cost of Capital

We address at the outset whether to set different costs of capital for Verizon's retail and wholesale (UNE) lines of business in New Hampshire. Verizon points to our order of notice, in which we stated that one of the purposes of this docket was to determine if TELRIC rates should be modified to take into account a revised cost of capital. Verizon asks that we establish a separate cost of capital for the retail and UNE parts of its operations, based upon different asserted risks associated with each line of business. Verizon claims that its wholesale provisioning business is entirely different from its retail business, facing risks so disproportionately large as to justify a 5.48 percent risk premium applicable to the overall cost of capital for that separate and distinct portion of its jurisdictional enterprise.

Essentially, Verizon is asking for a cost of capital differentiated by rate class, in this case, retail versus wholesale. Such a segregated approach is not supported by the specific facts of this case. For example, Verizon argues that CLECs can discontinue use of UNEs, and that Verizon is thus at risk of losing revenues associated with UNE facilities. The CLECs reply that it is unlikely that a CLEC, having chosen to pursue UNE provisioning, will withdraw from such a business. We need not decide which view is the correct one. Whatever the case may be with respect to CLEC business models, the risk of demand reductions is not unique to Verizon's UNE line of business given that retail customers who have not signed special contracts are free to take their business to competitive carriers.

It is also unclear on this record to what extent Verizon faces the risk of stranded investment as the result of the departure of any group of customers. Both UNE and retail facilities typically can be re-used by Verizon to serve other customers in the same line of business or to serve customers in the other line of business. This substantially reduces the extent of risk faced by Verizon. Investments made to serve retail customers can ordinarily be recovered under rate of return regulation, so long as the expenditures are prudent. In the case of UNEs, Verizon's lack of legal obligation to build out its network with new facilities merely to serve CLEC demand minimizes the risk it faces with respect to loss of wholesale customers. Thus, practically speaking, all Verizon investment for which it claims it is at risk is actually subject to the protections afforded by regulation.

There are also difficulties in determining the separate cost of capital for any given line of business. We note that RSA 378:17-b, IV precludes the Commission from mandating separation or divestiture of Verizon into separate wholesale and retail firms absent legislative approval. We find it inappropriate to embark on an exercise that would effectively require us to examine the wholesale and retail functions separately for cost of capital purposes. Further, even if we elected to engage in such a separation exercise for rate design purposes, on the record before us we cannot quantify the risk differentials or allocate those asserted risks to particular revenue or asset amounts as Verizon does not report those revenues or assets in accounts separated into wholesale and retail activities. In addition, we note that neither the TELRIC method nor the TRO requires the specification of a separate cost of capital. There is no requirement under FCC rules or the TAct that a separate cost of capital be specified for UNE rates.

We conclude that it is reasonable to view the company as a whole to arrive at a weighted average cost of capital. This overall cost of capital will be utilized by Verizon for jurisdictional filings that require cost studies that call for an estimate of the cost of capital. More specifically, we will use this overall weighted average cost of capital to modify TELRIC rates; we will also use this overall weighted cost of capital in any future retail rate case and in examining Verizon's earnings going forward.

B. UNE Risk Premium

There are several infirmities with regard to the 5.48 percent risk premium Verizon proposes to add to its overall cost of capital which prevent us from adopting it. In particular, the method advanced by Verizon's witness Dr. Vander Weide to derive the risk premium is inapplicable to the UNE situation.

In the article cited by Dr. Vander Weide to support his UNE risk premium (Copeland and Weston), the authors developed a method to estimate the appropriate cost (and associated internal rate of return) for a cancelable equipment lease, as opposed to a non-cancelable equipment lease. According to Copeland and Weston, if a lessee can cancel an equipment lease, the lessor must adjust the lease fee upwards from a non-cancelable lease fee to reflect any uncertainty as to the likely economic value of the property at the times when the lessee may exercise this option. The risk is on the lessor, and the required lease payments and internal rate of return must reflect this assumed risk. The authors point out that from the lessor's point of view, a cancelable lease is equivalent in value to a pure financial lease (which cannot be cancelled and which, according to the authors, has a cost equal to the cost of debt), minus an American put option with a declining exercise price. *Id.*, at 60.

Dr. Vander Weide calculated his 5.48% risk premium drawing on the arguments developed in the paper, and added it to his estimate of 12.45% weighted average retail cost of capital, to arrive at his recommended 17.93% weighted average UNE cost of capital. Whatever the merits of the cancelable lease analogy to the UNE line of business, we find that it is not appropriate to use the Copeland/Weston formulas to develop a UNE risk premium, and add the resulting premium to an overall cost of capital to develop a separate rate of return for UNE leasing.

Second, use of the Copeland/Weston theory in the UNE context implicitly assumes that it is only the action of the lessee in demanding cancelability that subjects Verizon to the risk of cancellation. As the CLEC parties pointed out, it is Verizon that restricts CLEC UNE leases to one-month terms, and declines to offer longer term non-cancelable UNE leases. Presumably this is a result of a judgment by Verizon that its risk is decreased, not increased, by shorter terms, notwithstanding the associated exposure to increased risk of CLEC discontinuance of service.

The analogy between Copeland/Weston and the UNE line of business breaks down further as the value of the premium depends fundamentally on the investment required to serve the lease (Version Att. A, p. 65). Copeland/Weston state that a higher investment expense produces a higher premium (*id.*, pp. 64-5). However, as we have noted above, Verizon is not required to incur investment expenses explicitly for CLEC lines of business.

In addition, as stated in footnote 6 of Copeland/Weston, the lessor must, when faced with a cancellation of a lease, either "a) sell the asset at market value, or b) lease it again at a lower rate." We find neither of these scenarios persuasive for the actual business of a regulated provider of UNEs. We note that the possibility of the leased asset returning to the retail side of Verizon's business and earning a higher return than the original UNE lease is inappropriately excluded from the application of Copeland/Weston to UNEs.

Finally, no reasonable basis has been advanced in this case to apply a cancelable lease analogy to the UNE business, as opposed to the retail business. With the exception of individual long term contracts or special tariffs, none of Verizon's customers, wholesale or retail, are bound to remain with Verizon. Arguably, any premium that may apply to reflect the cancelable nature of the use of Verizon's facilities applies to retail service as well as wholesale service. However, as we note above, we have no basis on this record to differentiate the risk of retail and UNE business. In any event, the risk of revenue loss from demand reductions is captured in the overall rate of return, properly set, as is all risk facing the firm.

The Copeland/Weston argument, while perhaps sound for the purpose for which it was conceived, is not appropriate for application to the UNE business. For these reasons, it would be inappropriate to add the proposed premium to the UNE prices, and we decline to do so.

C. Capital Structure

In *Appeal of Conservation Law Foundation of New England*, 127 N.H. 606 at 636, 507 A.2d 652 (1986), the New Hampshire Supreme Court opined that in setting a reasonable rate of return for a regulated company, the Commission must look both at capital costs and comparable risks outside the company and also at the "actual circumstances" of the company. *Id.* at 635.

The efficiency or inefficiency of management, for instance, may be recognized. *Id.* The Supreme Court stressed the role that judgment plays in setting a rate of return. *Id.* at 636. The Court also stated that in striking a fair balance between the interests of the ratepayer and the shareholder as required by *Hope*, the Commission may impute a capital structure that it finds to be appropriate, rather than using the actual capital structure. *Id.* We note that in subsequent cases we have relied upon the Court's opinion, recognizing that "commissions are entitled to 'make the pragmatic adjustments which may be called for by particular circumstances,'" *Kearsarge Telephone Company*, 73 NH PUC 320, 326 (1988), citing *Federal Power Commission v. Natural Gas Pipeline Co.*, 315 U.S 575 at 586, 42 PUR NS 129, 86 L.Ed. 1037, 62 S.Ct. 736 (1942), and must "exercise … a 'fair and enlightened judgment, having regard to all relevant facts.'" *Id.*, citing *NET vs. State*, 104 NH 209 at 234, 44 PUR3d 498, 183 A.2d 237 (1962) quoting , 262 U.S. at 692,).

In our judgment, capital structure would preferably be based upon book value, not market value. We do not accept the premise that TELRIC principles mandate construction of a market value capital structure for the company. TELRIC requires a forward-looking estimate of capital costs, but it does not require a capital structure based on the market value of the components of the company's capital exposure. A company's book value capital structure is within the company's control. Verizon has strong incentives to minimize its financing costs and, therefore, book value capital structure could be considered TELRIC compliant. Book value properly reflects the basis on which a company's management raises capital for investments, and the manner in which investors and investment rating agencies evaluate a company.

Having decided that book value is the preferred tool for determining the company's capital structure, we must exercise judgment in determining the appropriate book value capital structure. We must use a hypothetical capital structure in the case of Verizon NH, because Verizon NH does not exist as a legal entity, has no capital stock, and issues no debt. Accordingly we have looked at the various proxies proposed by the parties. As noted above, Verizon did not propose a capital structure based on book values. BayRing/Conversent and MCI recommend adoption of the capital structure of Verizon Communications, Verizon NH's ultimate parent company: 37.60% equity/51.70% long term debt/10.70% short term debt. Staff recommends adoption of the capital structure of Verizon NH's nearest reporting entity, Verizon New England: 44.78% equity/55.22% debt as of June 2002. Mr. Schlegel observed in his testimony at the hearing that it would be appropriate to include short term debt, but that when he prepared his testimony he did not have access to sufficient data to identify the short term debt portion of the Verizon New England capital structure. Tr. Day II, p. 44.

The OCA recommends using a longer term historical book value of Verizon New England for the capital structure of the retail portion of Verizon's business (45% equity/55% debt), and using a market value of the OCA's sample firms for the capital structure of the wholesale business if the Commission segregates cost of capital for the retail and wholesale lines of business.

We evaluate these recommendations from the perspective of what a reasonable and prudent manager would choose for a capital structure. It is important for Verizon, which remains the dominant provider of essential telephony services, to maintain a capital structure that adequately insulates consumers from excess debt or excess equity in the capital structure. Unduly high debt leveraging could result in liquidity difficulties that could impede the company's ability to meet its public service obligation. Excess equity creates a capital structure that is too rich, and fails to take advantage of opportunities to raise lower-cost debt funding. While we recognize that Verizon continues to have certain public service obligations, we believe that the record demonstrates that a prudent manager facing the need to raise capital in today's market would place greater emphasis on debt than perhaps would have been warranted when the Commission last set Verizon NH's cost of capital. Today, debt is a significantly lower cost source of capital in comparison to equity, albeit both components of capital are at near-record lows. A prudent manager would seek some additional debt financing. The underlying capital structures recommended by Staff and the OCA, approximately 45% equity and 55% debt, reflect this prudent approach.

We are mindful of the caution expressed by BayRing/Conversent that Verizon Communications, like any ultimate corporate parent in a holding company structure, has the ability to manage its progenies' debt to equity ratios such that the actual capital structure of the subsidiary is an unreliable basis for ratesetting.[5] Indeed, the testimony of BayRing/Conversant's witness Rothschild reveals a basis for questioning whether the capital structure of Verizon Communication's numerous subsidiaries may have been managed by the corporation for corporate ends, thus reducing the value of looking at any subsidiaries' actual capital structure to

[5] Regulatory thought has evolved since the Commission's decision in *Re New England Telephone and Telegraph Company*, 65 NH PUC 564 (1980) (*NET Order)* that rejected an argument that the consolidated capital structure of AT&T consolidated (the ultimate corporate parent) should be used for Verizon New England's predecessor. At the time the *NET Order* was issued, the regulatory concept of "double leveraging," which recognizes that part of the subsidiary's equity may consist of funds borrowed by the parent at low rates of interest, was novel. *Id.* at 585-587.

determine what would be expected from prudent management facing the capital markets directly.

As to BayRing/Conversant's recommendation that the Commission should adopt the capital structure of Verizon Communications, we find that this would not be a good proxy for the hypothetical prudent capital structure of Verizon NH, because the ultimate corporate parent includes a substantial amount of riskier and unregulated ventures such as wireless services, which makes it too dissimilar from Verizon NH to be a reasonable proxy for setting cost of capital for the overall jurisdictional business.

We find Staff's recommendation to look to the actual book value capital structure of Verizon New England reasonable from the perspective of a prudent manager. However, we find that it is reasonable to reflect the components of the entire capital structure of Verizon New England, rather than the equity and long term debt alone. In response to record requests we initiated during our deliberations, Verizon provided, for the period of January 1, 2000 to December 31, 2002, spreadsheets containing the daily balances of short term debt held by Verizon New England. As part of its response, Verizon argues that short term debt should not be included in UNE cost studies because Verizon primarily uses short term debt to finance working capital rather than plant (*i.e.*, UNE) investments, and because the Commission has not included short term debt in capital structure when setting an allowed rate of return.

Regulatory literature indicates two schools of thought regarding the inclusion of short term debt in the capital structure. *Principles of Public Utility Rates*, the 1988 Danielson and Kamerschen adaptation of the seminal work by James C. Bonbright, sets out the so-called short term debt debate, noting at p. 312 that "[S]ome commissions include short term debt in the capital structure, some do not." According to the authors, a factor influencing whether short term debt is included is whether it is a reasonably stable percentage of total capital over time. If it is stable then it could be considered to be permanent and included. Another consideration, raised by Verizon, is whether its short term debt is raised to support cash working capital needs, or plant investment, at least in the UNE context.

In this case the level of short term debt fluctuates considerably day to day but is consistently above zero, and over time averages well above zero; in other words, Verizon New England has consistently carried some short term debt. Review of information provided in response to our record request reveals that the average daily balance for the thirteen months ending December 31, 2002 is 4.35%. Using a thirteen-month daily average smoothes out the variation in daily levels, and reflects a relatively recent and thus representative level of short term debt. We note that the corporate parent, Verizon Communications, has in recent quarters routinely carried considerably higher levels of short term debt, almost double the 10.7% point value identified by Mr. Rothschild in his testimony. See Exh. 37 (JAR Exh. 4).

Verizon's arguments that short term debt should be excluded from the capital structure are unpersuasive. In its Response to the Commission's Record Request 1, Verizon stated that short term debt should not be included in the calculation of the cost of capital for use in UNE cost studies because the company primarily uses short term debt to finance its investment in working capital, and Verizon's investment in working capital is not included in the investment component of UNE cost studies. In support, Verizon claimed that, with regard to retail rate setting, the Commission has not included short term debt in the company's capital structure in setting the allowed rate of return.

We find that sound principles of finance caution against any attempt to "track" dollars raised by a company to any specific purpose. A firm raises capital in a variety of ways, trying always to achieve an overall balance of sources to minimize its costs of money. Short term capital is routinely raised not only when working capital is required, but also when financing is needed for plant investments. Short term debt raised for whatever purpose is routinely rolled over into long term debt when an economic opportunity arises.

We note also that Verizon made its working capital argument not in the context of an overall jurisdictional cost of capital, but with respect to a cost of capital estimated solely for use in UNE cost studies. *See*, Response to Commission Record Request 1. Even if a limitation on the recognition of short term debt were warranted in the case of a UNE-specific cost of capital, an issue we need not address, Verizon does not show that it would be appropriate where, as here, the cost of capital is being estimated for the entire jurisdictional enterprise, not UNEs alone.

The case law of this Commission, contrary to Verizon's statement, contains specific cases, including at least one relating to Verizon's predecessor in interest, in which short term debt is included in the capital structure for purposes of ratemaking. The Commission heard argument in *New England Telephone and Telegraph Company*, 71 NH PUC 285 (1985), in favor of lowering the equity ratio to 50%, and then accepted a settlement agreement that set the capital structure to include 39.03% long term debt and 2.52% short term debt. We therefore conclude that short term debt is not irrelevant to our deliberations and could be included in a reasonable capital structure. *See, In re Pennichuck Water Works, Inc.*, 83 NH PUC 197 (1998); *In re Granite State Elec. Co.*, 81 NH PUC 359 (1996); *Pease v. New England Tel. and Tel. Co.*, 162 P.U.R.4th 110, 1995 WL 389272 , Me.P.U.C. (1995); *Re New England Telephone & Telegraph Co.*, 42 P.U.R.4th 182, Me.P.U.C. (1981); and *In Re Northern Utilities, Inc.*, Docket No. DG 03-080, Order No. 24,175 (May 22, 2003).

According to Verizon data as reported to the Commission, and as detailed in Staff's testimony, Verizon New England's capital structure as of June 31, 2002, consists of $2,527,849,677 total equity and $3,116,671,594 long term debt, with zero dollars of preferred stock outstanding. According to data responses filed by the Company in this docket on June 18, 2003, the average of daily short term debt balances of Verizon New England for the 13 months ending December 31, 2002, is $256,908,734. The capital structure calculated based on the above dollar figures would be 42.84% equity, 52.81% long term debt and 4.35% short term debt.

The day to day volatility of the amount of short term debt, however, makes even a thirteen-month average subject to an objection that it produces a false precision in imputing a capital structure. Nonetheless, it is evident that Verizon has consistently carried a small amount of short term debt for the past few years and that it is prudent to continue to do so. For the purposes of this docket, we conclude that a prudent manager would employ a capital structure for Verizon that includes a debt component of 55%, composed of 53% long term debt and 2% short term debt. Accordingly, applying our expertise to the evidence presented in this proceeding, we will impute a capital structure that is 45% equity, 53% long term debt and 2% short term debt.

D. Cost of Debt

The cost of short term debt was uncontested. We will set the cost at 2% as recommended by BayRing/Conversent and MCI. We will set the cost of long term debt for determining a forward-looking cost of capital based upon the embedded cost of debt for Verizon New England, 7.051% as of the balance sheet for June 30, 2002, as recommended by Staff and by the OCA.

Use of the embedded cost of debt was opposed by Verizon as well as the CLECs. Verizon proposed a cost of debt based upon the average yield to maturity on Moody's A-rated industrial bonds, or 7.4%, pursuant to its thesis that TELRIC requires forward-looking inputs to the cost of capital calculation. MCI argued that the Commission should use the cost of the most recent debt issuance whose cost is on the record, or 6.315% as reported as of January 2003.

Analogous to our discussion of the appropriate capital structure, the embedded cost of debt presumably demonstrates prudent, efficient management and therefore incorporates a forward-looking determination of a company's cost of debt financing. We do not accept the proposition that a proxy is necessary, whether an average of A-rated bonds as proposed by Verizon, or BayRing/Conversent's proposal based upon Aaa-rated bonds plus an additive, when the company's cost of debt is known.

In the instant case, we consider the embedded cost of long term debt as of June 30, 2002 to be a conservatively high estimate of future long term debt costs. As MCI points out, since mid-2002 interest rates have come down sharply. The Federal Reserve Board has lowered short term rates to levels not seen since the 1950s. In this climate, Verizon will continue to refinance as much of its debt as it can without uneconomic prepayment penalties, thus presumably lowering its average embedded cost of debt over time. However, this gradual lowering of the average will likely be tempered by the extent to which existing debt is not susceptible to economic refinancing, an amount that does not appear on this record.

In setting the cost of capital, an inherently forward-looking concept, the Commission typically relies on the weighted mix of actual long term debt, including as it does older issuances at then-prevailing rates, together with more recent issuances at more current rates. This is done in part to avoid a result in which the cost of capital will reflect extreme variations as they may be manifest in the capital markets. The use of the embedded cost of debt on the record in this docket, 7.051%, particularly in the context of a capital structure reflecting some amount of low-cost short term debt, provides a reasonable and conservative estimate of Verizon NH's expected cost of long term debt. We therefore adopt it.

We find that 7.051% is a reasonable estimate of the forward-looking cost of long term debt for Verizon NH, for use in this docket.

E. Cost of Equity

In New Hampshire, the accepted primary method for estimating the expected return on equity is the DCF model. In *Pennichuck Water Works, Inc.*, 70 NH PUC 850 (1985), the Commission found that the DCF method achieves the most reliable and consistent results. In *Pennichuck Water Works, Inc.*, 78 NH PUC 621,627 (1993), the Commission stated that the DCF method continues to be the appropriate way to calculate the cost of common equity but encouraged the use of other methods as a test of the reasonableness of the results. In the latter case, the Commission noted that neither the DCF nor any other method is conclusive, and that judgment, based on reasonableness and fairness to ratepayers and investors, is necessary to arrive at a final decision.

The DCF calculation is sensitive to the assumptions made regarding the inputs to the formula, making judgment necessary for choosing the inputs. The first matter in dispute with regard to the application of the DCF is the selection of companies that are comparable to Verizon. Verizon's witness chose a sample of S&P Industrials, based upon his opinion that the general business market best reflects the risk Verizon NH encounters as a result of the UNE provisioning portion of its business. We are persuaded that the effect of having a small portion of Verizon's business that is associated with the provisioning of UNEs is not commensurate with the level of risk faced by the S&P Industrials. We therefore do not accept the S&P Industrials as a reasonable sample for use in the DCF for determining Verizon's cost of equity.

BayRing/Conversent chose a sample of three RBOCs and a group of electric, gas, and water companies. The OCA's sample of companies included three distinct groups: telecommunications companies, regulated insurance companies, and gas distribution utilities. These samples may be reasonable for use in the DCF, but, in our judgment, it is not necessary to look beyond telecommunications companies to find suitable proxies in this case.

Staff used the ValueLine data on twenty telecommunications companies, then deliberately reduced that number to three firms that witness Schlegel opines are comparable to Verizon NH based on clear and quantifiable distinctions. We approve the approach that Staff employed and find that Mr. Schlegel used reasonable criteria to eliminate unsuitable companies from his sample. Verizon's objection to Staff's sample, based on the small number of proxy companies, is not convincing. Rather than a statistical calculation for which a larger size sample produces results that are more statistically relevant, the DCF is an economic theory for which a more comparable sample, rather than a larger sample, produces results that are more likely to be representative of the subject utility. The size of the sample is irrelevant when, as here, the sample is not random. As a result, we are not persuaded by Verizon's argument that Staff's sample is too small to be comparable. Nevertheless, we find that Staff's process would be improved by limiting its sample to the two RBOCs and eliminating AllTel. Unlike the RBOCs, AllTel does not provide UNEs. Thus, AllTel is less likely than the RBOCs to exhibit the range of operational characteristics of Verizon and will reflect different investor perceived risks. Therefore, based on the evidence before us we find that a sample of two RBOCs is most comparable to Verizon and best suited to application of the DCF in this docket.

Our decision to revise the sample used in this application of the DCF is within our authority to evaluate the evidence before us. The Commission's task of evaluating and reconciling conflicting and complex evidence in the highly technical process of ratemaking calls for the Commission, a quasi-judicial board qualified to evaluate the issues in a specialized field, to exercise its own experience and knowledge. *Legislative Utility Consumers' Council v. PSNH*, 119 N.H. 322 at 335, 402 A.2d 626 at 639 (1979). When doing so by evaluating evidence already in the record, it is not necessary for the Commission to give the parties notice or the opportunity to rebut the conclusion. *Petition of Grimm*, 138 N.H. 42, 53 (1993). As noted in *Appeal of City of Nashua*, 138 N.H. 261, 265, 638 A.2d 779, 781 (1994), a board's findings often portray a variation of the positions proposed by several parties, without mirroring any party's position exactly. In doing so, a board "merely employs its statutorily countenanced ability to utilize its experience, technical competence and specialized knowledge" in evaluating the evidence before it. *Id.* An agency may reject even uncontradicted opinion testimony if its own expertise makes the testimony unpersuasive. *Grimm,* 138 N.H. at 54. The nature of administrative hearings is such that strict, court-sanctioned rules of procedure and evidence do not apply. *NET v. State,* 113 N.H. 92, 101 (1973). Hence, in making its decisions, the

Commission can apply its own expertise to the relevant testimony, exhibits, and records and reports required to be filed by the utility. *Id.* at 102.

The second matter in dispute with regard to the application of the DCF has to do with the growth factor input. Verizon's use of the I/B/E/S consensus analysts' growth estimates for S&P industrials is unacceptable for the same reason using the S&P industrials as a proxy group is not warranted in this case. In addition, the 12.22% growth rate is substantially higher than accepted long-run growth forecasts for the economy as a whole and is not justified for use in the DCF model, especially the one-stage, constant growth form of the model utilized by Verizon.

The inclusion or exclusion of dividends is also a point of debate with regard to the growth factor. Staff argues that Verizon improperly excludes dividends from the growth component of the model. We agree with Staff that Commission precedent reflects the inclusion of dividends in order to produce an accurate return on equity estimate because "the use of any one measure of growth alone excludes information we believe investors consider in making their investment decisions." *EnergyNorth Natural Gas, Inc.*, 78 NH PUC 117, 122 (1993). Pursuant to DCF theory as expounded by Morin, in *Utilities' Cost of Capital* (1984) at p. 124, the expected future cash flows in the form of dividends constitute investment value; dividend growth rates are a more stable measure of investment value than past growth rates of price and earnings per share.

There is no one infallible method of measuring expected growth. As we stated in *Pennichuck Water Works*, 78 NH PUC 621, 628 (1993), in support of our decision to uphold and retain the methodology used and approved in the above-mentioned *EnergyNorth* case, expected growth is "a quantity which lies buried in the minds of investors." We are not persuaded at this time to reconsider our prior determination. In the current economy, we find it reasonable to conclude that the minds of investors consider dividends when making choices. In an investment climate where companies can and have restated earnings, dividends continue to be a sound bellwether of asset values considered by the investment community. We will include dividends within the growth factor in this application of the DCF and accept the 50-50 weighting suggested by Staff and supported by the literature.

A material question presented for decision regarding the application of the DCF for determining Verizon's cost of equity is the form of DCF version to apply. Verizon employed a one-stage DCF version, Staff employed a three-stage version, and BayRing/Conversent employed both single and multi-stage versions. MCI supports both the Staff and BayRing/Conversent calculations. The OCA employed the one-stage version but applied it to multiple sample groups to obtain a range of what it considers to be reasonable cost of equity figures.

Staff testimony supports the view that a three-stage version of the DCF represents a valuable refinement to the DCF method of estimating the cost of capital looking forward over the long term. We agree. Given the computing power available to analysts today, it is possible to more closely match growth rate estimates to varying growth expectations over longer time horizons. Mr. Schlegel used a staged approach to reflect the likelihood that, in the longer term, Verizon's growth rate will converge on the overall growth rate of the economy as a whole. The ability of the three-stage version to represent this convergence is an improvement over the traditional single-stage version, which assumed that early-year growth rates would persist to infinity. It is reasonable to assume that no firm can stay in business over the long term while consistently performing well above or well below the growth rate of the economy as a whole.

The three-stage version may ensure that long term growth rates implicit in the single-stage approach do not exceed the productive capacity of the economy itself. At the same time, a three-stage version ensures that long term growth rates are not estimated to be so low that investors will be under-compensated relative to the market as a whole. The three-stage version could be particularly helpful in situations where there is no regular opportunity to correct an outdated growth assumption.

Verizon argued that the three-stage version produced counterintuitive results: producing a lower cost of equity for companies facing ostensibly higher risk. Staff responded that the three-stage version, as implemented by Staff with equal weight given to both dividend and earnings growth, produced a risk ranking that gave apparently riskier firms a higher cost of equity compared to apparently less risky firms. As Staff indicated at the hearing, its three-stage version produces a cost of equity that is lowest for water companies, higher for electric companies, and highest for Verizon. Tr. Day II. pp. 36-37, 55. Staff satisfactorily explained its calculation in all three instances.

Further, testimony by Staff at hearing demonstrated that Verizon's one-stage application of the DCF model could, under certain conditions, produce illogical results. Both the one-stage and the three-stage versions can produce a counterintuitive relationship between risk, as measured by beta (produced by the CAPM), and the cost of equity. We conclude that the apparent conflict occurs between the CAPM and DCF models and not in the difference between the one-stage and the three-stage versions. Put differently, whether or not the CAPM agrees with the DCF model empirically at any given point in time is irrelevant to the decision of whether the one-stage version should be refined.

Similarly, both the one-stage and the three-stage versions, under certain conditions, can produce a cost of equity below the cost of debt as demonstrated by Dr. Vander Weide in his direct testimony and his criticism of Staff's three-stage version. (Ex. 1, JUW-1 p. 3 and Ex. 3, p. 107.) Whatever the source of these counterintuitive results, they occur in both the one-stage and the three-stage versions and are therefore not driven by the distinction between the two. As we do not question the usefulness of the DCF model in this docket, we do not reject the three-stage DCF model on the basis of these criticisms.

Evaluating the three-stage version of the DCF, we find that refining a model over time is not unreasonable. The model takes account of the fact that the expected growth rates of earnings and dividends quoted by financial publishing companies like Value Line and I/B/E/S may reflect expectations in the medium term but are, by the statements of these publishing companies, not intended to reflect expectations for the long term. The three-stage version takes account of this inherent limitation in the data and ensures that long term growth rates do not exceed the productive capacity of the economy itself. Such a scenario would imply that some companies will grow faster than the economy *ad infinitum*, an implication we cannot accept. At the same time, the three-stage version ensures that long term growth rates are not so low that some investors remain under-compensated. In this manner, the three-stage version strikes a balance that we find is appropriate in this proceeding.

We find the implications of the three-stage version appropriate in this docket. The cost of equity implicit in Staff's three-stage version is slightly above OCA's estimate and slightly below that proposed by BayRing/Conversent. As Staff's estimate is not plagued by the implication that the DCF growth rate can forever diverge from the economy's growth rate, we find Staff's estimate to be most reasonable and therefore adopt it.

The correction the three-stage version makes relative to the one-stage version is small if the one-stage growth rates are close to the sustainable rate to begin with. In this docket, for instance, the difference between Staff's one-stage and three-stage versions amounts to approximately 50 basis points. This shows that Staff's proposed growth rate is reasonable. However, the difference between Verizon's growth rates and the sustainable growth rate is far too great for us to conclude that its growth rate is sustainable indefinitely.

Verizon argued for the inclusion of flotation costs to the cost of equity. Verizon argued that a TELRIC compliant cost of capital should make allowance for such costs as a newly and hypothetically constructed network would require new equity issuances that would have to be financed. We reject the company's reasoning.

We have held previously that lacking any evidence of actual or planned issuances, such costs should not be compensated. *Re: Pennichuck Water Works, Inc.* 70 NH PUC 850, 863 (1985), 70 NH PUC 862. Asked at the hearing, the company witness noted that he did not study the Company's history or plans to issue new equity. Tr. Day 1, April 22, 2003, pp. 43-44. We reject the Company's request to increase the cost of equity to account for flotation costs for the non-UNE portion of the Company's business.

As for UNE rates, TELRIC only assumes the existence of an efficient costing standard. It does not require telephone companies to raise capital to actually go out and build this efficient network. Therefore additional flotation costs would not be incurred.

We now relate our findings thus far to the overall question of cost of equity. We find that the most reasonable method to determine the cost of equity on this record is to use the cost of equity estimated by Staff based on its mix of earnings and dividend growth estimates for the revised sample of proxy RBOCs, applied in the three-stage DCF version, with the first stage ending in year five and the third stage beginning in year eleven. This method produces a cost of equity for Verizon NH of 9.82%. We find that this estimate of the cost of equity is reasonable for Verizon NH and we adopt it.

F. Overall Weighted Average Cost of Capital

Using an imputed capital structure of 45% equity, 53% long term debt, and 2% short term debt, a long term cost of debt of 7.051%, a short term cost of debt of 2%, and a cost of equity of 9.82%, we find that the overall weighted average cost of capital for Verizon NH is 8.2%.

Based upon the foregoing, it is hereby

ORDERED, that for the purpose of calculating Verizon's cost of capital the company shall be viewed as a whole to determine an overall cost of capital that shall apply to all jurisdictional cost studies; and it is

FURTHER ORDERED, a capital structure of 45% equity, 53% long term debt and 2% short term debt shall be imputed for the purpose of calculating an overall cost of capital; and it is

FURTHER ORDERED, that a cost of long term debt of 7.051% and a cost of short term debt of 2% shall be utilized for the purpose of calculating an overall cost of capital; and it is

FURTHER ORDERED, that the cost of equity shall be 9.82%, for the purpose of calculating an overall cost of capital; and it is

FURTHER ORDERED, that the overall weighted average cost of capital for Verizon shall be 8.2%; and it is

FURTHER ORDERED, that Verizon NH shall file revised SGAT tariffs to reflect the cost of capital as found in this Order by March 16, 2004.

By order of the Public Utilities Commission of New Hampshire this sixteenth day of January, 2004.

Thomas B. Getz Chairman	Susan S. Geiger Commissioner	Graham J. Morrison Commissioner

Attested by:

Debra A. Howland
Executive Director & Secretary

Tab R

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PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 2nd day of January, 2004.

CASE NO. 03-0353-W-42T

WEST VIRGINIA-AMERICAN WATER COMPANY
Tariff Rule 42 application to increase
water rates and charges.

COMMISSION ORDER

The Commission is herein presented with the first fully litigated rate case brought by the West Virginia American Water Company (Company) since 1994. After an evidentiary hearing and review of all submitted testimony and argument, the Commission herein authorizes a return on equity of 7.00%, an overall return of 6.63, on a rate base of approximately $394,150,000, and a revenue requirement of approximately $98,885,000.

Procedure

On March 11, 2003, the Company tendered for filing revised tariff sheets reflecting increased rates and charges of approximately 16.4% annually, or $15,550,687, for furnishing water utility service to approximately 164,000 customers in Boone, Braxton, Cabell, Clay, Fayette, Harrison, Kanawha, Lewis, Lincoln, Logan, Mason, Mercer, Putnam, Raleigh, Summers, Wayne and Webster Counties, to become effective on April 11, 2003. In addition to increased commodity rates, the filing requested the institution or increase of certain non- commodity charges, such as the delayed payment penalty, a returned check charge, a tap fee, a reconnection fee, and a leak adjustment rate (collectively referred to as "cost causer" or Customer Specific tariff items).

In addition to its own customers, customers of the following utilities or entities would be directly or indirectly affected by the rate application because these utilities or entities, under agreements approved by the Public Service Commission, are charged water rates which are based on the Company's rates, either in whole or in part: Boone County Public Service District, Cumberland Road Public Service District, the Town of Danville, the Town of Eleanor, Jumping Branch-Nimitz Public Service District, the Kanawha County Regional

Development Authority, Lashmeet Public Service District, the Lewis County Economic Development Authority, New Haven Public Service District, Oakvale Road Public Service District, the Putnam County Building Commission, Putnam-Union Public Service District and Salt Rock Water Public Service District.

In its filing the Company asserted that it had complied with the notice requirements of Rule 10.1.b of the Commission's Rules for the Construction and Filing of Tariffs (Tariff Rules).

The Commission notes that throughout the course of this proceeding it has received a large number of letters filed in protest of the Company's proposed rate increase. The volume of letters prompted the a reasonable level of profit. However, the Commission intends to examine carefully each cost element that the Company believes is driving its request for a rate increase.

The CAD's request that the Commission should deny any increase in this case until such time as the income of the Company's customers improves or the Company can show that it requires additional revenue to avoid financial distress shall be denied.

RATE OF RETURN

Return on Equity

The Public Service Commission has long held that rates should be set which allow a public utility an opportunity to earn a sufficient level of revenue that will enable the utility to attract capital in the competitive money market, yet which also balance this ability with the interest of the consuming public in receiving fair and reasonable rates. Bluefield Water Works and Improvement Company v. Public Service Commission, 320 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591, 64 S.Ct. 281 (1944); Permian Basin Area Rate Cases, 390 U.S. 747, 88 S.Ct. 1344 (1968); Monongahela Power Company v. Public Service Commission, 276 S.E.2d 179 (W. Va. 1981).

As we previously stated, rate cases in general require the Commission to consider the interest of not only the investors, but also the consumers when determining a reasonable rate of return. Case No. 94-0138-W-42T, at pp. 47-48. The rate of return should be sufficient to assure confidence in the financial condition of the utility and to enable to the utility to maintain its credit and to raise money for the proper discharge of its duties. Id.

That said, the determination of an appropriate cost of common equity is generally one of the most contentious issues in a rate proceeding and it is certainly true in this case. It is not unusual to find that the witnesses presenting testimony on the cost of common equity capital use the same or similar methodologies, but end up with significantly different results. Indeed, this Commission has noted in the past that, "all of these methods represent artful analyses rather than exact science and none of them can be said to produce a finite "correct answer" to the exclusion of the others. These studies are useful in providing trends and data that is susceptible to interpretation, but the ultimate answer regarding investor expectations must rely heavily on the judgement of the Commission." Appalachian Power Company, Case No. 91-026-E-42T (Commission Order, November 1, 1991), at p. 4.

In determining the cost of common equity for a regulated utility, it is generally accepted that one must look at investor expectations of that utility's stock price, earnings, dividends and book value, among other things. When a stock is publicly traded such a

determination benefits from observation of the stock's experience in the market place. However, the Company's stock is not publicly traded. Instead, all of its stock is owned by its parent company and, accordingly, the cost of equity capital witnesses in this case had to make various assumptions when determining the appropriate return on equity.

The following is an overview of the positions of the return on equity witnesses:

Paul R. Moul presented evidence on behalf of the Company on the issue of rate of return on equity. Mr. Moul recommended that the Company be afforded an opportunity to earn a rate of return on common equity within the range of 10.00% to 11.50%. The Company then elected to seek a return on common equity of 10.25%. Direct Testimony, Paul R. Moul, p.1.

Mr. Moul relied upon four methodologies to arrive at his return recommendation. He used a Discounted Cash Flow Model (DCF), Risk Premium Analysis (RP), a Capital Asset Pricing Model (CAPM), and a Comparable Earnings Analysis (CE). In determining a reasonable range for return on common equity, he analyzed a proxy group of six water companies and a second proxy group of ten natural gas utilities. Based upon his utilization of the DCF and RP analyses by themselves he arrived at his recommendation. More specifically, his findings were:

	Water Group	Gas Group	Average
DCF	9.52%	11.47%	10.50%
RP	11.75%	12.00%	11.88%
CAPM	14.65%	14.69%	14.67%
CE	14.80%	14.80%	14.80%

Direct Testimony, Paul R. Moul, p. 4.

The average of the DCF and RP models for the Water Group was 10.64%. With the addition of the Gas Group, the average for those two models rose to 11.19%.

The DCF model seeks to determine the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. According to Mr. Moul, the DCF methodology has limitations. Direct Testimony, Paul R. Moul, pp. 19-33. The DCF model has two major components: the dividend yield and the expected or reasonable growth rate. Mr. Moul utilized 5.25% as the growth rate for the Water Group and 5.75% for the Gas Group. He used 3.73% and 4.99% as the dividend yield components

for the Water Group and the Gas Group respectively. With these factors, he also adjusted the outcome of the model upward with an adaptation of his interpretation of the Modigliani and Miller (M&M) theories. Mr. Moul argued that DCF determined costs of equity should be adjusted to reflect the role of leverage in a firm's capital structure. The M&M theory attaches higher risk to investments which are more highly leveraged with debt. Mr. Moul's adaptation of this theory assumes that a premium should attach to the DCF model results which would reflect the additional risk resulting from the utilization of a book value capital structure, rather than a market value capital structure. Direct Testimony, Paul R. Moul, pp. 30-31.

RP analysis is the determination of the cost of equity capital by reference to corporate bond yields to which a premium is added to reflect the increased risk of common equity over debt capital. Mr. Moul's study indicated that 7% is a reasonable bond yield to estimate the prospective long-term debt cost rate for an A-rated public utility bond. Direct Testimony, Paul R. Moul, p. 33. He also determined that a reasonable risk premium for the water group is 4.75% and the corresponding risk premium for the Gas Group would be 5.00%. Direct Testimony, Paul R. Moul, p. 37.

CAPM takes the yield on a risk-free interest bearing obligation and adds to it a return representing a premium that is proportional to the systematic risk of an investment. There are three components to the model, the risk free rate of return, the beta measure of systematic risk, and the market risk premium. Mr. Moul utilized yields on long-term Treasury bonds for his risk free rate of return. His analysis used a 5.00% risk free rate of return. He utilized a "leveraged beta" measure of systematic risk of .77 for the Water Group and a beta of .84 for the Gas Group.

Randall R. Short provided testimony on return on common equity on behalf of the CAD. He utilized the DCF and CAPM analyses to arrive at his recommendation. He recommended 8.25% as a reasonable rate of return on common equity for the Company, a return selected from a range of reasonableness between 8.20% and 8.50%. Direct Testimony, Randall R. Short, p. 2. His DCF analysis produced a dividend yield component of 3.2% and a dividend growth rate range of 5.0% to 5.25%. Direct Testimony, Randall R. Short, p. 27. This was extended to a within range average of 8.33% as a fair and reasonable rate of return on common equity.

Mr. Short's CAPM analysis started with 1.15% and 5.21%, representing short-term three month U.S. Treasury bills and thirty year U.S. Treasury bonds. Mr. Short utilized a beta of 0.62. He based his beta upon the Value Line beta coefficients for the companies in his water utility group. Value Line betas are derived from a regression analysis between weekly percentage changes in the market price of a stock and weekly percentage changes

in the New York Stock Exchange Composite Index over a period of five years. He applied the beta to both geometric and arithmetic average market risk premiums for large company stocks, which he obtained from the 2003 Yearbook, reported by Ibbotson Associates. His calculations produced a second range of reasonable rates of return on common equity spread between 5.12% and 9.18%, with an average being 7.20%. Direct Testimony, Randall R. Short, p. 31.

Diane Davis Calvert presented cost of equity testimony on behalf of the Staff. Staff recommends 6.67% rate of return on equity based on a range of 5.66% to 7.34%. Staff relied upon three approaches to determine a rate of return on common equity. It utilized the DCF and CAPM models as well as an end result analysis to assure that the Company would be given a reasonable opportunity to generate sufficient revenue to pay its operating and maintenance expenses, to pay its interest expense, and to internally generate an adequate cash flow for capital improvements.

In Ms. Calvert's DCF analysis, she determined an average dividend yield of 3.10% and an expected dividend yield growth rate of 3.74% for a total expected return on common equity of 6.84%. Her calculations were based upon a sample group of seven water companies. Direct Testimony, Diane D. Calvert, pp. 7-8, Appendix DDC-1, Schedule 3.

Ms. Calvert's CAPM analysis utilized historic and projected 13-week U.S. Treasury bill rates as the risk free return component. Her expected rate of return on the market was calculated by determining the difference between the arithmetic mean of the return on common stocks, as measured by the Standard & Poor's 500 Composite Index, and the risk free T-Bill rate. The risk free return component was 1.458%. The market premium or expected rate of return was 8.4%. Ms. Calvert utilized beta coefficients ranging from .50 to .70, with an average beta of .60. The betas were taken from Value Line Investment Survey, August 1, 2003. The application of these values to the CAPM formula produced rates of return ranging from 5.66% to 7.34% with an average of 6.50% as a reasonable rate of return on equity. Direct Testimony, Diane D. Calvert, pp. 8-10, Appendix DDC-1, Schedule 3.

Ms. Calvert applied her recommended rate of return on equity to the Company's rate base, operating and maintenance expenses, debt expense, dividend expense payout history and internally generated funds historical requirements to determine whether the recommended rate of return on common equity was reasonable. Her recommended return of 6.67% will provide long-term interest coverage of 2.14 times and total interest coverage of 2.10 times. The Company's Indenture of Mortgage requires debt coverage of 1.5 times the long-term interest expense. During the last five years, the Company has averaged a 75.98% dividend payout rate. The Staff recommended rate of return would allow for a

dividend of $7.966 million at the 75.98% dividend payout rate. The Staff's recommendation will also provide for the internal generation of 95.66% of the average 2004-2005 projected total capital expenditures of the Company. Direct Testimony, Diane D. Calvert, pp. 14-16, Appendix DDC-1, Schedule 5, Sheets 1-3, Schedule 6, Sheets 1-3.

While the Cities did not provide a numerical analysis of the appropriate return on equity, they did submit an extensive argument on the issue. The Cities noted that in the Company's last fully litigated cost of equity case (the 1994 case) the Commission set 10.65% as the Company's equity rate. Since that time, other investments have fallen between 260 and 400 basis points. "Yet Mr. Moul's cost of equity range actually contemplates that while the investment market falls across the board by 260 - 400 basis points, WVAWC's 10.65% of 1994 ought to be raised to as much as 11.5% in 2003." Initial Brief of the Cities at p. 15.

The Cities also cited Permian Basin, the more recent United States Supreme Court case on rate of return. The Cities noted that therein the Court followed Bluefield and Hope, and additionally stated:

> The Commission . . . is instead obliged at each step of its regulatory process to assess the requirements of the broad public interests entrusted to its protection by Congress. Accordingly, the 'end result' of the Commission's orders must be measured as much by the success with which they protect those interests as by the effectiveness with which they 'maintain . . . credit and . . . attract capital.' [Permian Basin at pp. 790-791.]

The Court specifically stated a list of three 'determinations" for a reviewing body to make:

> First, it must determine whether the Commission's order, viewed in light of the relevant facts and of the Commission's broad regulatory duties, abused or exceeded its authority. Second, the court must examine the manner in which the Commission has employed the methods of regulation which it has itself selected, and must decide whether each of the order's essential elements is supported by substantial evidence. Third, the court must determine whether the order may reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors for the risks they have assumed, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable. [Permian Basin at pp. 791-792.]

The Cities continued by noting that in Monongahela Power Co., the West Virginia Supreme Court cited standards set forth in Bluefield and Hope but then set forth in its entirety the standard of review in Permian Basin. The Court went on to say Permian Basin essentially incorporates the just and reasonable rate requirement set by West Virginia Code §24-2-4. Thus, the Cities argued, Permian Basin, with its emphasis on providing protection to the relevant public interests, is the guiding principle as set forth by this State's highest court. Cities Initial Brief, November 3, 2003.

The wide range of recommended equity costs in these proceedings demonstrates why the Commission has, on numerous occasions, stated that recommendations of expert witnesses on cost of common equity are useful as guides, but, due to the subjective nature of the various inputs into each expert's recommendation, the determination of an appropriate cost of common equity for a utility must rest principally with the Commission's best judgement. See, The Potomac Edison Company, Case No. 79-230-E-42T, (Interim Order, November 21,1979) at p. 7; Virginia Electric and Power Company, Case No. 79-040-E-42T, 67 ARPSCWV 277 (Final Order, February 1, 1980); Monongahela Power Company, Case No. 80-058-E-42T, (Interim Order, July 18, 1980) at p. 8; Monongahela Power Company, Case 90-504-E-42T (Commission Order, June 11, 1991) at p. 24; GTE South, Inc., Case No. 90-522-T-42T (Commission Order, May 31, 1991) at p. 17; Appalachian Power Company, Case 91-026-E-42T (Commission Order, November 1, 1991) at p. 4; Mountaineer Gas Company, Case No. 93-0005-G-42T (Commission Order, October 29, 1993) at p. 9.

The Commission is presented with a range of 6.67% at the low end to 10.25% at the high end of the parties' recommendations. While the 6.67% recommended by Staff is hotly contested by the Company, there is little contest in the way of charges of errors or inconsistencies. We do not find any errors in Staff's analysis or attempts to throw out data that would inflate Staff's recommendation. On the other hand, we have several problems with the Company's position that attempts to elevate the high end of our range of considerations on this issue using methods that have never been adopted by this Commission or that attempt to effectively leverage-up the rate base of the Company in the form of a rate of return component that offsets the effect of our long standing policy of using original cost rate base.

The Commission believes that Mr. Moul, testifying on behalf of the Company, has simply stretched his analysis upward at every opportunity to produce a recommended range of returns on equity that are clearly excessive and not consistent with investor expectations. For example, his choice of a Gas Group results in higher return targets in nearly every analysis that he made. The most striking example of this is the comparison of his water group DCF, where he arrives at a 9.52% recommended Return on Equity and his Gas Group DCF, where his answer is 11.47%. On this point, regarding a reliance on the Gas Group,

the Commission concurs with the Cities' argument regarding the Company's use of a Gas Group in the determination of its return on equity: The Company used far riskier ventures in natural gas companies with returns substantially higher than the Water Group and claimed that the groups were comparable. But natural gas investment is far riskier and not comparable to water. The Cities Reply Brief at p. 7.

Additional examples of the Company witness raising his sights above what a reasonable analysis produces can be found in the market value adjustments that he makes. His water group DCF analysis would be only 8.98%; however, he leverages this number up by 54 basis points, or .54%, to reflect the fact that stockholders pay market prices for stock and those market prices may exceed the book value of a utility's rate base. Thus, the Company asks us to effectively depart from our long-standing use of an original cost rate base. We could do this by simply applying the derived rate of return, before market price leveraging, to an inflated rate base that exceeds book value or, in the alternative chosen by the Company, we can continue to use original cost rate base and apply an inflated rate of return to that rate base.

The Company witness has further inflated his DCF analysis by using earnings per share growth rates rather than the dividend growth rates that have been historically used by the Commission in its DCF analysis. The Company witness ' water group dividend growth rate is either a 2.5% historic growth rate or a 2.83% projected growth rate. While there can be disagreement regarding the choice of historic or projected growth rates in the DCF formula, clearly there is not a huge difference in either dividend growth rate. However, the Company witness stretches his recommendation by turning to growth in earnings per share. Here, he takes a measure that has not been historically used by this Commission and suggests that we consider it in evaluating a DCF indicated return on equity. The historic earnings per share he uses is 3.6%, a full 110 basis points above the historic growth in dividends. His projected growth in earnings per share jumps to 6.71%, or more than 320 basis points above the historic growth in dividends.

Looking at the Company witness' sample water group, and using his yield plus historic growth in dividends results in a DCF indicated return on equity of 6.23%. Even using his historic growth in earnings per share produces only an indicated return on equity of 7.33%.

The Company witness' other models for determining a return on equity suffer from a similar effort to simply raise the numbers. For example, in his Capital Asset Pricing Model, he incorporates a projected market premium of 14.71% based on a projected market return of 19.71% less a risk free rate of 5%.

This is a full 830 basis points above his historical market premium of 6.4% based on a historical market return of 12.2% less a

historical long-term treasury rate of 5.8%. As a further example, in his Capital Asset Pricing Model, he applies his market value adjustment to leverage his water group beta from .6 to .77. As we have explained above, this market value adjustment is completely unacceptable and unreasonable.

In addition, the Commission agrees with the Staff that the CAPM depends on a determination of an objective and sustainable risk free component. The Company seeks a risk free component of 5%, based on long term treasury bonds. In today's market, with secured savings accounts receiving annual interest of less than 1%, with secured Certificates of Deposit receiving annual interest around 2%, and with short term treasury bonds yielding less than 2%, we simply do not find any credibility in the Company witness' support of a 5% risk free component.

Looking at the Company witness' CAPM stripped of his efforts to leverage unrealistic rates of return through his adjustment to attempt to compensate investors for the fact that they may be paying market prices in excess of the book value rate base used by a regulatory commission, we see a water group beta of .6. Even accepting his excessive risk free component of 5%, his CAPM at a .6 beta would be 8.84%, far below the 10.00% to 11.5% rate of return on equity range which he supports. More importantly, adjusting his CAPM analysis to reflect a more realistic risk free component even using 2% as a short term rate (which is higher than the short term rate used by Staff) results in a return on equity of 7.04%.

Clearly, while we must acknowledge the Company witness' recommendations as being the high end of the range of recommendations made in this case, the Commission finds significant subjective modifications to the empirical data adopted by the Company witness that not only render his recommendations as being on the high side, they simply place his 10.0% to 11.5% return on equity recommendation outside of any range of reasonableness.

With regard to the CAD witness' recommendation of an 8.25% return on equity, the Commission also finds that Mr. Short fails to support some of the components of his recommendation. We find this to be particularly troublesome with regard to his use of multiple growth rates in his DCF model and his use of multiple risk free components in his Capital Asset Pricing Model. Historically, the Commission has used growth in dividends as the growth rate component in a DCF model. We believe that this is consistent with the use of dividend yield in the model. There is a balance between investor expectations of dividends and the market price. Specifically, we do not find support for the growth rate in the DCF analysis recommended by Mr. Short, and believe that it represents a highly subjective selection from among a number of growth rate considerations. In his CAPM, Mr.

Short again mixes a risk free component based on short-term three month U.S. Treasury bills and thirty year U.S. Treasury bonds. The Commission finds that his use of excessive growth rates as part of his analysis and his use of a 30 year U.S. Treasury bond rate, which we do not consider to be a reasonable measure of the risk free component of the Capital Asset Pricing Model, similarly renders his recommend 8.25% cost of equity to be too high.

Turning to the Staff's recommended return on equity, the Commission finds that the 6.67% recommendation is based on the most realistic and objective measures of investor expectations and market risks. We also find that the end result tests performed by Staff are not, as the Company asserts, the means to the end goal of determining a fair and reasonable rate of return. Instead, these end result analyses help the Commission to determine if a given capital structure, debt costs, and return on equity produce sufficient interest coverage, dividend potential, and internal cash flows to enable the Company to meet the comparable earnings, financial integrity, and capital attraction tests set forth in the Bluefield and Hope cases. Indeed, upon a review of the end results of the Staff's recommended return on equity, particularly with regard to the net income available for preferred dividends and remaining for common stock holders after payment of preferred dividends, the Commission finds that a return on equity in excess of the Staff's recommended 6.67% is needed.

Upon consideration of the testimony and briefs of the parties, the Commission shall set a return on equity capital at a rate of 7.00%. The Commission's rate is at the lower end of the scale as presented by the parties but believes its decision adequately balances the concerns of the Company regarding investor perceptions of the riskiness of the water industry with the need to ensure that the ratepayers pay rates reflecting no more than a fair rate of return, and also will be sufficient to comply with the Hope and Bluefield tests set forth previously in this discussion.

Capital Structure and Resulting Rate of Return

The capital structure issue addresses the sources of capital supporting the net assets (rate base) of the utility. A company's capital structure will normally depict the amount of capital acquired by an entity through retained earnings, other paid in capital contributions from stockholders, the issuance of debt, and the issuance of stock. Capital structure quantifies short-term and long-term debt, as well as preferred and common equity - and establishes a relationship between the various capital sources for subsequent use in a formulaic approach to determine a composite cost of capital.

To determine cost of capital, each type of capital is calculated as a percentage of the total capital structure. The cost rate for each type of capital (long term debt, short term debt, preferred stock, and common stock) is then multiplied by that type of capital's percentage

of the total capital structure to derive a weighted cost of capital for each type. Those weighted costs are then added to reach a total cost of capital or rate of return. The inclusion of short-term debt in the capital structure is a contentious one because the inclusion of short- debt in the capital structure lowers the overall cost of capital and rate of return. By including short-term debt in the capital structure, the percentage of total capital for the higher cost forms of capital is reduced and, therefore, the overall cost of capital for a company is also reduced.

Testimony and other evidence pertaining to capital structure was introduced by three expert witnesses in this proceeding, Michael A. Miller on behalf of the Company, Randall R. Short for the CAD, and Diane Davis Calvert for Staff.

In this case, the Company used a test year ending December 31, 2002. The Company began its analysis using a capital structure for the twelve months ending coincidentally with its test year. The 2002 capital structure was then adjusted to reflect the Company's financial activity projections for 2003 and its estimate for the level of retained earnings through 2003. The Company included post-test year adjustments and argued that such an adjusted capital structure would be in place at the time the rates were placed into effect. Direct Testimony, Michael A. Miller, p. 2. These adjustments resulted in a decrease in short-term debt from $20,327,894 to $15,374,000, a reduction of $4,953,894. Long-term debt was reduced from $224,801,974 to $224,055,276, a reduction of $746,698. Preferred equity was reduced from $2,250,000 to $2,227,704, a reduction of $22,296. Common equity was increased from $162,182,738 to $164,448,999, an increase of $2,266,261. The increase in common equity reflects undistributed net income or retained earnings. See Company Exhibit MAM-1. The Company exhibited the following percentages and costs associated with the various classifications of debt and equity capital sources:

Capital source	% of Structure	Effective Cost
Short-term debt	3.786%	3.50%
Long-term debt	55.172%	6.73%
Preferred stock	.549%	8.57%
Common stock	40.494%	10.25%

Miller Direct, MAM-1, Page 1 of 3.

The Company projected a cost rate of 3.50% for short-term debt, relying upon a Value Line projection for 2004 - again, the time frame in which the proposed tariff rates will become effective. The amount of the short-term debt was adjusted downward to reflect the

repurchase of a portion of that short-term debt with cash generated in 2003. The cost of long-term debt was calculated by determining the actual cost of fourteen issues of general mortgage bonds varying in interest rates from 10% to 4%. This amount was adjusted to reflect sinking fund payments during 2003. The cost of preferred stock was determined by calculating the cost of the series of preferred stock issue with interest rates varying from 4.625% to 8.85%. This amount was also adjusted to reflect sinking fund payments. Mr. Miller's cost of common equity was selected from the range of returns recommended by the Company's witness Paul Moul. Mr. Miller selected 10.25% from the range 10.00% to 11.50%. Direct Testimony, Michael A. Miller, p. 7.

The Company argued that Staff would have the Company incur short-term debt for no reason other than the fact that short-term interest rates are low. The Staff does not indicate to what use the borrowed funds should be put, other than to marginally reduce the weighted cost of capital. Needlessly incurring debt will increase the Company's total capitalization and interest expense, to the ultimate detriment of the ratepayers. Company Reply Brief at p. 10.

The Company acknowledged that the anticipated rate for short-term debt reflected in its filing is too high in light of the most recent actions of the Federal Reserve and other market conditions. The Company was therefore willing to accept the CAD's short-term debt rate of 1.462% and recommended the following adjusted capital cost components and overall rate of return:

Class of Capital	Amount	% of Total	Effective Cost	Weighted Cost
Short-term Debt	15,374,000	3.786%	1.46%	0.06%
Long-term Debt	224,055,276	55.172%	6.73%	3.71%
Preferred Stock	2,227,704	0.549%	8.57%	0.05%
Common Equity	164,448,999	40.494%	10.25%	4.15%
Total Capital	406,105,979	100.000%		7.90%

Company Initial Brief, November 3, 2003 at pp. 10-12.

Randall R. Short, on behalf of the CAD, argued for a different capital structure. He recommended that the Commission utilize the following structure:

Capital Source	% of Structure	Effective Cost

Short-term debt	4.25%	1.462%
Long-term debt	55.18%	6.726%
Preferred stock	0.55%	8.550%
Common stock	40.02%	8.250%

Direct Testimony, Randall R. Short, p. 15.

Mr. Short utilized an average actual capital structure. His recommended structure was determined by averaging the Company's actual reported capital structure over the four quarters ending June 30, 2003. Direct Testimony, Randall R. Short, pp. 15-16. There were, however, substantial differences between Mr. Short and the Company with regard to the cost of short-term debt and common equity. Mr. Short recommended 1.462% as the short-term debt cost, rather than the 3.50% proposed by the Company. The CAD witness differed in approach from the Company by utilizing an average cost of short-term debt for the period January 2003 through June of 2003. Mr. Short asserted that this treatment was correct as short-term debt costs have declined significantly over the past two years, ending in an actual short-term debt cost rate to the Company of 1.24% as of June 30, 2003. Mr. Short disputed the Company's use of 3.5%, pointing out that it is substantially higher than any short-term rate the Company has incurred during the past two years and does not reflect current or projected rates. In support of this position, he testified that the August 1, 2003 issue of Blue Chip Financial Forecasts reported commercial paper rates varying from 1.0% to 2.2% for the next six quarters. Direct Testimony, Randall R. Short, pp. 17-18.

The CAD argued that the conjectural nature of the Company's hypothetical capital structure can be seen in the Company's projected cost rate for short-term debt. The CAD asserted that the Company projected a cost rate for short-term debt of 3.5%, Tr. Vol. I, p. 184. That amount is almost three times the Company's current cost of short-term debt (1.2%), and more than double the historic rates used by Staff and CAD (1.4% and 1.46% respectively). Tr. Vol. IV, p. 167. The CAD further asserted that short-term debt costs have declined significantly over the last two years as the Federal Reserve Board has attempted to stimulate economic activity by reducing the federal funds rate. Use of the most recent actual capital structure in setting rates avoids rates based on speculation and the CAD urged its adoption in this case. CAD Initial Brief at pp. 11-12.

The Staff's testimony regarding capital structure was presented by Diane Davis Calvert. She recommended that the Commission use the Company's actual capital structure as of December 31, 2002 (the end of the test year), with two adjustments. Ms. Calvert used long-term debt and preferred stock balances net of their unamortized issuance expenses. She also recommended that the level of short-term debt be adjusted to reflect the average balance outstanding during the test year. The Staff's witness recommended that the Commission adopt the following capital structure:

Capital source	% of Structure	Effective Cost
Short term debt	4.63%	1.40%
Long term debt	55.01%	6.73%
Preferred stock	.55%	8.56%
Common stock	39.81%	6.67%

Direct Testimony, Diane Davis Calvert, Appendix DDC-1, Schedule 1.

Ms. Calvert calculated her short-term debt percentage by determining the average daily balance outstanding in short-term debt during the test year. Direct Testimony, Diane D. Calvert, p. 3; see also

Schedule 1, Sheet 2. The cost of her short-term debt, 1.40%, represents the actual average cost incurred by the Company for the latest three months available at the time of the preparation of her testimony - April through June of 2003. She argued that using the most recent cost information available is consistent with adjusting test year expenses for known and measurable changes. Direct Testimony, Diane D. Calvert, p. 3.

The Commission notes that the other parties did not provide a detailed analysis of capital structure and rate of return although the Cities adopted the Staff's capital structure and corresponding calculation of rate of return. Cities Initial Brief at p. 26.

The chart below shows the respective positions of the parties:

	CompanySee FootNote [2]		CAD		Staff	
Type	% of Total	Cost Rate	% of Total	Cost Rate	% of Total	Cost Rate
Common Equity	40.494	10.25%	40.017	8.250%	39.81	6.67%
Preferred Stock	0.549	8.57%	0.552	8.550%	0.55	8.56%
Long Term Debt	55.172	6.73%	55.180	6.726%	55.01	6.73%
Short Term Debt	3.786	1.46%	4.251	1.462%	4.63	1.40%
Return		7.90%		7.122%		6.47%

The Commission has reviewed the arguments presented by the parties. The Commission also appreciates the criticisms the parties have levied upon the respective arguments of opposing parties on these issues. The Commission is of the opinion that it would be on defendable ground were it to fully adopt the absolute position of CAD, the Company, or Staff. Clearly, the components of capital, stated on a percentage basis, as recommended by Staff, CAD, and the Company are very close. The Staff's position is the most defensible from the standpoint of being tied to a known structure at a point occurring within the test year. Furthermore, the Staff's proposed modification to this point-in-time approach as it relates to short-term debt is reasonable. Clearly, unlike the other components of capital structure which are not likely to shift significantly from month to month, short- term debt can change significantly from month to month and the choice of an average rather than a point-in-time snapshot of short-term debt is reasonable. However, the Commission concludes that based on the record in this case each of the capital structures are so similar that none would be determined to be imprudent.

In such a position, the Commission believes the wisest choice is to look for a compromise position or middle ground between the recommendations offered. Indeed, the CAD position represents a middle ground between the position of the Company and Staff with regard to capital structure. However, we shall not simply adopt the CAD position as a compromise. In this case, for the capital structure, and no other issue, the Commission shall split the difference between the positions of the Company and Staff. With regard to cost of capital rates, there is little difference on any of the capital components other than short term debt and equity. We have already explained that we are adopting a return on

equity of 7.0%. With regard to short term debt, we shall adopt the Staff's recommended 1.40%. Accordingly, the Commission shall utilize the following capital structure, cost of capital and overall rate of return:

	DECISION		
Type	% of Total	Effective Cost	Weighted Cost
Common Equity	40.15	7.00%	2.81%
Preferred Stock	.55	8.56%	.05%
Long Term Debt	55.09	6.73%	3.71%
Short Term Debt	4.21	1.40%	.06%
Rate of Return			6.63%

OPERATION AND MAINTENANCE AND OTHER EXPENSES

There are two Operation and Maintenance (O&M) issues that reverberate throughout several of the other O&M issues in this case: (1) Capitalized Payroll and (2) the number of Company employees. The Commission shall address these items first so that later issues (e.g., group insurance, OPEB's, pension costs, ESOP, and 401(k) expenses, and a number of tax calculations) contingent upon Capitalized Payroll and level of Company employees may be resolved in an abbreviated manner.

Capitalized Payroll Ratio

Other than return on equity, the capitalized payroll issue has the largest impact on the Company's revenue requirement in this case. The Company has requested that its capitalized payroll _ that is, the percentage of payroll dollars that will be capitalized, as opposed to expensed _ be set at 23.19% in this case, a reduction from the 28.58% which was actually capitalized in the test year. Company Exhibit MAM-B at 16. The Company argues in its Initial Brief that a blind adherence to the test year capitalized payroll ratio of 28.58% will limit the Company's reasonable opportunity to achieve whatever authorized rate of return the Commission decides is appropriate in this case. The Company argues that it is not going to capitalize this amount of labor in the 2004 rate year given its demonstrated construction requirements and capital spending plan. If the level of capital payroll reflective of the rate year is not recognized, the Company must absorb this difference in its financial performance or offset the shortfall by making reductions in other areas. Company Initial Brief.

Staff argued in its Initial Brief that Staff and the Company have consistently used historical test year percentages in its analysis of going level payroll. Staff believes that the Company's use of estimated expense/capitalization ratios would violate the matching principal and further argued that the Company's use of capital budgets as a measure of going level payroll violates the known and measurable standard. Direct Testimony, Kellmeyer, p. 6.

The CAD argued in its Initial Brief that the test year ratio be retained, based on evidence showing that the Company's construction budget for the foreseeable future will remain relatively stable and that any forecasts are merely speculative. The CAD notes that a lower labor capitalization ratio results in a higher labor expense ratio and higher revenue requirements to be paid by current ratepayers. To avoid this, the CAD recommends that rates in this proceeding should be set based on test year actual expense/capitalization ratios.

Utilizing the Company's ratio of 23.19% steps outside of the 2002 test year and violates the matching principle. Furthermore, even if the percentage capitalized does decrease due to lower construction activity, such lower construction activity may result in lower total payroll costs. Thus, the Company's argument that the actual 2004 capitalization ratio, which is lower than the amount reflected

Tab S

Or. Admin. R. 860-012-0100 Grant Eligibility (Precertification and Case-Certification)

(1) Definitions:

(a) "Agreement" means a Commission approved agreement under ORS 234, OR Laws 2003 between a utility providing electricity or natural gas and a not-for-profit organization that represents broad customer interests in Commission regulatory proceedings.

(b) "Grant" means financial assistance to an intervenor under the terms of an agreement.

(2) General. Upon Commission approval of an agreement, the Commission shall apply the qualifications set forth in this rule to determine eligibility for a grant. Only parties that are precertified, or parties that become case-certified for a particular proceeding, will be eligible to receive grants under an agreement. The terms of an agreement will be binding on all organizations seeking a grant under that agreement and will be followed by the Commission in administering the agreement.

(3) Precertification. The Commission will precertify organizations meeting the criteria of subsection (3)(a) or (3)(b) as eligible to receive grants. Once precertified, an organization will remain precertified unless the Commission decertifies the organization under OAR 860-012-0190.

(a) The Citizens' Utility Board of Oregon (CUB), as a representative of residential customers; or

(b) Not-for-profit organizations that meet all of the following criteria:

(A) A primary purpose of the organization is to represent utility customers' interests on an ongoing basis;

(B) The organization represents the interests of a broad group or class of customers and those interests are primarily directed at public utility rates and terms and conditions of service affecting that broad group or class of customers, and not narrow interests or issues that are ancillary to the representation of the interests of customers as consumers of utility services;

(C) The organization demonstrates that it is able to effectively represent the particular class of customers it seeks to represent;

(D) The organization's members, who are customers of one or more of the utilities that are parties to the agreement, contribute a significant portion of the overall support and funding of the organization's activities in the state; and

(E) The organization has demonstrated in past Commission matters the ability to substantively contribute to the record on behalf of customer interests.

(4) Case-Certification. Organizations meeting the following criteria may be case-certified by the Commission to be eligible to receive a grant:

(a) The organization represents the interests of a broad group or class of customers and its participation in the proceeding will be primarily directed at public utility rates and terms and conditions of service affecting that broad group or class of customers, and not narrow interests or issues that are ancillary to the impact of the rates and terms and conditions of service to the customer group;

(b) The organization demonstrates that it is able to effectively represent the particular class of customers it seeks to represent;

(c) The organization's members who are customers of one or more of the utilities affected by the proceeding that are parties to the agreement contribute a significant percentage of the overall support and funding of the organization;

(d) The organization demonstrates, or has demonstrated in past Commission proceedings, the ability to substantively contribute to the record on behalf of customer interests related to rates and the terms and conditions of service, including in any proceeding in which the organization was case-certified and received a grant;

(e) The organization demonstrates that:

(A) No precertified intervenor participating in the proceeding adequately represents the specific interests of the class of customers represented by the organization related to rates and terms and conditions of service; or

(B) The specific interests of a class of customers will benefit from the organization's participation; and

(f) The organization demonstrates that its request for case-certification will not unduly delay the schedule of the proceeding.

Tab T

Or. Admin. R. 860-012-0190 Termination of Eligibility – Decertification

(1) Termination of Eligibility. Upon the filing of a complaint pursuant to ORS 756.500 or upon a Commission investigation or motion pursuant to ORS 756.515, the Commission may terminate the precertification or case-certification of an intervenor if it finds that:

(a) The organization has committed fraud, misrepresentation, or misappropriation related to any grant made available under the terms of a Commission-approved agreement;

(b) In a proceeding before the Commission for which grants were awarded to the organization, the organization has failed to represent the interests of the broad class of customers that the organization purported to represent in its application for precertification;

(c) The organization has failed to comply with Commission orders or rules in a material way;

(d)The intervenor who is signatory to an agreement has violated terms and conditions of the agreement pertaining to the use and disclosure of information required to be provided by utilities under the agreement;

(e) For the Citizens' Utility Board of Oregon (CUB), there has been a substantial change in or repeal of ORS 774.101 through 774.990; or

(f) A precertified organization other than CUB no longer meets the criteria of OAR 860-012-0100(3).

(2) An intervenor that is decertified under paragraph (1)(d) will be ineligible for future precertification or case-certification under the agreement.

(3) Termination of the precertification or case-certification of an intervenor shall be prospective only.

Tab U

Exhibit 3

Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts

Robert S. Harris and Felicia C. Marston

Robert S. Harris is the C. Stewart Sheppard Professor of Business at the Darden Graduate School of Business at the University of Virginia, Charlottesville, Virginia. Felicia C. Marston is an Assistant Professor of Commerce at the McIntire School of Commerce, University of Virginia, Charlottesville, Virginia.

■ One of the most widely used concepts in finance is that shareholders require a risk premium over bond yields to bear the additional risks of equity investments. While models such as the two-parameter capital asset pricing model (CAPM) or arbitrage pricing theory offer explicit methods for varying risk premia across securities, the models are invariably linked to some underlying market (or factor-specific) risk premium. Unfortunately, the theoretical models provide limited practical advice on establishing empirical estimates of such a benchmark market risk premium. As a result, the typical advice to practitioners is to estimate the market risk premium based on historical realizations of share and bond returns (see Brealey and Myers [3]).

In this paper, we present estimates of shareholder required rates of return and risk premia which are derived using forward-looking analysts' growth forecasts. We update, through 1991, earlier work which, due to data availability, was restricted to the period 1982-1984 (Harris [12]). Using stronger tests, we also reexamine the efficacy of using such an expectational approach as an alternative to the use of historical averages. Using the S&P 500 as a proxy for the market portfolio, we find an average market risk premium (1982-1991) of 6.47% above yields on long-term U.S. government bonds and 5.13% above yields on corporate bonds. We also find that required returns for individual stocks vary directly with their risk (as proxied by beta) and that the market risk premium varies over time. In particular, the equity market premium over government bond yields is higher in low interest rate environments and when there is a larger spread between corporate and government bond yields. These findings show that, in addition to fitting the theoretical requirement of being forward-looking, the utilization of analysts' forecasts in estimating return requirements provides reasonable empirical results that can be useful in practical applications.

Section I provides background on the estimation of equity required returns and a brief discussion of related

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literature on financial analysts' forecasts (FAF). In Section II, models and data are discussed. Following a comparison of the results to historical risk premia, the estimates are subjected to economic tests of both their time-series and cross-sectional characteristics in Section III. Finally, conclusions are offered in Section IV.

I. Background and Literature Review

In establishing economic criteria for resource allocation, it is often convenient to use the notion of a shareholder's required rate of return. Such a rate (k) is the minimum level of expected return necessary to compensate the investor for bearing risks and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds or other equities) and the riskiness of the stock. To isolate the effects of risk, it is useful to work in terms of a risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.[1]

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a benchmark "market" risk premium which then may be adjusted for the relative risk of individual stocks (e.g., using the CAPM or a variant). The historical studies of Ibbotson Associates [13] have been used frequently to implement this approach.[2] This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that risk premia are constant over time. Carleton and Lakonishok [5] demonstrate empirically some of the problems with such historical premia when they are disaggregated for different time periods or groups of firms.

As an alternative to historical estimates, the current paper derives estimates of k, and hence, implied values of rp, using publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow or DCF model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier works by Malkiel [17], Brigham, Vinson, and Shome [4], and Harris [12] have used FAF in DCF models, and this approach has been employed in regulatory settings (see Harris [12]) and suggested by consultants as an alternative to use of historical data (e.g., Ibbotson Associates [13, pp. 127, 128]). Unfortunately, the published studies use data extending to 1984 at the latest. Our paper draws on this earlier work but extends it through 1991.[3] Our work is closest to that done by Harris [12], who reviews literature showing a strong link between equity prices and FAF and supporting the use of FAF as a proxy for investor expectations. Using data from 1982 to 1984, Harris' results suggest that this expectational approach to estimating equity risk premia is an encouraging alternative to the use of historical averages. He also demonstrates that such risk premia vary both cross-sectionally with the riskiness of individual stocks and over time with financial market conditions.

II. Models and Data

A. Model for Estimation

The simplest and most commonly used version of the DCF model to estimate shareholders' required rate of return, k, is shown in Equation (2):

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share. The limitations of this model are well known, and it is straightforward to derive expressions for k based on more general specifications of the DCF model.[4] The primary difficulty in using the DCF model is obtaining an estimate of g, since it should reflect market expectations of future perfor-

[1]Theoretically, i is a risk-free rate, though empirically its proxy (e.g., yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk. In this development, the effects of tax codes on required returns are ignored.

[2]Many leading texts in financial management use such historical risk premia to estimate a market return. See, for example, Brealey and Myers [3]. Often a market risk premium is adjusted for the observed relative risk of a stock.

[3]See Harris [12] for a discussion of the earlier work and a detailed discussion of the approach employed here.

[4]As stated, Equation (2) requires expectations of either an infinite horizon of dividend growth at a rate g or a finite horizon of dividend growth at rate g and special assumptions about the price of the stock at the end of that horizon. Essentially, the assumption must ensure that the stock price grows at a compound rate of g over the finite horizon. One could alternatively estimate a nonconstant growth model, although the proxies for multistage growth rates are even more difficult to obtain than single stage growth estimates. Marston, Harris, and Crawford [19] examine publicly available data from 1982-1985 and find that plausible measures of risk are more closely related to expected returns derived from a constant growth model than to those derived from multistage growth models. These findings illustrate empirical difficulties in finding empirical proxies for multistage growth models for large samples.

mance. Without a ready source for measuring such expectations, application of the DCF model is fraught with difficulties. This paper uses published FAF of long-run growth in earnings as a proxy for g.

B. Data

FAF for this research come from IBES (Institutional Broker's Estimate System), which is a product of Lynch, Jones, and Ryan, a major brokerage firm.[5] Representative of industry practice, IBES contains estimates of (*i*) EPS for the upcoming fiscal years (up to five separate years), and (*ii*) a five-year growth rate in EPS. Each item is available at monthly intervals.

The mean value of individual analysts' forecasts of five-year growth rate in EPS will be used as a proxy for g in the DCF model.[6] The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base.

Dividend and other firm-specific information come from COMPUSTAT. Interest rates (both government and corporate) are gathered from Federal Reserve Bulletins and *Moody's Bond Record*. Exhibit 1 describes key variables used in the study. Data collected cover all dividend paying stocks in the Standard & Poor's 500 stock (S&P 500) index, plus approximately 100 additional stocks of regulated companies. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the 113-month period from January 1982 to May 1991.

III. Risk Premia and Required Rates of Return

A. Construction of Risk Premia

For each month, a "market" required rate of return is calculated using each dividend paying stock in the S&P 500 index for which data are available. The DCF model in

[5]Harris [12] provides a discussion of IBES data and its limitations. In more recent years, IBES has begun collecting forecasts for each of the next five years. Since this work was completed, the FAF used here have become available from IBES Inc., now a subsidiary of CitiBank.

[6]While the model calls for expected growth in dividends, no source of data on such projections is readily available. In addition, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same.

Exhibit 1. Variable Definitions

k	=	Equity required rate of return.
P_0	=	Average daily price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.[a]
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i_g	=	Yield to maturity on long-term U.S. government obligations (source: Federal Reserve Bulletin, constant maturity series).
i_c	=	Yield to maturity on long-term corporate bonds: Moody's average.[b]
rp	=	Equity risk premium calculated as $rp = k - i$.
β	=	beta, calculated from CRSP monthly data over 60 months.

Notes:
[a]See footnote 7 for a discussion of the $(1 + g)$ adjustment.
[b]The average corporate bond yield across bond rating categories as reported by Moody's. See *Moody's Bond Survey* for a brief description and the latest published list of bonds included in the bond rating categories.

Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market required return.[7] The return is converted to a risk premium

[7]The construction of D_1 is controversial since dividends are paid quarterly and may be expected to change during the year; whereas, Equation (2), as is typical, is being applied to annual data. Both the quarterly payment of dividends (due to investors' reinvestment income before year's end, see Linke and Zumwalt [15]) and any growth during the year require an upward adjustment of the current annual rate of dividends to construct D_1. If quarterly dividends grow at a constant rate, both factors could be accommodated straightforwardly by applying Equation (2) to quarterly data with a quarterly growth rate and then annualizing the estimated quarterly required return. Unfortunately, with lumpy changes in dividends, the precise nature of the adjustment depends on both an individual company's pattern of growth during the calendar year and an individual company's required return (and hence reinvestment income in the risk class).
In this work, D_1 is calculated as $D_0(1 + g)$. The full g adjustment is a crude approximation to adjust for both growth and reinvestment income. For example, if one expected dividends to have been raised, on average, six months ago, a "1/2 g" adjustment would allow for growth, and the remaining "1/2 g" would be justified on the basis of reinvestment income. Any precise accounting for both reinvestment income and growth would require tracking each company's dividend change history and making explicit judgments about the quarter of the next change. Since no organized "market" forecast of such a detailed nature exists, such a procedure is not possible. To get a feel for the magnitudes involved, during the sample period the dividend yield (D_1/P_0) and growth (market value weighted) for the S&P 500 were typically 4% to 6% and 11% to 13%, respectively. As a result, a "full g" adjustment on average increases the required return by 60 to 70 basis points (relative to no g adjustment).

Exhibit 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium,[a] 1982-1991

	Bond Market Yields[b]		Equity Market Required Return[c]	Equity Risk Premium	
Year	(1) U.S. Gov't	(2) Moody's Corporates	(3) S&P 500	U.S. Gov't (3) - (1)	Moody's Corporates (3) - (2)
1982	12.92	14.94	20.08	7.16	5.14
1983	11.34	12.78	17.89	6.55	5.11
1984	12.48	13.49	17.26	4.78	3.77
1985	10.97	12.05	16.32	5.37	4.28
1986	7.85	9.71	15.09	7.24	5.38
1987	8.58	9.84	14.71	6.13	4.86
1988	8.96	10.18	15.37	6.41	5.19
1989	8.46	9.66	15.06	6.60	5.40
1990	8.61	9.77	15.69	7.08	5.92
1991[d]	8.21	9.41	15.61	7.40	6.20
Average[e]	9.84	11.18	16.31	6.47	5.13

Notes:
[a]Values are averages of monthly figures in percent.
[b]Yields to maturity.
[c]Required return on value weighted S&P 500 index using Equation (1).
[d]Figures for 1991 are through May.
[e]Months weighted equally.

over government bonds by subtracting i_g, the yield to maturity on long-term government bonds. A risk premium over corporate bond yields is also constructed by subtracting i_c, the yield on long-term corporate bonds. Exhibit 2 reports the results by year (averages of monthly data).

The results are quite consistent with the patterns reported earlier (i.e., Harris [12]). The estimated risk premia in Exhibit 2 are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1991) over government bonds is 6.47%, only slightly higher than the 6.16% average for 1982 to 1984 reported earlier (Harris [12]). Furthermore, Exhibit 2 shows the estimated risk premia change over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities.

For comparison purposes, Exhibit 3 contains historical returns and risk premia. The average expectational risk premium reported in Exhibit 2 falls roughly midway between the arithmetic (7.5%) and geometric (5.7%) long-term differentials between returns on stocks and long-term government bonds. Note, however, that the expectational risk premia appear to change over time. In the following sections, we examine the estimated risk premia to see if they vary cross-sectionally with the risk of individual stocks and over time with financial market conditions.

B. Cross-Sectional Tests

Earlier, Harris [12] conducted crude tests of whether expectational equity risk premia varied with risk proxied by bond ratings and the dispersion of analysts' forecasts and found that required returns increased with higher risk. Here we examine the link between these premia and beta, perhaps the most commonly used measure of risk for equities.[8] In keeping with traditional work in this area, we adopt the methodology introduced by Fama and Macbeth [9] but replace realized returns with expected returns from Equation (2) as the variable to be explained. For this portion of our tests, we restrict our sample to 1982-1987

[8]For other efforts using expectational data in the context of the two-parameter CAPM, see Friend, Westerfield, and Granito [10], Cragg and Malkiel [7], Marston, Crawford, and Harris [19], Marston and Harris [20], and Linke, Kannan, Whitford, and Zumwalt [16]. For a more complete treatment of the subject, see Marston and Harris [20] from which we draw some of these results. Marston and Harris also investigate the role of unsystematic risk and the difference in estimates found when using expected versus realized returns.

Exhibit 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the U.S., 1926-1989

Historical Return Realizations	Geometric	Arithmetic
Common stock	10.3%	12.4%
Long-term government bonds	4.6%	4.9%
Long-term corporate bonds	5.2%	5.5%
Treasury bills	3.6%	3.7%
Inflation rate	3.1%	3.2%

Source: Ibbotson Associates, Inc., *1990 Stocks, Bonds, Bills and Inflation*, 1990 Yearbook.

and in any month include firms that have at least three forecasts of earnings growth to reduce measurement error associated with individual forecasts.[9] This restricted sample still consists of, on average, 399 firms for each of the 72 months (or 28,744 company months).

For a given company in a given month, beta is estimated via the market model (using ordinary least squares) on the prior 60 months of return data taken from CRSP. Beta estimates are updated monthly and are calculated against an equally weighted index of all NYSE securities. For each month, we aggregate firms into 20 portfolios (consisting of approximately 20 securities each). The advantage of grouped data is the reduction in potential measurement error inherent in independent variables at the company level. Portfolios are formed based on a ranking of beta estimated from a prior time period (t = -61 to t = -120). Portfolio expected returns and beta are calculated as the simple averages for the individual securities.

Using these data, we estimate the following model for each of the 72 months:

$$R_p = \alpha_0 + \alpha_1 \beta_p + u_p, \quad p = 1...20, \qquad (3)$$

where:

R_p = Expected return for portfolio p in the given month,

β_p = Portfolio beta, estimated over 60 prior months, and

u_p = A random error term with mean zero.

As a result of estimating regression (3) for each month, 72 estimates of each coefficient (α_0 and α_1) are obtained. Using realized returns as the dependent variable, the traditional approach (e.g., Fama and Macbeth [9]) is to assume that realized returns are a fair game. Given this assumption, the mean of the 72 values of each coefficient is an unbiased estimate of the mean over that same time period if one could have actually used expected returns as the dependent variable. Note that if expected returns are used as the dependent variable the fair-game assumption is not required. Making the additional assumption that the true value of the coefficient is constant over the 72 months, a test of whether the mean coefficient is different from zero is performed using a t-statistic where the denominator is the standard error of the 72 values of the coefficient. This is the technique employed by Fama and Macbeth [9]. If one assumes the CAPM is correct, the coefficient α_1 is an empirical estimate of the market risk premium, which should be positive.

To test the sensitivity of the results, we also repeat our procedures using individual security returns rather than portfolios. To account, at least in part, for differences in precision of coefficient estimates in different months we also report results in which monthly parameter estimates are weighted inversely by the standard error of the coefficient estimate rather than being weighted equally (following Chan, Hamao, and Lakonishok [6]).

Exhibit 4 shows that there is a significant positive link between expectational required returns and beta. For instance, in Panel A, the mean coefficient of 2.78 on beta is significantly different from zero at better than the 0.001 level (t = 35.31), and each of the 72 monthly coefficients going into this average is positive (as shown by that 100% positive figure). Using individual stock returns, the significant positive link between beta and expected return remains, though it is smaller in magnitude than for portfolios.[10] Comparison of Panels A and B shows that the results are not sensitive to the weighting of monthly coefficients.

While the findings in Exhibit 4 suggest a strong positive link between beta and risk premia (a result often not supported when realized returns are used as a proxy for expectations; e.g., see Tinic and West [22]), the results do not support the predictions of a simple CAPM. In particular, the intercept is higher than a proxy for the risk-free rate over the sample period and the coefficient of beta is well below estimates of a market risk premium obtained from either expectational (Exhibit 2) or historical data (Exhibit

[9]Firms for which the standard deviation of individual FAF exceeded 20 in any month were excluded since we suspect some of these involve errors in data entry. This screen eliminated very few companies in any month. The 1982-1987 period was chosen due to the availability of data on betas.

[10]The smaller coefficients on beta using individual stock portfolio returns are likely due in part to the higher measurement error in measuring individual stock versus portfolio betas.

Exhibit 4. Mean Values of Monthly Parameter Estimates for the Relationship Between Required Returns and Beta for Both Portfolios and Individual Securities (Figures in Parentheses are *t* Values and Percent Positive), 1982-1987

	Intercept	β	Adjusted R^2 [c]	F [c]
Panel A. Equal Weighting [a]				
Portfolio returns	14.06 (54.02, 100)	2.78 (35.31, 100)	0.503	25.4
Security returns	14.77 (58.10, 100)	1.91 (16.50, 99)	0.080	39.0
Panel B. Weighted by Standard Errors [b]				
Portfolio returns	13.86 (215.6, 100)	2.67 (35.80, 100)	0.503	25.4
Security returns	14.63 (398.9, 100)	1.92 (47.3, 99)	0.080	39.0

[a] Equally weighted average of monthly parameters estimated using cross-sectional data for each of the 72 months, January 1982 - December 1987.
[b] In obtaining the reported means, estimates of the monthly intercept and slope coefficients are weighted inversely by the standard error of the estimate from the cross-sectional regression for that month.
[c] Values are averages for the 72 monthly regressions.

3).[11] Nonetheless, the results show that the estimated risk premia conform to the general theoretical relationship between risk and required return that is expected when investors are risk-averse.

C. Time Series Tests — Changes in Market Risk Premia

A potential benefit of using ex ante risk premia is the estimation of changes in market risk premia over time. With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk. For example, during the high interest rate period of the early 1980s, the high level of interest rate volatility made fixed income investments more risky holdings than they were in a world of relatively stable rates.

Studying changes in risk premia for utility stocks, Brigham, et al [4] conclude that, prior to 1980, utility risk premia increased with the level of interest rates, but that this pattern reversed thereafter, resulting in an inverse correlation between risk premia and interest rates. Studying risk premia for both utilities and the equity market generally, Harris [12] also reports that risk premia appear to change over time. Specifically, he finds that equity risk premia decreased with the level of government interest rates, increased with the increases in the spread between corporate and government bond yields, and increased with increases in the dispersion of analysts' forecasts. Harris' study is, however, restricted to the 36-month period, 1982 to 1984.

Exhibit 5 reports results of analyzing the relationship between equity risk premia, interest rates, and yield spreads between corporate and government bonds. Following Harris [12], these bond yield spreads are used as a time series proxy for equity risk. As the perceived riskiness of corporate activity increases, the difference between yields on corporate bonds and government bonds should increase. One would expect the sources of increased riskiness to corporate bonds to also increase risks to shareholders. All regressions in Exhibit 5 are corrected for serial correlation.[12]

[11] Estimation difficulties confound precise interpretation of the intercept as the risk-free rate and the coefficient on beta as the market risk premium (see Miller and Scholes [21], and Black, Jensen, and Scholes [2]). The higher than expected intercept and lower than expected slope coefficient on beta are consistent with the prior studies of Black, Jensen, and Scholes [2], and Fama and MacBeth [9] using historical returns. Such results are consistent with Black's [1] zero beta model, although alternative explanations for these findings exist as well (as noted by Black, Jensen, and Scholes [2]).

[12] Ordinary least squares regressions showed severe positive autocorrelation in many cases, with Durbin Watson statistics typically below one. Estimation used the Prais-Winsten method. See Johnston [14, pp. 321-325].

Exhibit 5. Changes in Equity Risk Premia Over Time — Entries are Coefficient (t-value); Dependent Variable is Equity Risk Premium

Time period	Intercept	i_b	$i_c - i_b$	R^2
A. May 1991-1992	0.131 (19.82)	-0.651 (-11.16)		0.53
	0.092 (14.26)	-0.363 (-6.74)	0.666 (5.48)	0.54
B. 1982-1984	0.140 (8.15)	-0.637 (-5.00)		0.43
	0.064 (3.25)	-0.203 (-1.63)	1.549 (4.84)	0.60
C. 1985-1987	0.131 (7.73)	-0.739 (-9.67)		0.74
	0.110 (12.53)	-0.561 (-7.30)	0.317 (1.87)	0.77
D. 1988-1991	0.136 (16.23)	-0.793 (-8.29)		0.68
	0.130 (8.71)	-0.738 (-4.96)	0.098 (0.40)	0.68

Note: All variables are defined in Exhibit 1. Regressions were estimated using monthly data and were corrected for serial correlation using the Prais-Winsten method. For purposes of this regression, variables are expressed in decimal form, e.g., 14% = 0.14.

For the entire sample period, Panel A shows that risk premia are negatively related to the level of interest rates — as proxied by yields on government bonds, i_b. This negative relationship is also true for each of the subperiods displayed in Panels B through D. Such a negative relationship may result from increases in the perceived riskiness of investment in government debt at high levels of interest rates. A direct measure of uncertainty about investments in government bonds would be necessary to test this hypothesis directly.

For the entire 1982 to 1991 period, the addition of the yield spread risk proxy to the regressions dramatically lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 2 of Panel A. Furthermore, the coefficient of the yield spread (0.666) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate activity is translated into a lower equity market risk premium. Further examination of Panels B through D, however, suggests that the yield spread variable is much more important in explaining changes in equity risk premia in the early portion of the 1980s than in the 1988 to 1991 period.

In summary, market equity risk premia change over time and appear inversely related to the level of government interest rates but positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds.

IV. Conclusions

Shareholder required rates of return and risk premia are based on theories about investors' expectations for the future. In practice, however, risk premia are often estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. At least for the decade studied (1982 to 1991), the resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1989) in historical returns between stocks and bonds. There is strong evidence, however, that market risk premia change over time and, as a result, use of a constant historical average risk premium is not likely to mirror changes in investor return requirements. The results also show that the expectational risk premia vary cross-sectionally with the relative risk (beta) of individual stocks.

The approach offers a straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena. Since data are readily available on a wide range of equities, an investigator can analyze various proxy groups (e.g., portfolios of utility stocks) appropriate for a particular decision as well as analyze changes in equity return requirements over time.

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Tab V

Exhibit 4

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Risk and Return: A Revisit Using Expected Returns

Felicia Marston and Robert S. Harris**

Abstract

This paper uses direct estimates of expected returns to examine the link between standard measures of financial risk and investor return requirements. The results show that systematic risk commands a significant positive risk premium, much larger than found using historical returns as proxies for expectations. Furthermore, there are nonlinearities in the relationship between risk and return. Finally, we show that expected returns and risk premiums in the equity markets change over time and that these changes are related to changes in interest rates on U.S. government obligations.

Introduction

While theories of asset pricing are based on investor expectations, almost all empirical investigations employ returns actually realized over some historical period. Use of realizations has been the child of necessity since data on expectations have generally not been available. In this paper, we take advantage of financial analysts' forecasts to derive measures of expected return for over 400 stocks. The measures are updated monthly for the six-year period, 1982–1987.

These data are then used to test the link between investor expected returns and standard measures of financial risk. The results are compared to those obtained from the traditional method of using realized returns to proxy expectations, following the methodology of Fama and Macbeth [10] and Tinic and West [30]. The results thus provide further evidence on how empirical results

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are affected by choice of the proxy for expected returns. We also examine whether expected returns on stocks change over time and whether these changes are related to developments in the bond market.

The next section relates our approach to prior empirical work. Data and methodology are described in the following section. The next two sections present empirical results, and the paper ends with a summary and conclusions.

Realized Returns and Risk

Theory suggests that investors will demand extra return to compensate them for bearing incremental risk. Perhaps the most extensively used measures of risk in finance stem from portfolio theory and the two-parameter capital asset pricing model (CAPM). These risk measures distinguish between total and systematic (undiversifible) risk.

Empirical testing of the link between return and risk, however, has a long tradition of using realized returns. Such use requires the assumption that realized returns are a fair game, and hence, on average, realizations equal expectations (e.g., Fama and Macbeth [10] and Tinic and West [30]). While the assumption that realizations equal expectations may be true over long sweeps of history, it is not appropriate for most shorter time frames in a risky market. As a result, studies using realized returns require extremely long time periods and typically produce results that are quite sensitive to the subperiod studied. In early work using realized returns, Fama and Macbeth [10] conclude that expected returns increase with systematic risk, that the relationship between expected return and systematic risk is linear, and that nonsystematic risk is not related to returns. Even using Fama and Macbeth's methodology and extending it to more recent years, however, Tinic and West [30] could not support these three conclusions.

A primary obstacle for empirical work using expected, rather than realized, returns is obtaining a reasonable proxy for market expectations. Ang and Peterson [1] use Value Line projections of dividends and stock price to derive expected returns for use in tests of Brennan's [3] after-tax CAPM. Their work, however, relies on forecasts of a single analyst. In an effort to take advantage of larger and more comprehensive data sets on expectations, researchers have turned to financial analysts' forecasts of corporate earnings. Such forecasts are widely used by investors as evidenced by the commercial viability of services that provide such forecasts and by the results of studies of investors' behavior (Touche, Ross and Company [31] and Stanley, Lewellen, and Schlarbaum [28]). Moreover, research using consensus measures of earnings forecasts (typically a simple average of forecasts by individual analysts) demonstrates that such forecasts are incorporated in stock prices.[1]

Other research has translated earnings expectations into expected returns using the dividend growth model. Malkiel [21], Brigham, Shome, and Vinson [4], and Harris [16] derive risk premia for various market indices using this approach.[2] Friend, Westerfield, and Granito [12], Cragg and Malkiel [8], Linke, Kannan, Whitford, and Zumwalt [19], Marston [22], and Marston, Harris, and Crawford [23] use analysts' forecasts of long-term earnings growth in dividend valuation models to proxy expected returns. These returns are then related to measures of systematic and nonsystematic risk.[3]

Our work advances prior research by providing a direct examination of sensitivity of tests of the link between risk and return to use of earnings-based measures of expected return versus realized return. Unlike prior studies using forecast data, we use the traditional methodology of Fama-Macbeth [10] and apply it to both realized and expected returns. Such a procedure allows direct comparison to earlier work using the same methods on realized returns as well as a direct comparison of differences in results using expected returns as opposed to realized returns.[4]

Data and Methodology

Following prior research, we employ the dividend growth model to translate earnings forecasts into expected returns. Such use implicitly assumes that long-term growth in dividends is dependent on long-term growth in earnings. Estimates of expected return are calculated at monthly intervals using consensus financial analysts' forecasts (FAF) of five-year growth in earnings per share (g) in the dividend growth model:

$$\text{Expected Return} = \frac{Do(1 + g)}{Po} + g.$$

FAF are obtained from the Institutional Brokers' Estimate System (IBES). Each month, IBES provides mean estimates of earnings per share for the next year and up to four following years. In addition, IBES records analysts' projections of five-year growth rates in earnings per share. Mean values are calculated as the arithmetic average of forecasts by individual analysts.[5] Stock prices (Po) are obtained from Chase Econometrics, and the current indicated annual dividend (Do) is obtained from Compustat. Long-term (five-year) growth forecasts are only available after December 1981; thus, expected return measures are calculated for each of the 72 months from January 1982 through December 1987. Realized monthly returns (January 1982–December 1987) are obtained from the Center for Research in Security Prices (CRSP) for comparative purposes.

The sample is selected from firms in the Standard & Poor's (S&P) 500 Index and from a set of approximately 100 additional utility stocks followed by IBES. Given our use of the dividend growth model, the analysis is restricted to firms that pay dividends and have IBES forecasts of earnings growth. Additionally, to be included in the study, there must be at least three forecasts of earnings growth available for each stock. This latter screen is imposed to reduce measurement error associated with individual forecasts.[6] The final sample consists of approximately 400 firms for each of the seventy-two months (approximately 28,800 company months). Although our data do not allow analysis of the entire New York Stock Exchange (NYSE) as in Fama and Macbeth [10] and Tinic and West [30], our study is based on a large number of well-followed firms.

Following prior work, we examine the relationship of return to beta, beta squared, and residual (firm-specific) risk. To compare our results to earlier work, we replicate the methodology introduced by Fama and Macbeth [10] and used by Tinic and West [30].[7] For a given company in a given month, beta is estimated via the market model (using ordinary least squares) on the prior sixty months of data. Beta estimates are updated monthly and are calculated against both an equal- and value-weighted index of all NYSE securities. Firm-specific (nonsystematic) risk is proxied by the residual standard deviation from the regression used to estimate beta. While use of historical data to calculate risk measures implicitly assumes that such measures are stable over the estimation period, this stability assumption is much weaker than assuming expected returns are equal to realized returns. Furthermore, such risk estimates (e.g., beta) from historical data are widely used by investors and thus represent a risk proxy that investors may have available in pricing assets.

For each month, we aggregate firms into twenty portfolios (consisting of approximately twenty securities each). The advantage of grouped data is the reduction in potential measurement error inherent in independent variables at the company level. Portfolios are formed based on a ranking of beta estimated from a prior time period ($t = -61$ to $t = -120$). Portfolio expected (and realized) returns, beta, beta squared, and residual risk measures are calculated as the simple averages for the individual securities. (Descriptive statistics are provided in Table 1.)

Using these data, we estimate the following model for each of the seventy-two months:

$$R_{pt} = a_{0t} + a_{1t}\beta_{pt-1} + a_{2t}\beta^{2}_{pt-1} + a_{3t}S(e_{pt-1}) + U_{pt},\ p = 1 \ldots 20, \quad (1)$$

where

R_{pt} = expected return for portfolio p in month t,
β_{pt-1} = portfolio beta, estimated over $t - 60$ to $t - 1$,
β^{2}_{pt-1} = portfolio beta squared,
$S(e_{pt-1})$ = portfolio residual risk, and
U_{pt} = a random error term with mean zero.

The model is then reestimated substituting monthly realized returns for expected returns. To replicate Tinic

TABLE 1

Sample Statistics: 1982–1987

For each of the 72 months (1982–1987), the sample companies are grouped into 20 portfolios. For each portfolio, an equally weighted average of characteristics is calculated. Means and standard deviations in the table are based on these 1440 portfolios (20 portfolios for each of 72 months).

Variable	Mean	Standard Deviation
Expected return	0.1635	0.0205
Historical return (annualized)	0.2007	0.2218
Long-Term Treasury note (yield)	0.1069	0.0206
One-month T-bill (annualized yield)	0.0780	0.0059
Beta (equal-weighted index)	0.8222	0.2511
Beta (value-weighted index)	0.9339	0.2552
Beta squared (equal-weighted index)	0.7930	0.4243
Beta squared (value-weighted index)	0.9373	0.4599
Residual risk (based on equal-weighted β)	0.0647	0.0090
Residual risk (based on value-weighted β)	0.0644	0.0094
Number of analysts	10.12	1.86

and West [30], we use return as the dependent variable rather than a risk premium formed by subtracting the risk-free rate. This procedure also allows us to avoid, at least initially, specifying the appropriate maturity for calculation of a risk-free proxy.

As a result of estimating regression (1) for each month, seventy-two estimates of each coefficient are obtained. Using realized returns as the dependent variable, the traditional approach (Fama and Macbeth [10], Tinic and West [30]) is to assume that realized returns are a fair game. Given this assumption, the mean of the seventy-two values of each coefficient is an unbiased estimate of the mean coefficient over that same time period if one could have actually used expected returns as the dependent variable. Note that if expected returns are used as the dependent variable the fair-game assumption is not required. Making the additional assumption that the true value of the coefficient is constant over the seventy-two months, a test of whether the mean coefficient is different from zero is performed using a t-statistic where the denominator is the standard error of the seventy-two values of the coefficient. This is the technique employed by Fama and Macbeth [10] and followed by Tinic and West [30].

If the traditional version of the CAPM were to hold, the intercept a_0 (equation (1)) should be equal to the risk-free rate of return. The coefficient of beta (a_1) is an estimate of the market risk premium, which should be positive. Unsystematic risk should not be priced (a_3 = 0), and there should be a linear relationship between return and systematic risk (a_2 = 0). In addition to examining estimates of these parameters, we examine whether the expected returns and risk premiums vary over time.

Empirical Results

Table 1 presents summary statistics for the sample companies. For the six-year period, expected returns average 16.35 percent, well above yields on government bonds. For the same period, realized returns are even higher, exceeding 20 percent on an annual basis. As a result, the time period studied is not subject to the criticism that realized returns are negative (or less than bond yields), violating most reasonable economic restrictions on a proxy for investor expectations. The high realized returns reflect the strong bull market during the period. In our sample, expected returns appear to demonstrate quite different patterns from realized returns. Although not shown in Table 1, the correlation between ex ante and ex post returns (using averages for the seventy-two-month period) for the twenty portfolios is only 0.0622 over the sample period and is insignificantly different from zero. As a result, use of expected returns may well reveal new information about the pricing of risk in markets.

The sample companies have somewhat lower systematic risk (β) than does the market generally (β = 1.0). This is due to the sample selection, which uses only dividend-paying stocks followed by analysts. Such stocks are less risky than stocks generally. Table 1 also shows that β measures are generally increased by going from an equally weighted index to a value-weighted index as a market proxy.

Table 2 reports Tinic and West's [30] results (panel A) and updates their work (1982–1987) using both realized returns (panel B) and expected returns (panel C). Panels A and B use monthly realized returns while panel C uses expected returns (annualized rates) on a monthly basis.

Realized Returns

Panel B shows that in the 1982–1987 period, systematic risk is not related to realized return: the estimate of a_1 is 0.0056, which is not significantly different from zero (t = 0.21). Both the intercept (0.0300) and coefficient of residual risk (−0.3228) are significant at the 0.10 level; however, there is an insignificant coefficient on beta squared.

Comparison of panels A and B shows that the 1982–1987 time period does not conform to the results for the longer period (1935–1982) studied by Tinic and West [30]. This is consistent with Tinic and West's [30] finding of significant differences among subperiods. For instance, as shown in panel A of Table 2, Tinic and West [30] find that beta is not significantly related to return in the post-1959 period.

In summary, both Tinic and West's [30] results for the last half of their study and our results (1982–1987) with realized returns provide no support for a positive link between return and systematic risk as suggested by the CAPM. The generally insignificant coefficients undoubtedly reflect the difficulties of using realized returns to test an *ex ante* model, especially for short time intervals.

Expected Returns

Use of expected returns in panel C produces quite different results. Expected returns are strongly positively related to beta: the average value of a_1 is 0.0522, which is significantly different from zero (t = 5.78). There is some evidence of nonlinearity given the negative value of a_2, although the coefficient is not significantly different from zero (t = − 1.44). The significant negative value of a_3 suggests that higher unsystematic risk actually reduces expected return. We suspect that a_3 may be proxying in part for any nonlinearity in the relationship between beta and return, as discussed sub-

TABLE 2

Average Values of the Estimated Coefficients of the Four-Parameter Model

$R_{pt} = a_{0t} + a_{1t}\beta_{pt-1} + a_{2t}\beta^2_{pt-1} + a_{3t}S(e_{pt-1}) + U_{pt}$

Regressions are estimated with monthly data and based on an equally weighted market index. t-statistics are in parentheses and are estimated as the mean value for the monthly coefficient values divided by the standard error of these monthly values. An asterisk (*) indicates significance at the 0.05 level (two-tailed test).

	Number of Months	a_0	a_1	a_2	a_3
A. Tinic and West					
1. Jan 35–Dec 82	576	−0.0004 (−0.10)	0.0134* (2.02)	−0.0048 (−1.52)	0.0807 (1.90)
2. Jan 35–Dec 58	288	0.0004 (0.09)	0.0213* (2.80)	−0.0078* (−2.07)	0.0318 (0.57)
3. Jan 59–Dec 82	288	−0.0012 (−0.20)	0.0055 (0.50)	−0.0021 (−0.40)	0.1296* (2.01)
4. Jan 69–Dec 82	168	0.0008 (0.09)	0.0026 (0.16)	−0.0010 (−0.13)	0.0866 (0.97)
B. Update of Tinic and West Jan 82–Dec 87	72	0.0300 (1.94)	0.0056 (0.21)	0.0034 (0.22)	−0.3228 (−1.94)
C. Estimation with Expected Returns Jan 82–Dec 87	72	0.1506* (27.1)	0.0522* (5.78)	−0.0078 (−1.44)	−0.3593* (−6.74)

sequently. Economically speaking, however, the effects of these last two variables appear quite small. For example, using the summary statistics in Table 1, a one standard deviation change in either beta squared or residual risk would change expected returns by less than one-third of one percent.[8] As a result, the results in panel C are roughly consistent with a two-parameter CAPM for the 1982–1987 period even though there is some evidence of nonlinearity in the data.

According to the CAPM, the intercept, a_0, in regression (1) should be equal to the risk-free rate. We calculated the difference between a_0 (estimated from expected returns) and a proxy for the risk-free rate in each of the seventy-two months. A t-statistic was then constructed as the mean difference divided by the standard error of the differences. Using both Treasury bill yields and long-term Treasury bond yields as proxies for the risk-free rate, we obtained the following results (all rates annualized):

Proxy for Risk-Free Rate	Mean Difference	t-value
Treasury bill	0.0687	16.06
Treasury bond	0.0437	10.58

The results show that a_0 is substantially above the risk-free rate. This difference may reflect at least one additional factor, not captured by beta, beta squared, or residual risk, that is priced in the market.

Value-Weighted versus Equally Weighted Market Index

Motivated by the potential impact of changes in the composition of the market portfolio, Tinic and West [30] replicate all their tests using a value-weighted CRSP index. The results do not change their conclusion that the CAPM is not well supported by the data. We also test for the importance of the market proxy as shown in panel A of Table 3.

Using historical returns, panel A shows no support for the CAPM when a value-weighted index is used, consistent with Tinic and West's [30] observation. The results for expected returns using value-weighted results make a much stronger case for nonlinearity in the risk return tradeoff given the significant negative value of a_2. Furthermore, the reduced significance of a_3 in going to value-weighted results (at the same time a_2 changes) suggests both beta squared and residual risk may proxy for some underlying nonlinearity in the effects of beta on expected return.[9] The economic significance of beta squared is still relatively small, as a one standard deviation change in beta squared changes expected returns by approximately one percent. Our tests with expected returns thus show beta is positively related to return but that risk premiums do not increase linearly with beta as predicted by the CAPM; rather, risk premiums increase less than proportionally with increases in beta.

Individual Securities versus Portfolio Returns

While theories such as the CAPM make predictions about individual assets, empirical tests typically employ portfolios in an attempt to reduce measurement error in estimating risk. Unfortunately, such portfolio formation may mask important risk-return relationships that are relevant for individual securities. To test for the sensitivity of our results to portfolio formation, we repeated the analysis using return and risk measures for each of the approximately 400 individual stocks. Panel B of Table 3 shows the results. As was true for portfolios, the results using historical returns for individual securities provide no support for the CAPM using either an equal- or value-weighted market index. The insignificant coefficients are typical of results using monthly historical returns over short (seventy-two months) time spans.

Turning to the results for expected returns, we see that individual securities show much the same patterns as did portfolios. There is a significant positive relationship between systematic risk (beta) and expected returns, as predicted by the CAPM; however, the significant negative coefficients, a_2 and a_3, show that further predictions of the CAPM are not validated.[10]

Changes in Expected Returns and Risk Premiums

One-period models such as the CAPM make no requirement that expected returns or risk premiums are constant over time. In recent years, empirical research

TABLE 3

Average Values of the Estimated Coefficients of the Four-Parameter Model: Sensitivity to Market Index and Portfolio Formation

$$R_t = a_{0t} + a_{1t}\beta_{t-1} + a_{2t}\beta^2_{t-1} + a_{3t}S(e_{i,t}) + U_t$$

Regressions are estimated with monthly data. t-statistics are in parentheses and are estimated as the mean value for the monthly coefficient values divided by the standard error of these monthly values. An asterisk (*) indicates significance at the 0.05 level (two-tailed test).

	a_0	a_1	a_2	a_3
A. Portfolio Returns (1982–1987)				
1. Historical Returns				
Equal-Weighted Index	0.0300	0.0056	0.0034	−0.3228
	(1.94)	(0.21)	(0.22)	(−1.94)
Value-Weighted Index	0.0162	0.0157	−0.0062	−0.1523
	(1.17)	(0.63)	(−0.51)	(−0.90)
2. Expected Returns				
Equal-Weighted Index	0.1506*	0.0522*	−0.0078	−0.3593*
	(27.10)	(5.78)	(−1.44)	(−6.74)

Value-Weighted Index	0.1198*	0.0788*	−0.0255*	−0.0943*
	(20.83)	(8.25)	(−5.16)	(−2.04)
B. Individual-Security Returns (1982–1987)				
1. Historical Returns				
Equal-Weighted Index	0.0196*	0.0061	−0.0041	−0.0860
	(2.48)	(0.43)	(−0.75)	(−1.27)
Value-Weighted Index	0.0144	0.0062	−0.0056	−0.0242
	(1.73)	(0.48)	(−1.24)	(0.38)
2. Expected Returns				
Equal-Weighted Index	0.1405*	0.0628*	−0.0217*	−0.1635*
	(45.78)	(33.58)	(−23.98)	(−9.83)
Value-Weighted Index	0.1392*	0.0549*	−0.0167*	−0.1445*
	(37.50)	(23.50)	(−19.30)	(−12.80)

has begun to recognize that expected returns do vary through time. There is substantial evidence that expected returns on both stocks and bonds vary based on significant autocorrelations of returns and significant coefficients when returns are regressed on various predetermined variables (see Kandel and Stambaugh [17]). Furthermore, some research has incorporated the possibility for such time variation in tests of asset pricing models (e.g., Gibbons and Ferson [14] and Ferson, Kandel, and Stambaugh [11]). To date, these approaches have generally, however, tried to infer expectations from realizations. As a result, expectations are modeled as weighted averages of past data (Conrad and Kaul [6]) or via some relatively *ad hoc* regression of realized returns on predetermined variables such as term premiums in the bond market or month of the year. In these cases, great care must be taken to ensure that the inferred expectations are not simply "fits" of data that bear little if any relationship to expectations themselves. In the subsequent discussion, we analyze changes in expected returns and risk premiums over time. By using our proxies for expected returns, rather than realized returns, we are able to provide further insights into changes in expectations over time.

Expected returns will increase with the risk-free rate unless market risk premiums decrease in an offsetting fashion. To examine these changes, we regress the seventy-two monthly sample averages of return on both short- and long-term interest rates as proxies for the risk-free rate. If the equity market risk premium were constant over time, we would expect a slope coefficient of unity and an intercept equal to the risk premium.

Table 4 shows that expected returns increase with bond yields. For the seventy-two-month period, the second regression in Table 4 shows that variations in long-term Treasury bond yields explain 38 percent of the time series variation in expected returns. The results also suggest that the market risk premium itself is not constant over time. The slope coefficient of 0.4550 is significantly less than unity (t = 7.79), suggesting that expected returns do not increase one-for-one with interest rates. For example, the 0.4550 coefficient implies that a

TABLE 4

Relationship of Expected Returns and Interest Rates

Entries are estimated coefficient and t-value (in parentheses). Time series regressions are estimated on the 72 monthly observations. Expected return is the mean return for the sample in that month. All yields have been annualized. Regressions were estimated using the Prais-Winsten method to correct for serial correlation. An asterisk (*) indicates significance at the 0.05 level (two-tailed test).

Dependent Variable	Intercept	Yield on Treasury Bill	Yield on Treasury Bond	R^2
1. Expected Return	0.1309* (24.97)	0.4248* (6.70)		0.39
2. Expected Return	0.1160* (14.15)		0.4550* (6.50)	0.38

1.0 percent increase in bond yields is accompanied by a 0.4550 percent increase in expected return on the equity market. This implies a 0.5450 percent (1 − 0.4550 = 0.5450) drop in the market risk premium calculated as the spread between expected returns on equities and bond yields.[11]

The results in Table 4 thus suggest that the market risk premium changes over time and that the changes are related to interest rates. Explanation of changes in expected returns requires further research incorporating variables hypothesized as being related to changes in risk premiums.

We repeated the analysis in Table 4 using realized returns rather than expected returns. In neither regression was the slope coefficient significantly different from zero at the 0.10 level and both R^2 values were less than 0.05. These weak findings demonstrate the difficulty in using changes in realized returns over any short interval to make inferences about changes in market expectations.

Summary and Conclusions

Employing direct estimates of expected returns constructed from financial analysts' forecasts, we show that systematic risk commands a significant positive risk premium, much larger than found using historical data as a proxy for expectations. We also show that there are nonlinearities in the tradeoff between expected return and systematic risk. The nonlinearities are, however, not large in terms of their economic impact on expected return. These conclusions are robust to use of different proxies for the market portfolio and use of individual company versus portfolio returns. We still find, however, that expected returns are higher than can be explained by yields on U.S. Treasury obligations plus risk premiums associated with beta and residual risk.

Our use of proxies for expected return also allow exploration of how such returns and resultant risk premiums change over time. We show that, as predicted, expected returns on equities increase with rates available in the bond market. Such increases are accompanied, however, by a reduction in the apparent difference between expected returns on equity and long-term interest rates. Explanation of such changes in risk premiums over time requires additional research.

Notes

1. Elton, Gruber, and Gultekin [9] show that stock prices react more to changes in analysts' forecasts than they do to changes in earnings themselves. Cragg and Malkiel [8] conclude "the expectations formed by Wall Street professionals get quickly and thoroughly impounded into the prices of securities" (p. 165). Givoly and Lakonishok [15] survey research on analysts' earnings forecasts. They conclude that analysts are better forecasters than time series models based on the past earnings history and that analysts' forecasts are incorporated in share prices.

2. Harris [16] provides a discussion of all three of these studies.

3. The results of such studies differ no doubt due in part to different samples and time periods. Studying samples of about fifty firms in the mid-1970s, Friend, Westerfield, and Granito [12] find the relationship between nonsystematic risk and expected return is stronger than that between beta and expected return. Focusing on the 1961–1968 period, Cragg and Malkiel [8] find just the opposite; they conclude that the relationship between beta and expected returns is stronger than that between nonsystematic risk and return. Studying approximately 400 stocks in the 1982–1985 period, Marston, Harris, and Crawford [23] find beta is significantly positively related to expected return. They find that nonsystematic risk is positively related to expected return in pairwise comparison but that this link disappears once beta is controlled for. Additionally, each of the three studies examines the role of disagreement among analysts as a proxy for risk. While research on analysts' disagreement holds promise, such disagreement appears highly collinear with the traditional measures of systematic and nonsystematic risk, thus complicating interpretation of results. Furthermore, as noted by Strock [29], measured disagreement may be contaminated by delays in reporting by analysts.

4. In concentrating on a single index model of risk (e.g., the CAPM, Sharpe [26]), we depart from the mainstream of recent work that focuses on tests of Ross's Arbitrage Pricing Theory (APT) [25], research which in part stems from dissatisfaction with empirical findings on the two-parameter CAPM. This work on APT explores pricing of multiple factors (e.g., Chen, Roll, and Ross [5]) and improvements in estimation techniques (e.g., McElroy and Burmeister [24]). Despite their contributions, empirical studies of APT to date have used realized returns.

5. While weighting schemes other than a simple average of analysts have theoretical appeal (Winkler and Makridakis [32]), some empirical evidence suggests that, at least in terms of forecast accuracy, equal weighting may be a superior choice to elaborate attempts to construct optimal weighting schemes (Ashton and Ashton [2] and Conroy and Harris [7]).

6. Firms for which the standard deviation of individual FAF exceeded twenty in any month were excluded from the analyses since we suspect some of these may involve errors in data entry. This screen resulted in excluding only a very small percentage of companies.

7. An alternative to this two-step procedure is to estimate betas and risk premiums simultaneously, which avoids the errors in variables problem associated with regressing returns on estimates in the second stage regression. Gibbons [13] suggests this approach in the context of the CAPM, and McElroy and Burmeister [24] develop the approach more fully as applied to the APT framework. We focus on the traditional two-step methodology so our work will be comparable to earlier studies. Additionally, as argued by Tinic and West ([30], pp. 141–142), the basic assumptions underlying multivariate tests (Gibbons [13], Stambaugh [27]) as applied to realized returns are the same as those behind the simpler Fama-Macbeth; furthermore, some of the finite sample properties of the multivariate tests are open to question. As applied to expected returns, we assume that beta (and other risk measures) derived from historical data are reasonable instruments for investors' perceptions of future risk. Since many investment advisory services publish betas derived from historical data, this appears a reasonable assumption, though further research in this area is needed.

8. To estimate these effects, we multiply the estimated coefficient by the standard deviations from Table 1. For beta squared and residual risk, the effects are (−0.0078) (0.4243) = −0.0033 and (−0.3593) (0.0090) = −0.0032, respectively.

9. For example, the correlation between residual risk and beta squared is 0.911. This is calculated as the simple average over seventy-two months of the correlation for the twenty portfolios in each month.

10. In addition to the results reported below, we tested for a January effect that Tinic and West [30] found in the relationship between realized return and risk. We averaged the estimated results of regression (1) using only January data and then again using the rest of the year. The data do not provide strong support for the hypothesis that the January effect reflects changes in expected returns or expected return's relationship to risk. We repeated the process for each month of the year, revealing no seasonal patterns in the parameters. Given that our proxies for expected returns assume a long holding period, it is not surprising that they do not reflect any strong seasonal pattern. Furthermore, having only six years of data makes such detection difficult.

We also tested whether the relationship between expected returns and risk variables is sensitive to the number of analysts that provide earnings forecasts. To address this issue, we segregated the sample firms into two groups in each month based on analysts' following. A "low analyst following" firm was followed by less than or equal to the mean number of analysts for the month, while a "high analyst following" firm had forecasts from a greater-than-average number of analysts. The regressions in Table 3 (for individual securities) were then estimated separately for the "low" versus "high" analyst groups. Results for each subsample were quite similar, both in terms of sign and magnitude, to those reported in Table 3.

11. The coefficients in Table 4 must be interpreted with caution since there is some evidence of model misspecification. Omission of variables related to changing risk premiums will bias the estimated slope coefficients unless such variables are uncorrelated with interest rates.

We first estimated the regressions in Table 4 using ordinary least squares (OLS), but low Durbin-Watson statistics suggested the presence of serial correlation. When the regressions were reestimated adjusting for serial correlation (using the Prais-Winsten procedure in SAS), the slope coefficients (reported in Table 4) were substantially lower than the OLS estimates. Since, in an appropriately specified model, the coefficient estimates should be robust to autocorrelation corrections, we suspect the serial correlation in residuals may itself be due to omitted variables. If such omitted variables are themselves correlated with interest rates, then the autocorrelation-adjusted estimates will be no more efficient or appropriate than OLS estimates. See Maddala [20], p. 291, and Kennedy [18], p. 79.

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Tab W

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THE MARKET RISK PREMIUM: EXPECTATIONAL ESTIMATES USING ANALYSTS' FORECASTS

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The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts

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The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts

Abstract

We use expectational data from financial analysts to estimate a market risk premium for U.S. stocks. Using the SP500 as a proxy for the market portfolio, we find an average market risk premium of 7.14% above yields on long-term U.S. government bonds over the period 1982-1998. We also find that this risk premium varies over time and that much of this variation can be explained by either the level of interest rates or readily available forward-looking proxies for risk. The market risk premium appears to move inversely with government interest rates suggesting that required returns on stocks are more stable than interest rates themselves.

The Market Risk Premium: Expectational Estimates Using Analysts' Forecasts

The notion of a market risk premium (the spread between investor required returns on safe and average risk assets) has long played a central role in finance. It is a key factor in asset allocation decisions to determine the portfolio mix of debt and equity instruments. Moreover, the market risk premium plays a critical role in the Capital Asset Pricing Model (CAPM), practitioners most widely used means of estimating equity hurdle rates. In recent years, the practical significance of estimating such a market premium has increased as firms, financial analysts and investors employ financial frameworks to analyze corporate and investment performance. For instance, the increased use of Economic Value Added to assess corporate performance has provided a new impetus for estimating capital costs.

The most prevalent approach to estimating the market risk premium relies on some average of the historical spread between returns on stocks and bonds.[1] This choice has some appealing characteristics but is subject to many arbitrary assumptions such as the relevant period for taking an average. Compounding the difficulty of using historical returns is the well noted fact that standard models of consumer choice would predict much lower spreads between equity and debt returns than have occurred in U.S. markets—the so called equity premium puzzle (see Welch (1998), Siegel and Thaler (1997)). In addition, theory calls for a forward looking risk premium that could well change over time.

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[1] Bruner, Eades, Harris and Higgins (1998) provide survey evidence on both textbook advice and practitioner methods for estimating capital costs. Despite substantial empirical assault, the CAPM continues to play a major role in applied finance. As testament to the market for cost of capital estimates Ibbotson Associates (1998) publishes a "Cost of Capital Quarterly."

This paper takes an alternate approach by using expectational data to estimate the market risk premium. The approach has two major advantages for practitioners. First, it provides an independent estimate which can be compared to historical averages. At a minimum, this can help in understanding likely ranges for risk premia. Second, expectational data allow investigation of changes in risk premia over time. Such time variations in risk premia serve as important signals from investors that should affect a host of financial decisions.

The paper updates and extends earlier work (Harris (1986), Harris and Marston (1992)) which incorporates financial analysts' forecasts of corporate earnings growth. Updating through 1998 provides an opportunity to see whether changes in the risk premium are in part responsible for the run up in share prices in the bull market. In addition, we provide new tests of whether changes in risk premia over time are linked to forward-looking measures of risk. Specifically, we look at the relationship between the risk premium and four ex-ante measures of risk: the spread between yields on corporate and government bonds, consumer sentiment about future economic conditions, the average level of dispersion across analysts as they forecast corporate earnings and the implied volatility on the SP500 Index derived from options data.

Section I provides background on the estimation of equity required returns and a brief discussion of current practice in estimating the market risk premium. In Section II, models and data are discussed. Following a comparison of the results to historical returns in Section III, we examine the time-series characteristics of the estimated market premium in Section IV. Finally, conclusions are offered in Section V.

I. Background

The notion of a "market" required rate of return is a convenient and widely used construct. Such a rate (k) is the minimum level of expected return necessary to compensate investors for bearing the average risk of equity investments and receiving dollars in the future rather than in the present. In general, k will depend on returns available on alternative investments (e.g., bonds). To isolate the effects of risk, it is useful to work in terms of a market risk premium (rp), defined as

$$rp = k - i, \tag{1}$$

where i = required return for a zero risk investment.

Lacking a superior alternative, investigators often use averages of historical realizations to estimate a market risk premium. Bruner *et al.* (1998) provide recent survey results on best practices by corporations and financial advisors. While almost all respondents used some average of past data in estimating a market risk premium, a wide range of approaches emerged. "While most of our 27 sample companies appear to use a 60+- year historical period to estimate returns, one cited a window of less than ten years, two cited windows of about ten years, one began averaging with 1960, and another with 1952 data" (p. 22). Some used arithmetic averages and some geometric. This historical approach requires the assumptions that past realizations are a good surrogate for future expectations and, as typically applied, that the risk premium is constant over time. Carleton and Lakonishok (1985) demonstrate empirically some of the problems with such historical premia when they are dissaggregated for different time periods or groups of firms. As Bruner *et al* (1998) point out, few respondents cited use of expectational data to supplement or replace historical returns in estimating the market premium.

Survey evidence also shows substantial variation in empirical estimates. When respondents gave a precise estimate of the market premium, they cited figures from 4 to over 7 percent (Bruner *et al* 1998). A quote from a survey respondent highlights the range in practice. "In 1993, we polled various investment banks and academic studies on the issue as to the appropriate rate and got anywhere between 2 and 8%, but most were between 6 and 7.4%." (Bruner *et al* 1998, p. 23). An informal sampling of current practice also reveals large differences in assumptions about an appropriate market premium. For instance, in a 1999 application of EVA analysis, Goldman Sachs Investment Research specifies a market risk premium of "3%

from 1994-1997 and 3.5% from 1998-1999E for the S&P Industrials" (Goldman Sachs (1999, p. 59)). At the same time an April 1999 phone call to Stern Stewart revealed that their own application of EVA typically employed a market risk premium of 6%. In its application of the CAPM, Ibbotson Associates (1998) uses a market risk premium of 7.8%. Not surprisingly, academics don't agree on risk premium either. Welch (1998) surveyed leading financial economists at major universities. For a 30-year horizon, he found a mean risk premium of 6.12% but a range from 2% to 9% with an interquartile range of 2% (based on 104 responses).

To provide additional insight on estimates of the market premium, we use publicly available expectational data. This expectational approach employs the dividend growth model (hereafter referred to as the discounted cash flow or DCF model) in which a consensus measure of financial analysts' forecasts (FAF) of earnings is used as a proxy for investor expectations. Earlier works by Malkiel (1982), Brigham, Vinson, and Shome (1985), Harris (1986) and Harris and Marston (1992) have used FAF in DCF models[2].

II. Models and Data

We employ the simplest and most commonly used version of the DCF model to estimate shareholders' required rate of return, k, as shown in Equation (2):

$$k = \left(\frac{D_1}{P_0}\right) + g, \tag{2}$$

where D_1 = dividend per share expected to be received at time one, P_0 = current price per share (time 0), and g = expected growth rate in dividends per share[3]. A primary difficulty in using the

[2] Ibbotson Associates (1998) use a variant of the DCF model with forward-looking growth rates as one means to estimate cost of equity; however, they do this as a separate technique and not as part of the CAPM. For their CAPM estimates they use historical averages for the market risk premium. The DCF approach with analysts' forecasts has been used frequently in regulatory settings.

[3] Our methods follow Harris (1986) and Harris and Marston (1992) who provide an overview of earlier research and a detailed discussion of the approach employed here. For instance, theoretically, i is a risk-free rate, though empirically its proxy (e.g., yield to maturity on a government bond) is only a "least risk" alternative that is itself subject to risk. They also discuss single versus multistage growth discounted cash flow models and procedures used in calculating the expected dividend yield. While the model calls for expected growth in dividends, in the long run, dividend growth is sustainable only via growth in earnings. As long as payout ratios are not expected to change, the two growth rates will be the same.

DCF model is obtaining an estimate of *g*, since it should reflect market expectations of future performance. This paper uses published FAF of long-run growth in earnings as a proxy for g. Equation (2) can be applied for an individual stock or any portfolio of companies. We focus primarily on its application to estimate a market premium as proxied by the SP500.

FAF come from IBES Inc. The mean value of individual analysts' forecasts of five-year growth rate in EPS is used as our estimate of *g* in the DCF model. The five-year horizon is the longest horizon over which such forecasts are available from IBES and often is the longest horizon used by analysts. IBES requests "normalized" five-year growth rates from analysts in order to remove short-term distortions that might stem from using an unusually high or low earnings year as a base. Growth rates are available on a monthly basis.

Dividend and other firm-specific information come from COMPUSTAT. D_1 is estimated as the current indicated annual dividend times (1+g). Interest rates (both government and corporate) are gathered from Federal Reserve Bulletins and *Moody's Bond Record*. Table 1 describes key variables used in the study. Data are collected for all stocks in the Standard & Poor's 500 stock (SP500) index followed by IBES. Since five-year growth rates are first available from IBES beginning in 1982, the analysis covers the period from January 1982-December 1998.

We generally adopt the same approach as used in Harris and Marston (1992). For each month, a market required rate of return is calculated using each dividend paying stock in the SP500 index for which data are available. As additional screens for reliability of data, in a given month we eliminate a firm if there are fewer than three analysts' forecasts or if the standard deviation around the mean forecast exceeds 20%. Combined these two screens eliminate fewer than 20 stocks a month. Later we report on the sensitivity of our results to various screens. The DCF model in Equation (2) is applied to each stock and the results weighted by market value of equity to produce the market-required return.[4] The risk premium is constructed by subtracting the interest rate on government bonds.

For short-term horizons (quarterly and annual), past research (Brown, 1993) finds that on average analysts' forecasts are overly optimistic compared to realizations. However, recent research on quarterly horizons (Brown, 1997) suggests that analysts' forecasts for SP500 firms do not have an optimistic bias for the period 1993-1996. There is very little research on the properties of five-year growth forecasts, as opposed to shorter horizon predictions.[5] Any analysts' optimism is not necessarily a problem for our analysis. If investors share analysts' views, our procedures will still yield unbiased estimates of required returns and risk premia. In light of the possible bias, however, we interpret our estimates as "upper bounds" for the market premium.

To broaden our exploration, we tap four very different sources to create ex ante measures of equity risk at the market level. The first proxy comes from the bond market and is calculated as the spread between corporate and government bond yields (BSPREAD). The rationale is that increases in this spread signal investors' perceptions of increased riskiness of corporate activity that would be translated to both debt and equity owners. The second measure, CON, is the consumer confidence index reported by the Conference Board at the end of the month. While the reported index tends to be around 100, we rescale CON as the actual index divided by 100. We also examined use of CON as of the end of the prior month; however, in regression analysis

[4] We weighted 1998 results by year-end 1997 market values since our monthly data on market value did not extend through this period. Since we did not have data on firm-specific dividend yields for the last four months of 1998, we estimated the market dividend yield for these months using the dividend yield reported in the *Wall Street Journal* scaled by the average ratio of this figure to the dividend yield for our sample as calculated in the first eight months of 1998. We then made adjustments using growth rates from IBES to calculate the market required return. We also estimated results using an average dividend yield for the month which employed the average of the price at the end of the current and prior months. These average dividend yield measures led to essentially the same regression coefficients as those reported later in the paper but introduced significant serial correlation in some regressions (Durbin-Watson statistics significantly different from 2.0 at the .01 level).

[5] To our knowledge, the only studies of possible bias in analysts' five-year growth rates are Boebel (1991) and Boebel, Harris and Gultekin (1993). They both find evidence of optimism in IBES growth forecasts. In the most thorough study to date, Boebel (1991) reports that this bias seems to be getting smaller over time. His forecast data do not extend into the 1990's.

this lagged measure was generally not statistically significant in explaining the level of the market risk premium[6]. The third measure, DISP, measures the dispersion of analysts' forecasts. Such analyst disagreement should be positively related to perceived risk since higher levels of uncertainty would likely generate a wider distribution of earnings forecasts for a given firm. DISP is calculated as the equally weighted average of firm-specific standard deviations for each stock in the SP500 covered by IBES. The firm-specific standard deviation is calculated based on the dispersion of individual analysts' growth forecasts around the mean of individual forecasts for that company in that month. Our final measure, VOL, is the implied volatility on the SP500 index. As of the beginning of the month, we use a dividend adjusted Black Scholes Formula to estimate the implied volatility in the SP500 index option contract which expires on the third Friday of the month. The call premium, exercise price and the level of the SP500 index are taken from the *Wall Street Journal* and treasury yields come from the Federal Reserve. Dividend yield comes from DRI. We use the option contract that is closest to being at the money.

III. Estimates of the Market Premium

Table 2 reports both required returns and risk premia by year (averages of monthly data). The results are quite consistent with the patterns reported earlier (e.g., Harris and Marston, 1992). The estimated risk premia are positive, consistent with equity owners demanding additional rewards over and above returns on debt securities. The average expectational risk premium (1982 to 1998) over government bonds is 7.14%, slightly higher than the 6.47% average for 1982 to 1991 reported earlier (Harris and Marston, 1992). For comparison purposes, Table 3 contains historical returns and risk premia. The average expectational risk premium

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[6] We examined two other proxies for Consumer Confidence. The Conference Board's Consumer Expectations Index yielded essentially the same results as those reported. The University of Michigan's Consumer Sentiment Indices tended to be less significantly linked to the market risk premium though coefficients were still negative.

reported in Table 2 is approximately equal to the arithmetic (7.5%) long-term differential between returns on stocks and long-term government bonds.[7]

Table 2 shows the estimated risk premium changes over time, suggesting changes in the market's perception of the incremental risk of investing in equity rather than debt securities. Scanning the next to last column of Table 2, the risk premium is higher in the 1990's than earlier and especially so in late 1997 and 1998. Our DCF results provide no evidence to support the notion of a declining risk premium in the 1990's as a driver of the strong run up in equity prices.

A striking feature in Table 2 is the relative stability of our estimates of k. After dropping (along with interest rates) in the early and mid-1980's, the average annual value of k has remained within a 75 basis point range around 15 percent for over a decade. Moreover, this stability arises despite some variability in the underlying dividend yield and growth components of k as Table 2 illustrates. The results suggest that k is more stable than government interest rates. Such relative stability of k translates into parallel changes in the market risk premium. In a subsequent section, we examine whether changes in our market risk premium estimates appear linked to interest rate conditions and a number of proxies for risk[8].

We explored the sensitivity of our results to our screening procedures in selecting companies. Our reported results screen out all non-dividend paying stocks on the premise that use of the DCF model is inappropriate in such cases. The dividend screen eliminates an average of 55 companies per month. In a given month, we also screen out firms with fewer than three analysts' forecasts, or if the standard deviation around the mean forecast exceeds 20%. When we repeated our analysis without any of the screens, the average risk premium over the sample

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[7] Interestingly, for the 1982-1996 period the arithmetic spread between large company stocks and long-term government bonds was only 3.3% per year. The downward trend in interest rates resulted in average annual returns of 14.1% on long-term government bonds over this horizon. Some (e.g., Ibbotson, 1997) argue that only the income (not total) return on bonds should be subtracted in calculating risk premia.

[8] Although our focus is on the market risk premium, in earlier work (Harris and Marston (1992), Marston, Harris and Crawford (1993)), we examined the cross-sectional link between expectational equity risk premia at the firm level and beta and found a significant positive correlation. For comparative purposes, we replicated and updated that

period increased by only 40 basis points, from 7.14% to 7.54%. We also estimated the beta of our sample firms and found the sample average to be one, suggesting that our screens do not systematically remove low or high-risk firms. Specifically, using firms in our screened sample as of December 1997 (the last date for which we had CRSP return data), we used ordinary least squares regressions to estimate beta for each stock using the prior sixty months of data and the CRSP return (SPRTRN) as the market index. The value-weighted average of the individual betas was 1.00.

In the results reported here we use firms in the SP500 as reported by COMPUSTAT in September 1998 which could create a survivorship bias, especially in the earlier months of our sample. We compared our current results to those obtained in our earlier work (Harris and Marston (1992)) for which we had data to update the SP500 composition each month. For the overlapping period, January 1982-May 1991 the two procedures yield the same average market risk premium, 6.47%. This suggests that the firms departing from or entering the SP500 index do so for a number of reasons with no discernable effect on the overall estimated SP500 market risk premium.

IV. Changes in the Market Risk Premium Over Time

With changes in the economy and financial markets, equity investments may be perceived to change in risk. For instance, investor sentiment about future business conditions likely affects attitudes about the riskiness of equity investments compared to investments in the bond markets. Moreover, since bonds are risky investments themselves, equity risk premia (relative to bonds) could change due to changes in perceived riskiness of bonds, even if equities displayed no shifts in risk.

In earlier work covering the 1982-1991 period, Harris and Marston (1992) reported regression results indicating that the market premium decreased with the level of government

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analysis through 1998 and reached very similar conclusions. At the firm level our expectational estimates of risk interest rates and increased with the spread between corporate and government bond yields (BSPREAD). This bond yield spread was interpreted as a time series proxy for equity risk. We introduce three additional ex ante measures of risk shown in Table 1: CON, DISP and VOL. The three measures come from three independent sets of data and are supplied by different agents in the economy (consumers, equity analysts and investors (via option and share price data)). Table 4 provides summary data on all four of our risk measures.

Table 5 replicates and updates earlier analysis.[9] The results confirm the earlier patterns. For the entire sample period, Panel A shows that risk premia are negatively related to interest rates. This negative relationship is also true for both the 1980's and 1990's as displayed in Panels B and C. For the entire 1982 to 1998 period, the addition of the yield spread risk proxy to the regressions lowers the magnitude of the coefficient on government bond yields, as can be seen by comparing Equations 1 and 2 of Panel A. Furthermore, the coefficient of the yield spread (0.487) is itself significantly positive. This pattern suggests that a reduction in the risk differential between investment in government bonds and in corporate activity is translated into a lower equity market risk premium.

In major respects, the results in Table 5 parallel earlier findings. The market risk premium changes over time and appears inversely related to government interest rates but positively related to the bond yield spread, which proxies for the incremental risk of investing in equities as opposed to government bonds. One striking feature is the large negative coefficients on government bond yields. The coefficients indicate the equity risk premium declines by over 70 basis points for a 100 basis point increase in government interest rates.[10] This inverse

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premia are significantly positively correlated to beta.

[9] OLS regressions with levels of variables generally showed severe autocorrelation. As a result, we used the Prais-Winsten method (on levels of variables) and also OLS regressions on first differences of variables. Since both methods yielded similar results and the latter had more stable coefficients across specifications, we report only the results using first differences. Tests using Durbin-Watson statistics from regressions in Tables 5 and 6 do not accept the hypothesis of autocorrelated errors (tests at .01 significance level, see Johnston 1984, pp. 321-325).

[10] The Table 5 coefficients on i are significantly different from -1.0 suggesting that equity required returns do respond to interest rate changes. However, the large negative coefficients imply only minor adjustments of required

relationship suggests much greater stability in equity required returns than is often assumed. For instance, standard application of the CAPM suggests a one-to-one change in equity returns and government bond yields.

Table 6 introduces three additional proxies for risk and explores whether these variables, either individually or collectively, are correlated with the market premium. Since our estimates of implied volatility start in May 1986, the table shows results for both the entire sample period and for the period during which we can introduce all variables. Entered individually each of the three variables is significantly linked to the risk premium with the coefficient having the expected sign. For instance, in regression (1) the coefficient on CON is -.014 which is significantly different from zero (t = -3.50). The negative coefficient signals that higher consumer confidence is linked to a lower market premium. The positive coefficients on VOL and DISP indicate the equity risk premium increases with both market volatility and disagreement among analysts. The effects of the three variables appear largely unaffected by adding other variables. For instance, in regression (4) the coefficients on CON and DISP both remain significant and are similar in magnitude to the coefficients in single variable regressions.

Even in the presence of the new risk variables, Table 6 shows that the market risk premium is affected by interest rate conditions. The large negative coefficient on government bond rates implies large reductions in the equity premium as interest rates rise. One feature of our data may contribute to the observed negative relationship between the market risk premium and the level of interest rates. Specifically, if analysts are slow to report updates in their growth forecasts, changes in our estimated *k* would not adjust fully with changes in the interest rate even if the true risk premium were constant. To address the impact of "stickiness" in the measurement of *k*, we formed "quarterly" measures of the risk premium which treat *k* as an average over the

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returns to interest rate changes since the risk premium declines. In earlier work (Harris and Marston (1991)) the coefficient was significantly negative but not as large in absolute value. In that earlier work we reported results quarter. Specifically, we take the value of k at the end of a quarter and subtract from it the average value of i for the months ending when k is measured. For instance, to form the risk premium for March 1998 we take the March value of k and subtract the average value of i for January, February and March. This approach assumes that in March k still reflects values of g that have not been updated from the prior two months. We then pair our quarterly measure of risk premium with the average values of the other variables for the quarter. For instance, the March 1998 "quarterly" risk premium would be paired with averaged values of BSPREAD over the January through March period. To avoid overlapping observations for the independent variables, we use only every third month (March, June, September, December) in the sample.

As reported in Table 7, sensitivity analysis using "quarterly" observations suggests that delays in updating may be responsible for a portion, but not all, of the observed negative relationship between the market premium and interest rates. For example, when we use quarterly observations the coefficient on i in regression (2) of Table 7 is -.527, well below the earlier estimates but still significantly negative[11].

As an additional test, we look at movements in the bond risk premium (BSPREAD). Since BSPREAD is constructed directly from bond yield data it does not have the potential for reporting lags that may affect analysts' growth forecasts. Regression 3 in Table 7 shows BSPREAD is negatively linked to government rates and significantly so[12]. While the equity premium need not move in the same pattern as the corporate bond premium, the negative coefficient on BSPREAD suggests that our earlier results are not due solely to "stickiness" in measurements of market required returns.

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using the Prais-Winsten estimators. When we use that estimation technique and recreate the second regression in Table 5, the coefficient for i is -.584 (t = 12.23) for the entire sample period 1982-1998.

[11] Sensitivity analysis for the 1982-1989 and 1990-1998 subperiods yields results similar to those reported.

[12] We thank Bob Conroy for suggesting use of BSPREAD. Regression 3 in Table 7 appears to have autocorrelated errors: the Durbin-Watson (DW) statistic rejects the hypothesis of no autocorrelation. However, in subperiod analysis, the DW statistic for the 1990-98 period is consistent with no autocorrelation and the coefficient on i is essentially the same (-.24, t = -8.05) as reported in Table 7.

The results in Table 7 suggest that the inverse relationship between interest rates and the market risk premium may not be as pronounced as suggested in earlier tables. Still, there appears to be a significant negative link between the equity risk premium and government interest rates. The quarterly results in Table 7 would suggest about a 50 basis point change in risk premium for each 100 basis point movement in interest rates.

Overall, our ex ante estimates of the market risk premium are significantly linked to ex ante proxies for risk. Such a link suggests that investors modify their required returns in response to perceived changes in the environment. The findings provide some comfort that our risk premium estimates are capturing, at least in part, underlying economic changes in the economic environment. Moreover, each of the risk measures appears to contain relevant information for investors. The market risk premium is negatively related to the level of consumer confidence and positively linked to interest rate spreads between corporate and government debt, disagreement among analysts in their forecasts of earnings growth and the implied volatility of equity returns as revealed in options data.

II. Conclusions

Shareholder required rates of return and risk premia are based on theories about investors' expectations for the future. In practice, however, risk premia are typically estimated using averages of historical returns. This paper applies an alternate approach to estimating risk premia that employs publicly available expectational data. The resultant average market equity risk premium over government bonds is comparable in magnitude to long-term differences (1926 to 1998) in historical returns between stocks and bonds. As a result, our evidence does not resolve the equity premium puzzle; rather, our results suggest investors still expect to receive large spreads to invest in equity versus debt instruments.

There is strong evidence, however, that the market risk premium changes over time. Moreover, these changes appear linked to the level of interest rates as well as ex ante proxies for risk drawn from interest rate spreads in the bond market, consumer confidence in future economic conditions, disagreement among financial analysts in their forecasts and the volatility of equity returns implied by options data. The significant economic links between the market premium and a wide array of risk variables suggests that the notion of a constant risk premium over time is not an adequate explanation of pricing in equity versus debt markets.

Our results have implications for practice. First, at least on average, our estimates suggest a market premium roughly comparable to long-term historical spreads in returns between stocks and bonds. Our conjecture is that, if anything, our estimates are on the high side and thus establish an upper bound on the market premium. Second, our results suggest that use of a constant risk premium will not fully capture changes in investor return requirements. As a specific example, our findings indicate that common application of models such as the CAPM will overstate changes in shareholder return requirements when government interest rates change. Rather than a one-for-one change with interest rates implied by use of constant risk premium, our results indicate that equity required returns for average risk stocks likely change by half (or less) of the change in interest rates. However, the picture is considerably more complicated as shown by the linkages between the risk premium and other attributes of risk.

Ultimately, our research does not resolve the answer to the question "What is the right market risk premium?" Perhaps more importantly, our work suggests that the answer is conditional on a number of features in the economy—not an absolute. We hope that future research will harness ex ante data to provide additional guidance to best practice in using a market premium to improve financial decisions.

Table 1. Variable Definitions

k	=	Equity required rate return.
P_0	=	Price per share.
D_1	=	Expected dividend per share measured as current indicated annual dividend from COMPUSTAT multiplied by $(1 + g)$.
g	=	Average financial analysts' forecast of five-year growth rate in earnings per share (from IBES).
i	=	Yield to maturity on long-term U.S. government obligations (source: Federal Reserve, 30-year constant maturity series).
rp	=	Equity risk premium calculated as $rp = k - i$.
BSPREAD	=	spread between yields on corporate and government bonds, BSPREAD = yield to maturity on long-term corporate bonds (Moody's average across bond rating categories) minus i.
CON	=	Monthly consumer confidence index reported by the Conference Board (divided by 100).
DISP	=	Dispersion of analysts' forecasts at the market level.
VOL	=	Volatility for the SP500 index as implied by options data.

Table 2. Bond Market Yields, Equity Required Return, and Equity Risk Premium, 1982-1998

Values are averages of monthly figures in percent. i is the yield to maturity on long-term government bonds, k is the required return on the SP500 estimated as a value weighted average using a discounted cash flow model with analysts' growth forecasts. The risk premium $rp = k - i$. The average of analysts' growth forecasts is g. *Div yield* is expected dividend per share divided by price per share.

Year	*Div yield*	g	K	i	$rp = k - i$
1982	6.89	12.73	19.62	12.76	6.86
1983	5.24	12.60	17.86	11.18	6.67
1984	5.55	12.02	17.57	12.39	5.18
1985	4.97	11.45	16.42	10.79	5.63
1986	4.08	11.05	15.13	7.80	7.34
1987	3.64	11.01	14.65	8.58	6.07
1988	4.27	11.00	15.27	8.96	6.31
1989	3.95	11.08	15.03	8.45	6.58
1990	4.03	11.69	15.72	8.61	7.11
1991	3.64	11.99	15.63	8.14	7.50
1992	3.35	12.13	15.47	7.67	7.81
1993	3.15	11.63	14.78	6.60	8.18
1994	3.19	11.47	14.66	7.37	7.29
1995	3.04	11.51	14.55	6.88	7.67
1996	2.60	11.89	14.49	6.70	7.79
1997	2.18	12.60	14.78	6.60	8.17
1998	1.80	12.95	14.75	5.58	9.17
Average	3.86	11.81	15.67	8.53	7.14

Table 3. Average Historical Returns on Bonds, Stocks, Bills, and Inflation in the U.S., 1926-1998

Historical Return Realizations	Geometric Mean	Arithmetic Mean
Common Stock (large company)	11.2%	13.2%
Long-term government bonds	5.3%	5.7%
Treasury bills	3.8%	3.8%
Inflation rate	3.1%	3.2%

Source: Ibbotson Associates, Inc., *1999 Stocks, Bonds, Bills and Inflation*, 1999 Yearbook.

Table 4. **Descriptive Statistics on Ex Ante Risk Measures**

Entries are based on monthly data. BSPREAD is the spread between yields on long-term corporate and government bonds. CON is the consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the SP500 index implied by options data. Variables are expressed in decimal form, e.g., 12% = .12.

A. Variable Monthly Levels	Mean	Standard Deviation	Minimum	Maximum
BSPREAD	.0123	.0040	.0070	.0254
CON	.9500	.2240	.473	1.382
DISP	.0349	.0070	.0285	.0687
VOL	.1599	.0696	.0765	.6085

B. Variable Monthly Changes	Mean	Standard Deviation	Minimum	Maximum
BSPREAD	-.00001	.0011	-.0034	.0036
CON	.0030	.0549	-.2300	.2170
DISP	-.00002	.0024	-.0160	.0154
VOL	-.0008	.0592	-.2156	.4081

C. Correlation Coefficients for Monthly Changes
*significantly different from zero at the .05 level
**significantly different from zero at the .01 level

	BSPREAD	CON	DISP	VOL
BSPREAD	1.00	-.16*	.05	.22**
CON	-.16*	1.00	.07	-.09
DISP	.05	.07	1.00	.03
VOL	.22**	-.09	.03	1.00

Table 5. Changes in the Market Equity Risk Premium Over Time

The table reports regression coefficients (*t*-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the SP500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as *i*. For purposes of the regression, variables are expressed in decimal form, e.g., 12% = .12.

Time period	Intercept	*i*	BSPREAD	R^2
A. 1982-1998	-.0002 (-1.49)	-.8696 (-16.54)		.57
	-.0002 (-1.11)	-.749 (-11.37)	.487 (2.94)	.59
B. 1980's	-.0005 (-1.62)	-.887 (-10.97)		.56
	-.0004 (-1.24)	-.759 (-7.42)	.508 (1.99)	.57
C. 1990's	-.0000 (-0.09)	-.840 (-13.78)		.64
	-.0000 (0.01)	-.757 (-9.85)	.347 (1.76)	.65

Table 6. Changes in the Market Equity Risk Premium Over Time and Selected Measures of Risk

The table reports regression coefficients (*t*-values). Regression estimates use all variables expressed as monthly changes to correct for autocorrelation. The dependent variable is the market equity risk premium for the SP500 index. BSPREAD is the spread between yields on long-term corporate and government bonds. The yield to maturity on long-term government bonds is denoted as *i*. CON is the change in consumer confidence index. DISP measures the dispersion of analysts' forecasts of earnings growth. VOL is the volatility on the SP500 index implied by options data. For purposes of the regression, variables are expressed in decimal form, e.g., 12% = .12.

Time period		Intercept	*i*	BSPREAD	CON	DISP	VOL	*Adj.* R^2
A. 1982-1998	(1)	0.0002 (.97)			-0.014 (-3.50)			0.05
	(2)	-0.0001 (-.96)	-0.737 (-11.31)	0.453 (2.76)	-0.007 (-2.48)			0.60
	(3)	0.0002 (.78)				0.244 (2.38)		0.02
	(4)	-0.0001 (-.93)	-0.733 (-11.49)	0.433 (2.69)	-0.007 (-2.77)	0.185 (3.13)		0.62
B. May 1986-1998	(5)	0.0000 (.03)	-0.821 (-11.16)	0.413 (2.47)	-0.005 (-2.22)	0.376 (3.74)		0.68
	(6)	0.0001 (.53)					0.011 (2.89)	0.05
	(7)	0.0000 (.02)	-0.831 (-11.52)	0.326 (1.95)	-0.005 (-2.12)	0.372 (3.77)	0.006 (2.66)	0.69

Table 7. Regressions Using Alternate Measures of Risk Premia to Analyze Potential Effects of Reporting Lags in Analysts' Forecasts

The table reports regression coefficients (*t*-values). Regression estimates use all variables expressed as changes (monthly or quarterly) to correct for autocorreclation. BSPREAD is the spread between yields on long-term corporate and government bonds. *rp* is the risk premium on the SP500 index. The yield to maturity on long-term government bonds is denoted as *i*. For purposes of the regression, variables are expressed in decimal form, e.g., 12% = .12.

Dependent Variable	Intercept	*i*	BSPREAD	*Adj.* R^2
(1) Equity Risk Premium (*rp*) Monthly Observations (same as Table 5)	-.0002 (-1.11)	-.749 (-11.37)	.487 (2.94)	.59
(2) Equity Risk Premium (*rp*) "Quarterly" nonoverlapping observations to account for lags in analyst reporting	-.0002 (-.49)	-.527 (-6.18)	.550 (2.20)	.60
(3) Corporate Bond Spread (BSPREAD) Monthly Observations	-.0001 (-1.90)	-.247 (-11.29)		.38

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