THE BARBADOS
LIGHT & POWER
COMPANY LIMITED

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COMMISSION SECRETARY
FAIR TRADING COMMISSION
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APPLICATION

PURSUANT TO SECTION 16
OF
THE UTILITIES REGULATION ACT
CAP. 282 OF THE LAWS OF BARBADOS

FOR A REVIEW OF ELECTRICITY RATES

FAIR TRADING COMMISSION
Mr. Peter Williams
Barbados Light + Power Co. Ltd
Date: May 8, 2009
Time: 4:30 p.m.
Place: Fair Trading Commission
"Good Hope" Green Hill St. Michael
Received by: Kim Griffith-Tang How

VOLUME 3

PW

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF PETER W. B. WILLIAMS

I PETER W.B. WILLIAMS, of No. 1 Brighton, in the parish of St. George, in this island, being duly sworn, **MAKE OATH** and say as follows:

1. I am the Managing Director of The Barbados Light & Power Company Limited ("the Applicant"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situate at Garrison Hill in the parish of St Michael. I am duly authorized to depose to the facts and matters in this Affidavit on behalf of the Applicant and the statement of facts herein are within my personal knowledge unless otherwise stated.

EDUCATIONAL & PROFESSIONAL EXPERIENCE AND CURRENT POSITION

2. I am a Mechanical Engineer by profession. I hold a Bachelor of Science degree in Mechanical Engineering which I obtained from Manchester University in the United Kingdom in 1977, a Master of Science degree in Electrical Power Systems which I received from the University of the West Indies in 1982 and a Master in Business Administration from the University of Western Ontario (Ivey School of Business) in Canada which I obtained in 1990. I attach a copy of my curriculum vitae marked as Exhibit "**PW 1**".

3. I joined the Applicant in 1977 as a trainee Generation Engineer and have been with the Applicant for over 30 years. In 1988 I resigned from the Applicant in order to pursue further studies in Canada. While in Canada I worked briefly with the Canadian International Power Services Inc. as part of a team of consultants on electric power projects for Caribbean and South American utilities. I returned to the employ of the Applicant in 1990 and assumed duties as a Senior Planning Engineer. As Senior Planning Engineer, I was the project manager for the then new gas turbine generating station and led investigations into alternative energy technologies, including wind energy and photovoltaic systems and worked with the team that successfully commissioned the Applicant's first grid-tied solar photovoltaic system. I was promoted in 2001 to Technical Services Manager. In 2004, I was appointed the Chief Operating Officer for the Applicant and assumed responsibility for oversight of technical operations including generation, transmission and distribution. I also had oversight of the Materials Management (Purchasing and Stores) section.

4. In July 2006, I was appointed the Managing Director of the Applicant and in my capacity as Managing Director I am responsible to the Board of Directors for the overall management of the Applicant. I set the overall strategic direction of the Applicant and work with the management and senior staff members to achieve the desired objectives. I also ensure compliance with the policies of the Applicant and I am responsible for compliance with all the regulations and laws which are applicable to the Applicant.

5. I am a registered professional engineer in Barbados, member and past President of the Barbados Association of Professional Engineers, a Chartered Engineer and member of the Institution of Mechanical Engineers in the United Kingdom and a member of the Institute of Electrical and Electronic Engineers Inc. (IEEE) of the United States of America.

THE APPLICATION

6. The purpose of my testimony is to introduce and provide an overview of the application for a review of electricity rates ("the Application") which has been made by the Applicant. I have prepared a General Memorandum which explains the purpose of the Application and gives a detailed overview. The

General Memorandum is found at Schedule A of the Application and it forms part of my written evidence in these proceedings.

7. The Applicant has worked assiduously over the past twenty six years to improve service quality and reliability, while maintaining basic electricity rates since the last increase was granted by the then Public Utilities Board in 1983. Regrettably, the present basic electricity rates which are set out at Schedules J-1 to J-8 of the Application are now inadequate to allow the Applicant to continue to meet the operating and maintenance expenses which have increased over the years as well as to attract new capital to replace older plant that is due for retirement. The Applicant therefore finds it necessary to make the Application to the Fair Trading Commission ("the Commission") for the following reasons:

   a. to provide the revenue required to meet the Applicant's expenses involved in supplying a service which is safe, adequate and reasonable and allow it to continue to deliver a secure and reliable supply of electricity to all customers in an environment where the cost of inputs to the Applicant's operations and maintenance have risen substantially;

   b. to attract new capital and to satisfy lenders of the Applicant's ability to repay loans and to maintain the confidence of investors by providing them with a fair and reasonable return in order that the Applicant can buy the plant and equipment required for the delivery of service to customers;

   c. to design rates such that the price of electricity to customers is closer to the cost of supplying the service, thereby providing correct price signals to all customers and encouraging energy efficiency;

   d. to provide new rate options for commercial customers on a pilot basis; and

   e. to provide, on a pilot basis for a period of three years, a renewable energy tariff rider for small customer-owned renewable energy generation sources which will feed energy into the electric grid.

8. In addition to my General Memorandum, the Application is supported by the following Memoranda of Support:

   (a) Memorandum on Test Year – Schedule B;
   (b) Memorandum on Rate Base – Schedule C;
   (c) Memorandum on Income Statement – Schedule D;
   (d) Memorandum on Self-Insurance Fund – Schedule E;
   (e) Memorandum on Rate of Return – Schedule F;
   (f) Memorandum on Revenue Requirement – Schedule G;
   (g) Memorandum on Sales Projections – Schedule H;
   (h) Memorandum on Capital Expansion 2009-2013 – Schedule I;
   (i) Memorandum on Proposed Tariffs – Schedule K;
   (j) Memorandum on Five Year Financial Forecasts – Schedule L; and
   (k) Memorandum on Standards of Service – Schedule M.

9. The Application is also supported by the Affidavits of Hutson R. Best, Stephen T. Worme and Mark St. C. King, three of the Applicant's Managers, and expert evidence provided in Affidavits by Robert Camfield of Christensen Associates Energy Consulting LLC (CAEC) on the Cost of Capital and Rate of Return, and Michael O'Sheasy also of CAEC on the Cost of Service.

10. I also prepared the Memoranda on the Test Year, the Self Insurance Fund and the Rate of Return, which are found at Schedules B, E and F respectively, of the Application. In the preparation of the Memoranda I had access to the studies prepared by the Applicant's consultants and other information supplied by them.. To the best of my knowledge, information and belief, the facts and matters set out in the Affidavit and each Memorandum are true. They form part of my written evidence in these proceedings.

GENERAL MEMORANDUM

11. In the General Memorandum I outline the reasons for the Application and review the trend in electricity prices from 1983 to 2008. I also discuss the Applicant's operating and financial performance, the present and proposed rates, the forecasts on present and proposed rates and conclude my analysis

by addressing how the Applicant intends to meet its customer needs of the future.

12. A secure and reliable supply of electricity is vital to the economic prosperity of Barbados and the Applicant strives to be an efficient organization with a strong focus on meeting customer needs. Electricity customers in Barbados have been served by the Applicant and its predecessor, the Barbados Electric Supply Corporation, since 1911. The Applicant is a wholly owned subsidiary of Light & Power Holdings Ltd., a company that at December 31, 2008 was approximately 60% locally owned by some 2,700 Barbadian shareholders and which is listed on the Barbados Stock Exchange. The Applicant operates under a franchise which was granted under Schedule 2 of the **Barbados Light and Power Company (Extension of Franchise) Act** 1982 to supply energy for all public and private purposes for a period of 42 years from August 1, 1986.

13. As of December 31, 2008, the Applicant was serving a total of 118,798 customers through an island-wide distribution network, had a peak demand of 164, 000 kilowatts and year-end sales of 944,035,752 kilowatt-hours.

14. The Applicant adheres to strict maintenance schedules to ensure that its plant and equipment are kept in good order and achieve high levels of availability and reliability. The low speed diesel generators which were installed in 1982 have achieved among the highest number of running hours for this type of plant around the world, still have high levels of availability and continue to operate as base load plant.

15. With the increasing cost of energy, efficiency of the electricity network continues to be a high priority for the Applicant. System losses, which are a measure of the efficiency of the transmission and distribution network, are inherent in the operation of an electricity system. Since 1983, the Company's losses steadily reduced as higher levels of efficiency were achieved. These losses are now among the lowest in the region and comparable to those of efficient utilities in North America and Europe.

16. It has been estimated that the cost of an electricity outage to the economy is a multiple of the cost of the electricity that would otherwise have been supplied during that outage. Countries with unreliable electricity systems cannot expect

to maintain a healthy and vibrant economy in this modern technological era. The Applicant continues to strive for increasing levels of system reliability which have been in the order of 99.9% during the past few years. The Applicant needs to continue to invest in order to prevent degradation of reliability. Once reliability suffers, it can take years to overcome the damage done to the economy.

17. Effective June 1, 2006 the Commission established Guaranteed Standards of Service and Overall Standards of Service for the Applicant as shown at Schedule M-1 of the Application. To date, the Applicant has had a high level of compliance with these Standards. The proposed rates which are provided at Schedules K-1 to K-11 of the Application are consistent with the Applicant's Guaranteed Standards of Service and Overall Standards of Service.

18. The Applicant is currently not receiving an adequate return for its investment on the existing rates. A continuing decline in earnings would negatively impact on the Applicant's ability to satisfy lenders for new loans required for expansion of the system and to replace ageing plant. As a result, the Applicant is seeking to have the Commission approve the following as outlined in the Memorandum on Proposed Tariffs:

(i) a revision of electricity rates effective October 1, 2009 for the following tariff groups: Domestic Service; General Service; Secondary Voltage Power; Large Power; Employee and Street Lights;

(ii) the implementation of a new Time-of-Use Tariff, an Interruptible Service Rider and a Renewable Energy Rider, all on a pilot basis;

(iii) a revised Fuel Clause; and

(iv) new Service Charges.

19. The Applicant's proposed rate design was guided by an Embedded Cost of Service Study for 2008 and load research carried out in 2007 and 2008 by CAEC, using data collected from special meters that were installed by the Applicant at customers' premises for that purpose. An analysis of marginal costs was also undertaken to assist with tariff design.

20. The Applicant's objective is to ensure that customers are provided with a reliable supply of electricity at reasonable rates. The Applicant has taken care to ensure that while one of its objectives in seeking a review of electricity rates is to give consumers efficient price signals about the true cost of electricity service, the Applicant is at this time only proposing a partial rebalancing of the rates so as to avoid rate shock. The Applicant is cognizant of the need to provide a basic supply of electricity at reasonable rates, especially to low-income earners. In the case of the Domestic Service tariff, the proposed rates are designed to lessen the impact of the revenue increase on customers in the lower income bracket. Inadequate rates and inappropriate rate structures do not benefit anyone, customers or investors, and can result in significant cost to the economy through insufficient investment and resulting declines in the availability and reliability of electricity supply.

21. The Applicant is also keen on encouraging energy saving and conservation amongst its customers. As such it proposes to maintain an inclining block rate structure in the Domestic Service tariff category and to introduce this in the General Service and Employee tariff categories.

22. The Applicant is also proposing to encourage renewable energy through a feed-in tariff rider for small customer owned renewable energy sources into the grid on a pilot basis.

23. The Applicant believes that a robust and reliable electric system is critical to the future development of Barbados and remains committed to providing an excellent service to its customers. The Applicant continues to expand and improve its generation, transmission and distribution facilities in order to meet the growing demand for electricity and as such is presently cooperating with the government and other interested parties to develop renewable energy projects. The Applicant has achieved universal service and contributed to the island's reputation for sound infrastructure and reliability, and needs to ensure that there is a continuation of a secure and reliable supply of electricity. The Applicant will only be in a position to do so if it is granted the requested increase in rates and other relief as set out in its Application.

MEMORANDUM ON TEST YEAR

24. The Applicant with the permission of the Commission has selected 2008 as the Test Year for the measurement of total revenues and costs in conducting operations over an audited twelve month period.

MEMORANDUM ON RATE OF RETURN

25. In the Memorandum on Rate of Return I discuss the Applicant's cost of debt, return on equity, dividend payout and capital structure. The Applicant is requesting that the Commission set the authorized Rate of Return on Rate Base, which embodies a return on equity, at a level that satisfies fair rate of return regulatory principles such that the return should be reasonably sufficient to assure confidence in the financial soundness of the utility.

26. The Applicant is seeking an overall Rate of Return on Rate Base of 10.48% which is the Applicant's Weighted Average Cost of Capital (WACC) stated on a regulatory basis, including the weighted combination of the Applicant's cost rates for debt and other sources of funds, and a fair rate of return on equity. The Return on Equity (ROE), the cost of debt, and the WACC have been determined from the "Study of the Cost of Capital and Rate of Return Recommendation" ("the Study") prepared by CAEC and dated May 20, 2008. This requested Rate of Return is very close to that estimated by NERA Economic Consulting in its regulatory audit of the Applicant in 2006.

27. In the calculation of the rate base the Applicant has only included plant which it has determined to be "used and useful". The Memorandum on Rate Base sets out the details of how the rate base was calculated.

28. The Rate of Return on Rate Base on existing rates for the Test Year 2008 adjusted for known and measurable changes is calculated to be 6.07%. This constitutes a significant shortfall for the Applicant.

29. The Applicant's revenue for the 2008 Test Year adjusted for known and measurable changes is calculated at $474,016,811. The Applicant is seeking an increase in revenue of $28,221,603 which would represent an increase of about 5.95% in overall electricity prices including the Fuel Clause Adjustment,

based on actual 2008 fuel cost. If this request is granted, it would provide the Applicant with the opportunity to earn the Return on Rate Base of 10.48% which the Study has concluded is a fair and reasonable return. The Affidavit of Hutson Best and the various memoranda prepared by him outline further details of the revenue requirement, income statement, rate base and five year financial forecasts.

30. The Debt/Equity (D/E) ratio of the Applicant has varied over the years based on the investment in new plant and equipment. The Applicant's capital structure at December 31, 2008 was made up of 19.2% Debt and 80.8% Equity. The relatively low debt has come about because of the significant reinvestment by the Applicant's shareholder. The Applicant is entering a period where significant investment in new plant will be required to replace plant that is due to be retired and to meet the increased demand for electricity. It is anticipated that the Applicant's debt will increase during the period 2009 to 2013, as outlined in the Memorandum on Five Year Financial Forecasts. The Applicant considers therefore that the present capital structure would not be appropriate in calculating the WACC and has therefore used a capital structure that better matches the D/E ratio for the period during which the proposed new tariffs will apply. The Applicant is seeking the Commission's approval to use a capital structure of Debt 35%, Equity 65% in the calculation of the overall WACC.

MEMORANDUM ON SELF-INSURANCE FUND

31. This Memorandum outlines how the Applicant insures its assets against catastrophe. Faced with the situation where (a) only a limited amount of commercial insurance was available to cover the Applicant's transmission and distribution systems against hurricane, and (b) what was available was prohibitively expensive, the Applicant decided to establish a Self-Insurance Fund ("the Fund"). The Fund received governmental and legislative approval when in 1998 the **Insurance Act** (1996-32) was amended and the **Insurance (Barbados Light and Power Company Limited) (Self Insurance Fund) Regulations 1998**, enacted. These Regulations were later amended in 2005 to allow for other risks to be covered.

32. The Fund is created by a Deed of Trust dated December 31, 1998 and must be accounted for separately from the Applicant's normal business activities. The Fund is regulated by the Supervisor of Insurance.

CONCLUSION

33. The Applicant provides a safe, secure and reliable electricity service to its customers. However, in order to continue providing this type of service in a manner that maintains customer satisfaction levels and earn a fair and reasonable return on its investment, it requires an increase in electricity rates, commencing on October 1, 2009. In the circumstances, the Applicant humbly requests that the Commission grant the Order being sought in its Application for a Review of Electricity Rates.

SWORN TO by **PETER W.B. WILLIAMS**)
at the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

....
PETER W.B. WILLIAMS

Before me:

....
LEGAL ASSISTANT

PW1

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

EXHIBIT "PW 1"

This is a copy of my curriculum vitae marked Exhibit "**PW 1**" mentioned and referred to in paragraph 2 of my Affidavit.

SWORN TO by **PETER W.B. WILLIAMS**)
at the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

....
PETER W.B. WILLIAMS

Before me:

....
LEGAL ASSISTANT

PETER W. B. WILLIAMS

1 Brighton
St. George, BARBADOS

EXPERIENCE

July 2006 – Present **The Barbados Light & Power Co. Ltd.**
Managing Director
- Responsible to the Board of Directors for overall management of the Company
- Set overall strategic direction of the Company
- Work with the management and senior staff team to achieve desired objectives.
- Establish policy and responsible for compliance

2004 – 2006 **The Barbados Light & Power Co. Ltd.**
Chief Operating Officer
- Responsible for oversight of technical operations including generation, transmission and distribution.
- Provided oversight of the Materials Management (Purchasing & Stores) section.

2001 – 2004 **The Barbados Light & Power Co. Ltd.**
Technical Services Manager
- Responsible for the Technical Services Department which provided overall technical planning services for the Company.
- Oversight of the Materials Management section of the Company.

1990 – 2001 **The Barbados Light & Power Co. Ltd.**
Senior Planning Engineer
- Project Manager for new gas turbine generating station including discussions on project financing.
- Coordinated Environmental Impact Assessment for generation expansion, including environmental audits and site selection.
- Led investigations into alternative energy technologies, including wind energy and photovoltaics, and worked with the team that successfully commissioned the Company's first grid-tied solar photovoltaic system.
- Coordinated engineering studies, including review and evaluation of proposals from suppliers and consultants.
- Responsible for distribution construction standards.
- Prepared tender documents and evaluated bids for distribution equipment.
- Organized seminars to improve communications with electrical contractors and engineers to better meet customer needs.
- Member of joint union / management job evaluation committee which undertook a major review of all the bargaining unit jobs.
- Led a team that developed and implemented a performance bonus system based on Corporate Key Performance Indicators.

1989	**Canadian Internation Power Services Inc.**, Mississauga, Ontario *Consultant* - Worked briefly as part of a team consulting on electric power projects for Caribbean and South American Utilities. - Prepared contract agreements with sub-consultants. - Reviewed technical proposals and prepared evaluation reports.
1983 – 1988	**The Barbados Light & Power Co. Ltd.** *Station Superintendent* - Responsible for maintenance and operating staff of about 40 persons. - Directed improvements in plant availability and reliability. - Recruited new staff and conducted staff appraisals. - Prepared operating budgets and monitored operating costs.
1977 – 1983	**The Barbados Light & Power Co. Ltd.** *Generation Engineer (Trainee)* - Scheduled maintenance on generating plant. - Directed work on plant refurbishment, including successful retrofit of medium speed diesel generators to operate on residual fuel oil. - Provided staff training.

EDUCATION

1990	**The University of the Western Ontario** *(Ivey School of Business)* *MBA*
1982	**The University of the West Indies** *MSc (Electrical Power Systems)*
1977	**Manchester University (U.K.)** *BSc (Mechanical Engineering)*

MEMBERSHIPS

Member, The Institution of Mechanical Engineers, U.K.
Chartered Engineer, U.K.
Member, IEEE
Member & Past President, Barbados Association of Professional Engineers

ACTIVITIES

Violin – Founder, Suzuki Music (Barbados) Inc.
Board Member, St. Patrick's R.C. School

HB

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF HUTSON R. BEST

I HUTSON R. BEST, of No. 15 Seaview Road, Chancery Lane in the parish of Christ Church in this island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am the Chief Financial Officer of The Barbados Light & Power Company Limited ("the Applicant"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situate at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the facts and matters in this Affidavit and the statement of facts herein are within my personal knowledge unless otherwise stated.

EDUCATIONAL & PROFESSIONAL EXPERIENCE AND CURRENT POSITION

2. I am a Certified Accountant by profession. I obtained my qualifications from the Association of Chartered Certified Accountants (United Kingdom) and I hold a Master in Business Administration from the University of the West Indies. As part of my ongoing professional development and training, I have participated in various courses. I have participated in the Corporate Financial Management Programme at the University of Michigan Business School, the Utility

Management Development Programme with US consulting firm, Stone & Webster Management Consultants, Driving Corporate Performance at Harvard Business School, the Utility Rate School conducted by the University of Florida Division of Continuing Education and the National Association of Regulatory Utility Commissioners, and other training on the Role of the Chief Financial Officer at the University of Pennsylvania (Wharton Business School) and at the American Management Association.

3. Prior to joining the Applicant and between the period 1983 to 1987, I worked as an Audit Senior at Ernst & Young, an International firm of Chartered Accountants, where I was responsible for supervising the audits of its large and varied clientele and assisting clients with improvements to their internal controls and systems reviews. Between 1987 and 1990, I worked as the Financial Controller for Plantations Holdings Limited, a retail food and hardware group, where I was responsible for all financial reporting and budgeting of the group. During the period 1991 to 1994, I worked as Treasurer and Assistant Vice President of Finance for the Barbados Mutual Life Assurance Society (now Sagicor) where I was responsible for all financial, budgeting and regulatory reporting of the Group throughout the Caribbean.

4. I am a Fellow of the Association of Chartered Certified Accountants (United Kingdom) and a Fellow of the Institute of Chartered Accountants of Barbados. I attach a copy of my curriculum vitae as Exhibit "**HB1**".

5. I joined the Applicant in 1994 as Financial Controller and was appointed Chief Financial Officer in 2006. As the Chief Financial Officer of the Applicant I have primary and direct responsibility for:

(a) financial accounting, which involves the preparation of the general accounting records, the monthly and annual financial statements, tax returns and the annual financial audit;

(b) treasury accounting, which involves (a) the management of the cash flow of the Applicant, (b) the maintenance of the relationship with lenders and compliance with financial covenants; and (c) the payments made to our suppliers;

(c) internal auditing, which involves responsibility for financial and operating audits for the Applicant; and

(d) management accounting, which involves the preparation of the accounts relating to the fixed assets of the Applicant and preparation of the annual budgets.

6. In addition, I have responsibility for:
   (a) financial reporting to the Applicant's Board of Directors and management;
   (b) preparation of the five year financial forecast;
   (c) negotiating loans to finance the Applicant's capital programme;
   (d) leading monthly meetings of management to discuss the Applicant's financial performance;
   (e) liaising with representatives of the external auditors, tax authorities, commercial banks and lenders; and
   (f) directing the efforts of the Finance Department team while ensuring their ongoing professional development.

7. I also ensure that there are appropriate internal control procedures and adherence to International Accounting Standards and International Financial Reporting Standards.

GENERALLY

8. The Applicant bases its accounts on the Federal Energy Regulatory Commission's (FERC) Uniform Systems of Accounts.

9. The Applicant's accounts are audited annually and the current Auditors are PricewaterhouseCoopers. The last audited financial statements were prepared as of December 31, 2008 ("the 2008 Financial Statements").

10. I prepared the Memoranda on Rate Base, Income Statement, Revenue Requirements and Five Year Financial Forecasts, and the supporting schedules accompanying the Memoranda found at Schedules C, D, G and L respectively of the Application for review of electricity rates ("the Application"). I had access to the Applicant's financial data which I reviewed and analysed. I also had

access to studies prepared by the Applicant's consultants and other information supplied by the management of the Applicant. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and each Memorandum are true. They form part of my written evidence in these proceedings.

11. In addition to the Memoranda described above, I also prepared the Statement of Earnings Coverage Test and the Statement of Dividends which are found at Schedules N and O of the Application respectively. These statements also form part of my written evidence in these proceedings.

12. The purpose of my evidence is to provide an overview of the matters set out in each Memorandum and the related Schedules.

MEMORANDUM ON RATE BASE

13. Rate Base is the value of utility plant financed by the Applicant and investors that is prudently incurred and "used and useful" in public service and is valued on the original or historic cost basis.

14. The Applicant sought and obtained the Fair Trading Commission's ("the Commission") permission to use historic cost for asset values in computing its rate base.

15. The Applicant's utility plant is stated at historic cost, which represents expenditures that are directly attributable to the acquisition of the plant and includes the cost of materials, direct labour, project supervision, engineering services and interest during construction. Additions to the utility plant are included in the assets carrying value or recognized as a separate asset. The Applicant uses the year-end balances for 2008 to calculate its rate base.

16. The Memorandum on Rate Base outlines the calculation of rate base as shown in Schedule C-1 of the Application and as computed for the Test Year on the 2008 Financial Statements. The Applicant has only included in the rate base plant which it has determined to be "used and useful". The Applicant's proposed rate base of $544,198,726 provides for the inclusion of cash working capital, materials, supplies, prepayment and a limited amount of construction

work in progress ("CWIP"). The accumulated provision for depreciation is deducted from the historic cost to determine net total plant. There are also deductions from rate base for funding sources other than investors, such as customer contributions for construction work not yet started and accumulated deferred income tax liability.

17. The Applicant has capitalized investment as at December 31, 2008 for all plant in service as at that date. Contributions received from customers towards construction of utility plant are credited to the cost of construction or are shown as deferred credits in those cases where construction has not yet started. Interest charges are accrued during the period of construction of property, plant and equipment and are capitalized until the asset is brought into service, at which time capitalization of interest stops and depreciation starts.

18. The Applicant's utility plant is categorized as Generating Plant assets, Transmission and Distribution assets and General Property assets. As of December 31, 2008, the cost of the utility plant in service is $937,647,461 arrived at as follows: Generating Plant - $462,652,568; Transmission and Distribution - $400,266,388; and General Property - $74,728,504. The details of these categories of utility plant are shown in the schedules attached to the Memorandum on Rate Base. Several adjustments were made to the 2008 Financial Statements in order to arrive at the Test Year figures and these are shown in Schedule C2-2.

MEMORANDUM ON INCOME STATEMENT

19. The Memorandum on Income Statement explains the Income Statement at Schedule D-1 of the Application. It records all electricity revenue (Basic and Fuel Clause Adjustment revenue) and miscellaneous income, from which the fuel expenses, operating and maintenance expenses, depreciation, finance costs and taxation are deducted to arrive at the net income. The Income Statement is based on the 2008 Financial Statements.

20. The Operating Revenue as of December 31, 2008 is $473,628,688. The operating and maintenance expenses as of December 31, 2008 are $444,484,065.

21. The Applicant's adjustments to operating income is explained in Schedule D-7. This shows that the Test Year Revenues on Existing Rates is $474,016,811 and the Operating Expenses is $440,973,147.

MEMORANDUM ON REVENUE REQUIREMENT

22. The Memorandum on Revenue Requirement details the Applicant's revenue requirement. The revenue requirement is the total amount that must be billed and collected in rates from utility customers for the utility to recover its costs and earn a fair and reasonable return. The Applicant's revenue requirement has been developed with the intent to allow it to recover its prudently incurred costs for providing utility services and to provide it with an opportunity to earn an appropriate return on invested capital including a fair and reasonable return on equity. The revenue requirement has been determined based on the following rate-making formula and its components:

    Rate Base
    x Allowed Rate of Return
    = Operating Income (required return)
    + Operating Expenses, Depreciation and Taxes
    = Revenue Requirement

23. This calculation is based on the proposed Rate Base of $544,198,726, a requested overall Rate of Return of 10.48%, Operating Income of $57,032,027 and Test Year Operating Expenses, Depreciation and Taxes of $440,973,147 on existing rates. The Test Year Operating Expenses, Depreciation and Taxes at the proposed rates is $445,206,388. The Test Year shows a revenue deficiency of $28,221,603 as set out in the Memorandum on Revenue Requirement at Schedule G-1.

MEMORANDUM ON FIVE YEAR FINANCIAL FORECASTS

24. The Applicant prepares a budget and five year financial forecast as part of its planning cycle. The financial forecast is driven by the projected growth in customer demand for electricity, the requirement for new plant and equipment to meet the growth as well as to replace plant due to be retired and assumptions regarding changes and the costs of other inputs for example labour and materials.

25. The forecast has been prepared in accordance with International Financial Reporting Standards, which are the same accounting principles used in preparing the 2008 Financial Statements. The process used to prepare the financial forecast included adequate review and approval by the Applicant's management team. In preparing its financial forecast the Applicant reviewed its Balance Sheet, Statement of Income and Statement of Cash Flows. The major assumptions used in the forecast are set out in this Memorandum at Schedule L.

26. The Five Year Financial Forecast based on existing rates shows that the Applicant's revenues would be insufficient to allow it to meet its financial obligations and earn an adequate and fair rate of return. The Five Year Financial Forecast based on the proposed rates shows that the Applicant is being given the opportunity to improve its rate of return on its earnings but will fall short of the requested rate of return during the five year period.

27. Over the next several years, the Applicant will have to access the capital markets to fund its capital expansion programme. This additional financing must be sought in a highly competitive marketplace in which many utilities and other companies will also be seeking capital and investors will have other opportunities to earn the returns they seek. The Applicant must therefore remain financially healthy if it is to attract investment at reasonable cost to continue to provide the level of service demanded of a modern utility and to fulfill its obligations to lenders, investors, customers and the public.

SWORN TO by **HUTSON R. BEST**)
At the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

Hutson Best.
HUTSON R. BEST

Before me:

Rocel

LEGAL ASSISTANT

HB1

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

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EXHIBIT "HB 1"

This is a copy of my curriculum vitae marked Exhibit "**HB 1**" mentioned and referred to in paragraph 4 of my Affidavit.

SWORN TO by **HUTSON R. BEST**)
at the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

Hutson Best
....
HUTSON R. BEST

Before me:

....
LEGAL ASSISTANT 09

HUTSON R. BEST

# 15 Seaview Road
Chancery Lane
Christ Church, BARBADOS

EXPERIENCE

Nov 1994 – Present
The Barbados Light & Power Co. Ltd.
Chief Finance Officer
- Responsible for all financial reporting to the Board of Directors and Management.
- Responsible for the annual budget and five year financial forecasts.
- Responsible for negotiating loans to finance the capital program.
- Direct the efforts of the finance department team and ongoing professional development.
- Lead monthly meetings of management to discuss the Company's performance.
- Interact with representatives of the external auditors, tax authorities, commercial banks and Lenders.
- Ensure appropriate internal control procedures and adherence to International Accounting Standards and International Financial Reporting Standards.

1991 – 1994
The Barbados Mutual Life Assurance Society (Now Sagicor)
Treasurer and Assistant Vice President of Finance
- Responsible for all financial, budgeting and regulatory reporting of the Group throughout the Caribbean.

1987 – 1990
Plantations Holdings Limited
Financial Controller
- Responsible for all financial reporting and budgeting of the group.

1983 – 1987
Ernst & Young
Audit Senior
- Supervising the audits of its large and varied clientele including hotels, banking, manufacturing and retail, wholesale and special assignments. Assisting clients with improvements to their internal controls and system reviews.

EDUCATION

1994
The University of the West Indies
MBA

1983
The Association of Chartered Certified Accountants (U.K.)
FCCA – Membership in 1983 and admitted to be a fellow in 1988

PROFESSIONAL TRAINING

2006 — **American Management Association**
Chief Financial Officer's Workshop

2003 — **University of Pennsylvania – Wharton Business School**
The CFO – Becoming a Strategic Partner

2001 — **Harvard Business School**
Driving Corporate Performance: From Scorekeeping to Strategy

1996 — **Stone & Webster Management Consultants**
Utility Management Development Program

1995 — **University of Michigan Business School**
Corporate Financial Management Program

MEMBERSHIPS

Fellow of the Institute of Chartered Accountants of Barbados
Member of the American Management Association

MK

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF MARK ST. C. KING

I MARK ST. C. KING, of #35 Mount Gardens, in the parish of St. George in this island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am the Chief Operating Officer of The Barbados Light & Power Company Limited ("the Applicant"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situate at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the facts and matters in this Affidavit and the statement of facts herein are within my personal knowledge unless otherwise stated.

EDUCATIONAL & PROFESSIONAL EXPERIENCE AND CURRENT POSITION

2. I am an Electrical Engineer by profession. I hold a Bachelor of Science degree in Electrical Engineering which I obtained from the University of the West Indies in 1976. I also hold a Master of Science in Electronics which I obtained from the University of Southampton in England in 1979. Over the course of my career, I have participated in various courses and programmes as part of my ongoing professional training, including training with US consulting firm, Stone & Webster Management Consultants and the Barbados Institute of Management and Productivity. I am a member of the Barbados Association of

Professional Engineers. A copy of my curriculum vitae is exhibited hereto as Exhibit "**MK 1**".

3. I joined the Applicant in 1976 as a trainee engineer and have been with the Applicant for over 30 years. In 1978, I resigned from the Applicant in order to pursue a Master of Science in Electronics. Upon completion of my studies in 1979, I returned to the employ of the Applicant and joined the Planning Department where I remained for a few years until I was assigned to the Distribution Department. While in the Distribution Department my duties included responsibility for construction and maintenance of substations, and the installation and management of the Supervisory Control and Data Acquisition (SCADA) system, which is used to monitor and control the entire distribution and transmission network. In 1999, I was appointed Senior Engineer of the Distribution Department where I had responsibility for the approval of all major distribution network switching, budgets, and the day to day maintenance and administration of the SCADA system. I was appointed Manager Information Systems in 2005 and in 2006 I was appointed the Chief Operating Officer of the Applicant.

4. In my capacity as Chief Operating Officer of the Applicant I have overall responsibility for the areas of generation, distribution and transmission, the purchasing section, including inventory, and the Health Safety Environmental and Quality (HSEQ) Management System.

5. The purposes of this Affidavit are principally to: (i) give an overview of the Applicant's capital expansion plans for the period 2009 - 2013; and (ii) provide general information about the Applicant's assets "used and useful" in rendering service to its customers and which are included in the rate base.

6. I prepared the Memorandum on Capital Expansion and the supporting Schedules accompanying the Memorandum found at Schedule I of the Application. In the preparation of the Memorandum I had access to the Applicant's financial and technical data, which I reviewed and analysed. I also had access to studies prepared by the Applicant's consultants and other information supplied by them. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and the Memorandum are true. They form part of my written evidence in these proceedings.

EXISTING PLANT

7. The Applicant is a vertically integrated electric utility company. It has a franchise pursuant to the **Barbados Light and Power Company (Extension of Franchise) Act,** Cap 278 of the laws of Barbados, to supply energy for all public and private purposes for a period of forty-two years from August 1, 1986.

8. As at December 31, 2008 the Applicant provided electricity service to 118,798 customers with a peak demand of 164 megawatts (MW) and had an installed capacity of 239.1MW of generating plant. Power is transmitted from the generating stations at 69,000 volts and 24,000 volts to sixteen (16) substations across the island.

9. The Applicant has included in the rate base only the plant which is currently providing or is capable of providing electricity service to its customers and which it has therefore determined to be "used and useful." Only plant prudently purchased or constructed was included in the rate base.

10. The Applicant operates a variety of generating plant including steam turbines, low speed diesel engines, and gas turbines at three generating stations (Spring Garden, Seawell and Garrison). These are listed at Table 1 of the Memorandum. The base load steam and low speed diesel units operate on residual fuel oil, (Heavy Fuel Oil (HFO), or Bunker 'C'). The gas turbines operate on diesel or aviation fuel (Jet-A1). Some natural gas is available locally and is burnt in the steam boilers, but this accounted for less than 1% of the fuel used in 2008.

11. The Applicant's oldest low speed diesel generating units were installed in 1982. The maintenance contractor and parts supplier, Burmeister & Wain Scandinavian Contractors (BWSC) has informed the Applicant that these generating units have achieved among the highest number of running hours for this type of plant anywhere in the world.

12. Between 1911 and 2000 the Applicant retired approximately 17MW of generating capacity. Between 2001 and 2008 approximately 50MW was retired. The steam turbine generators, which were installed in 1976 are now approaching the end of their economic lives. They are scheduled for retirement in 2012. This retirement would result in a reduction of approximately 40 MW of

HFO burning plant. In the forecast period, an additional 40 MW of generating capacity will therefore be retired.

13. Prior to 2000, installation of new generating capacity was driven primarily by the increase in electricity sales and peak demand. Since 2000, the replacement of generating plant which was retired has figured prominently in the Applicant's capital investment plans, resulting in the installation in 2005 of two 30MW low speed diesel generators.

Sales and Peak Demand Growth 1983 – 2008

14. Between 1983 and 2008, sales of electricity increased by an average of 4.4 % per annum while peak demand increased by 4.1 %. The average annual growth rates in sales and peak demand over the last 5 years are 3.2 % and 3.0 % respectively as shown in the following table:

YEAR	SALES	GROWTH	PEAK DEMAND	GROWTH
	GWh	%	MW	%
1983	317.4	3.2%	59.7	0.3%
1984	327.9	3.3%	61.7	3.4%
1985	334.3	2.0%	64.2	4.1%
1986	356	6.5%	67.9	5.8%
1987	388.6	9.2%	73.8	8.7%
1988	411.1	5.8%	76.1	3.1%
1989	441	7.3%	83.9	10.2%
1990	468	6.1%	87.2	3.9%
1991	486.1	3.9%	89.9	3.1%
1992	499.1	2.7%	91.5	1.8%
1993	511.9	2.6%	93.9	2.6%
1994	529.1	3.4%	97.6	3.9%
1995	566.3	7.0%	104.2	6.8%
1996	591.5	4.4%	109.8	5.4%
1997	620.5	4.9%	113.3	3.2%
1998	657.8	6.0%	117.7	3.9%
1999	676.8	2.9%	123.2	4.7%
2000	704	4.0%	124.85	1.3%

YEAR	SALES	GROWTH	PEAK DEMAND	GROWTH
2001	737.1	4.7%	130.5	4.5%
2002	766.1	3.9%	134.7	3.2%
2003	805.9	5.2%	141.6	5.1%
2004	831.3	3.2%	143	1.0%
2005	884.7	6.4%	154.2	7.8%
2006	903.4	2.1%	157	1.8%
2007	940.8	4.1%	162.4	3.4%
2008	944.0	0.3%	164.0	1.0 %
Average 1983 – 2008		4.4%		4.1%
Average 2004 - 2008		3.2%		3.0%

SYSTEM EXPANSION

15. As part of its planning process, the Applicant in 2004 retained PB Power Ltd., electrical utility consultants based in the UK, to prepare a Generation Expansion Study (the 2005 Study) which would take account of the likely availability of large volumes of natural gas from Trinidad & Tobago and the power which would result from the wind power project, referred to later in this Affidavit. A copy of the 2005 Study was made available at the Depreciation Hearing held before the Fair Trading Commission in January 2009.

Planning Criteria

16. The need for new generating plant is based on maintaining an acceptable level of reliability. The goal of the Applicant's expansion plan is to determine the least-cost solution required to provide electricity service which meets the specified levels of reliability. The Applicant's aim is to achieve the right balance between cost and system reliability. A more reliable system can be achieved with more plant, but at increased cost. The Applicant uses loss-of-load probability (LoLP) as its main planning criteria for generation reliability.

17. The following input data were used to determine the need for and type of new generating plant to be purchased:
    - Target levels of system reliability.
    - Electricity sales projections.
    - Expected growth in electricity peak demand.
    - System load factor.
    - The existing generating plant types and the options available for new plant (candidate plant).
    - Proposed retirement schedule for existing plant.
    - Availability, reliability, fuel type and efficiency of existing and candidate plant.
    - Estimated capital cost of candidate plant.
    - *Operating and Maintenance (O&M) cost of existing and candidate* plant.
    - Price projections for the different fuel types.

18. A measure of the reliability of a transmission system is its ability to satisfy the N-1 *criterion (that is, the system remains stable and within continuous rating for* the outage of any one circuit).

19. In July 2007 the Applicant instructed PB Power Ltd to update the 2005 Study to assist the Applicant in developing a generation and transmission expansion plan for the period 2008 - 2027 with the clear objective of achieving the dual goals of least-cost and target levels of system reliability (the 2008 Study). To achieve this, PB Power was required to update the previous scenarios which were produced using (a) liquid fuel and (b) natural gas as the base fuel. To each scenario, the options of wind and bagasse power were added individually and collectively. Finally, all of the above scenarios were subjected to sensitivity analysis by varying the projected sales growth of the Applicant above and below the base case.

20. For the purposes of the 2008 Study, the key planning criteria were:

    - A study horizon of 20 years with detailed network analysis for the first 10 years (2008 – 2017).
    - A generation reliability of 1 day/year LoLP.
    - A maximum allowable individual generating unit size of 20% of the projected peak demand.

- N -1 planning criteria for the transmission network to ensure full system operation following a loss of a cable or transformer.
- Electricity sales growth scenarios of 2%, 4% and 6%.

Sales Growth Projections

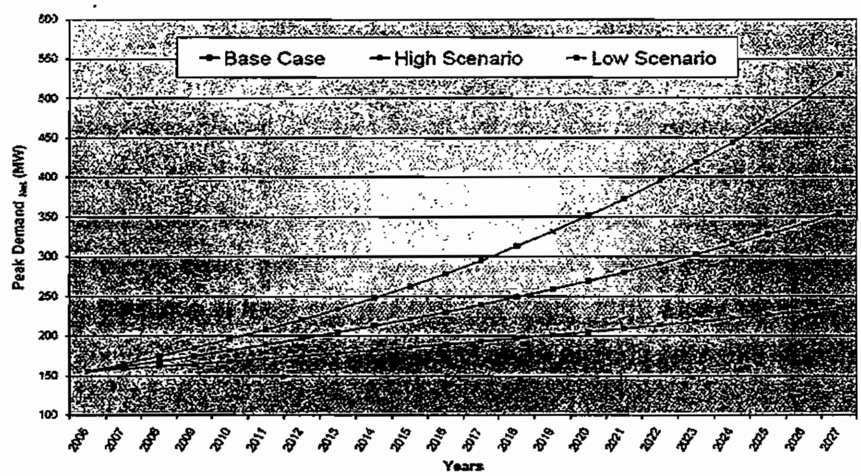
21. For the purposes of the 2008 Study the Applicant selected three sales growth scenarios, namely:

    (a) A base case scenario of 4% annually.

    (b) High growth scenario of 6% annually.

    (c) Low growth scenario of 2% annually.

22. These scenarios are shown in the figure below.



Expansion Plan Decision

23. The 2008 Study analyzed three possible plant types – low speed diesels, medium speed diesels and gas turbines. It showed that for an oil-based scenario the least cost option would be low speed diesels, followed by medium speed diesels with gas turbines being the most costly. On the other hand, if natural gas is available the least cost option would be gas turbines and then medium speed diesels. The most costly would then be low speed diesels. Medium speed diesel engines are capable of operating on either HFO or natural gas in dual-fired configuration.

24. In view of the uncertainty concerning the availability of natural gas, it was decided that the prudent choice for the Applicant would be medium speed diesels. Although this is not the least cost option as recommended in the 2008 Study, it protects against the risk of having to select an option which might turn out to be the most costly.

25. In this scenario should natural gas arrive within the five to ten year horizon there should be very little additional cost for conversion; hence medium speed diesels have been used in the preparation of the capital expansion plan.

26. Recent uncertainty over the future of oil prices and the projected slowdown in world economies suggest that the most likely near term scenario is one of low load growth. Further analysis, as detailed in the Memorandum on Sales Projections, shown at Schedule H, also supports this lower projected growth. The five year expansion plan presented in the Memorandum on Capital Expansion is therefore based on the low load growth scenario.

27. The system expansion plan for the liquid fuel 2% growth case was therefore remodeled by the Applicant using the most recent sales projections, and updated five-year averages for system losses and load factor. In the Memorandum on Sales Projections a slightly higher sales growth of 2.5% is projected for years 2011, 2012 and 2013. If this level is achieved this will not materially affect the choices made in the expansion program.

28. The option selected, which involves the installation of medium speed diesel engines, is shown in the following Table.

Proposed Liquid Fuel Expansion Plan

	2007	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**
Sales (GWh)	940.8	944	963	982	1002	1022	1042
Demand (MW_{Net})	159	164	167	170	174	177	181
New Capacity	-	-		-		D16 16MW	D17,D18 32MW
Retirements (Dec 31)	-	-	-	-	-	S1& S2 (40MW)	

Generation Expansion

Major Capital Projects

29. The Applicant is proposing to undertake several major generation projects. The details of these projects are shown in Schedule I-1. Among them are the following:

    (a) **Diesel Generating Plant** –The expansion plan calls for the commissioning of one 16 MW Diesel Generating Plant in 2012 if the Applicant is to maintain the level of reliability already established. It is expected that the tendering process for the purchasing of this unit will be implemented in 2010 and a contract awarded for the installation of the unit. This plan also calls for the commissioning of two (2) additional 16 MW Diesel Generating units in 2013 since the existing steam generating units are scheduled to be retired at the end of 2012.

    (b) **Trents Site Development** – The new generating units will be installed at the Trents site in St. Lucy.

    (c) **Fuel Pipeline** – The projected generation expansion is based on the installation of diesel generating plant capable of burning liquid fuel and natural gas. The Applicant plans to establish a bunkering facility on a portion of its property at Checker Hall, St. Lucy and to install a pipeline from there to Trents.

    (d) **10 MW Wind Farm at Lamberts** – The Applicant has considered various renewable energy options as part of its capital expansion plans, some of which are more feasible than others. These include biomass, wind power, solar photovoltaics, waste-to-energy, and landfill gas. Wind power appears to be the most economically viable. The Applicant continues to work towards the establishment of a Wind Farm at Lamberts, St. Lucy. If a favourable decision is rendered on the Applicant's planning application for a Wind Farm the Applicant intends to commence work on the project in 2010. Based on information currently available on similar units, it is expected that the units will be available for commissioning in 2011.

(e) **Ash Handling** –This project which will to be implemented in 2009 requires the upgrading of the existing ash handling system at Spring Garden to reduce the negative effects of residual ash generated as a result of fuel burnt in the new Low Speed Diesel station.

(f) **Fire Protection System** - A new fire protection system will be installed at the Seawell generating site.

(g) **Alternative Cooling Water System** – The Applicant proposes to install in 2009 an alternative Cooling Water System for the new Low Speed Diesel station.

Transmission and Distribution Expansion

Overview

30. The Applicant also instructed PB Power to examine the transmission infrastructure, with particular emphasis on the central and northern areas and taking into account the projected growth, the possible location of that growth, and the decision to establish a new generating site in the north of the island. This new site would quickly become the Applicant's main generating site if imported natural gas becomes available. The transmission network will be designed to be sufficiently resilient to withstand an extended outage on any one line.

31. The establishment of a major generating site at Trents in St. Lucy requires the installation of significant Transmission and Substation infrastructure in the north of the island, so as to ensure that the power generated there can be adequately and reliably dispatched.

32. In the interest of enhanced reliability, security and reduced maintenance costs, the Applicant has decided that new transmission lines will be placed underground.

33. Work commenced on a 132 kV double circuit underground transmission line from the Applicant's substation located opposite the St. Thomas Church to Trents in St. Lucy in 2006. Initially, the transmission lines will be operated at 24kV. As more generation is added at Trents these will be upgraded to 132kV.

It was deemed appropriate to install cables at this time and make them suitable for operation at the higher voltage since it was considered that if they were to be installed at a later time there would be greater expense with installing them underground and also difficulty in obtaining adequate rights of way.

34. To cater to the projected growth in the north of the island, it was necessary to build a substation at Upper Carlton in St. James (Carlton) and upgrade the existing substation at Maynards in St. Peter (North). 24kV transmission cables linking St. Thomas to Carlton and North substations have been commissioned.

Major Capital Projects

35. The Applicant is proposing to undertake several major projects for expanding, improving and upgrading the transmission and distribution system. Schedule I-2 details these projects among which are the following:

(a) the building of a 132 kV transmission line between St. Thomas and Trents;

(b) the building of other transmission circuits;

(c) the upgrading and enhancement of aspects of the distribution network; and

(d) the expansion of various substations including Carlton, Belmont, Wotton, St. Thomas and Trents.

General Property

36. The Applicant proposes to introduce a number of systems to enhance the operation of the business. The Applicant's hardware and software infrastructure will need to be upgraded to accommodate these applications. These are set out in Schedule I-3.

CONCLUSION

37. The cost of fuel used in the generation of electricity is the single largest component of the Applicant's operating expenses. Uncertainty over the future of oil prices and the possible availability of an alternative fuel in the form of natural gas have influenced the decision making process. Generation of electricity in sufficient quantities to adequately satisfy the needs of the island, in the short term, can only be achieved by burning fossil fuels. The Applicant has therefore chosen to install Medium Speed Diesels for future expansion primarily because these units will provide the greatest flexibility in the use of fuel. In the immediate future, the Applicant will burn HFO but the Medium Speed Diesels can be easily reconfigured to burn natural gas if and when this should become available.

38. The introduction of a new generating site at Trents requires that the transmission network linking that area to the grid be significantly enhanced. To this end two (2) 132kV underground transmission lines will be installed between Trents and St. Thomas. These will be supplemented by 24 kV transmission lines from St. Thomas to North and Trents via the new Carlton substation. The introduction of the wind farm will also require the construction of a new 24 kV transmission line from the site of the farm to Trents. In the south of the island work will be required to upgrade aging substations and replace older switchgear and protective devices.

39. To better serve its customers and improve its business processes, the Applicant will be upgrading its IT infrastructure.

40. The Applicant recognized the need to diversify its fuel supply and has proposed the introduction of a 10 MW Wind farm to its grid. The Applicant is also interested in the proposed fuel cane and waste-to-energy projects. The latter two of these renewable resources have the potential to defer the installation of oil burning plant.

41. There is considerable interest surrounding solar photovoltaics and micro wind turbines for individual use. The Applicant has collected several years of experience and data on PV systems and will be reviewing and expanding its involvement with these systems in the future. The Applicant will facilitate the grid-connection of customer owned renewable energy systems through the

establishment of a technical interconnection standard and is applying for a tariff for those customers who provide excess energy to the grid.

SWORN TO by **MARK ST.C. KING**)
at the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

....
MARK ST.C. KING

Before me:

....
LEGAL ASSISTANT

MK1

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

EXHIBIT "MK 1"

This is a copy of my curriculum vitae marked Exhibit "**MK 1**" mentioned and referred to in paragraph 2 of my Affidavit.

SWORN TO by **MARK ST. C. KING**)
At the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

....
MARK ST. C. KING

Before me:

....
LEGAL ASSISTANT

MARK ST. C. KING

35 Mount Gardens
St. George, BARBADOS

EXPERIENCE

Oct 2006 – Present **The Barbados Light & Power Co. Ltd.**
Chief Operating Officer

Jan 2005 – Sep 2006 **The Barbados Light & Power Co. Ltd.**
Manager Information Systems

June 2001- Dec 2005 **The Barbados Light & Power Co. Ltd.**
Project Manager - New SCADA system
Senior Engineer - Technical section Distribution Department.

SCADA

- Responsible for directing a cross-functional team in the definition of the Company's requirements for the SCADA system.
- Approved, on the Company's behalf, the selection of the Vendor
- Represented the Company at all negotiations with prospective Vendors.
- Conducted and approved Factory Acceptance Tests
- Supervised the installation and site acceptance testing of the system.
- System Administrator.

Technical Section

- Direct responsibility for the performance of one Engineer and one Assistant Superintendent.
- Responsible for the approval of all major Distribution Network switching
- Approval of all Budgets for the Section
- Assist Substation engineer in daily duties -primarily technical in nature.
- Coordinates the installation and commissioning of all substation switchgear
- Responsible for the day-to-day maintenance and administration of the SCADA system
- Responsible for the entire VHF/UHF Communication Network.

June 1999 - June 2001 **The Barbados Light & Power Co. Ltd.**
Project Manager PSMax

- Effectively Managed team of 20 employees and Consultants during the installation of the applications
- Developed terms of reference for Consultants for this project.
- Managed the selection of the consultants
- Managed the selection of the Applications
- Assumed full responsibility for day to day requirements of the entire team
- Reported to the Steering Committee of Senior Managers
- Drafted and presented a successful cost benefit analysis of the project
- Prepared and managed the entire budget for the Project.

March 1984 - June 1999 **The Barbados Light & Power Co. Ltd.**
Senior Engineer - Technical Section Distribution Department.

- Direct responsibility for the performance of one Engineer and one Assistant Superintendent. A total of 43 persons in the Section.
- Assisted in the development and installation of the Company's Switching and Tagging Procedures.
- Developed Trouble Call analysis and reporting system, which reduced the delivery of the daily log book from days to minutes.
- Responsible for the approval of all major Distribution Network switching
- Approval of all Budgets for the Section
- Assist Substation engineer in daily duties -primarily technical in nature.
- Responsible for the day-to-day maintenance and administration of the SCADA system
- Responsible for the entire VHF/UHF Communication Network.

EDUCATION

1999 **Strategic Information Services**
Project Management Training Certificate

1993 **Stone & Webster**
Utility management development program Certificate.

1989-1981 **Barbados Institute of Management and Productivity Certificates**
Accounting and Finance for Managers
Economics for Managers
Management of Human Resources

1979 **University of Southampton** , Southampton, England
Master of Science- Electronics
Awarded the Commonwealth Scholarship in 1978

Designed and built microprocessor based In Circuit Emulator for testing and debugging microprocessor based systems where conventional test equipment would be useless.

1976 **University of the West Indies,** St. Augustine Trinidad
Bachelor of Science- Electrical Engineering
Awarded the Aubrey Collymore Scholarship in 1973
Achieved Upper class Honors

MEMBERSHIPS

Member, Institute of Electrical & Electronic Engineers (IEEE), U.S.A.
Member of the Barbados Association of Professional Engineers
Member of the Amateur Radio Society of Barbados

SW

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF STEPHEN T. WORME

I STEPHEN T. WORME, of #4 Rockley Meadows, Golf Club Road, in the parish of Christ Church in this island, being duly sworn hereby **MAKE OATH** and say as follows:

1. I am the Chief Marketing Officer of The Barbados Light & Power Company Limited ("the Applicant"), a company registered under the Companies Act, Chapter 308 of the Laws of Barbados with its registered office situate at Garrison Hill in the parish of St. Michael. I am duly authorized to depose to the facts and matters in this Affidavit and the statement of facts herein are within my personal knowledge unless otherwise stated.

EDUCATIONAL & PROFESSIONAL EXPERIENCE AND CURRENT POSITION

2. I am an Electrical Engineer by profession. I hold a Bachelor of Engineering Science degree from the University of Western Ontario, Canada and a Master of Business Administration from the University of the West Indies. A copy of my curriculum vitae is exhibited hereto and marked as Exhibit "**SW 1**".

3. I joined the Applicant in 1979 and have been with the Applicant for over 29 years. I joined the Applicant as a trainee distribution engineer and in 1980 I

resigned in order to work with Fisher Hess in St. Lucia as an Electrical Engineer. I resumed employment with the Applicant in 1981 as a Distribution Engineer in the Distribution Department where I remained for a few years until I was assigned to the Commercial Department (now known as the Customer Services Department) as Commercial Superintendent where I was responsible for the functions of the commercial department, billing of electricity accounts, collection of all payments, customer service and service inspections. In 1988, I was appointed Customer Services Manager where I was actively involved in the implementation of the Applicant's Total Quality Process. In 2003, I was appointed Manager of Marketing and Corporate Communications with responsibility for establishing and developing relationships with key customers and managing the external and internal communications of the Applicant. *In 2006, I was appointed the Chief* Marketing Officer of the Applicant.

4. I am a former First Vice President of the Barbados Manufacturers' Association.

5. I am a registered professional engineer in Barbados, a member and past Treasurer of the Barbados Association of Professional Engineers, a member of the Institute of Electrical and Electronic Engineers Inc. (IEEE) of the United States of America and a member of the International Association of Business Communicators (IABC).

6. In my capacity as Chief Marketing Officer of the Applicant I have overall responsibility for the areas of customer service, marketing and corporate communications.

7. I have prepared the Memoranda on Sales Projections, Proposed Tariffs and Service Standards, and the supporting schedules accompanying the Memoranda, which are found at Schedules H, K and M of the application for a review of electricity rates by the Applicant ("the Application"). In the preparation of the Memoranda I had access to the Applicant's financial and technical data. I also had access to studies prepared by the Applicant's consultants and other information supplied by them and the management of the Applicant. To the best of my knowledge, information and belief, the facts and matters set out in this Affidavit and each Memorandum are true. They form part of my written evidence in these proceedings.

8. The purpose of my evidence is to provide an overview of the matters set out in each Memorandum and the related Schedules.

MEMORANDUM ON SALES PROJECTIONS

9. This Memorandum sets out the sales projections for the period 2009 to 2013. The Applicant used three (3) forecasting methods in developing the electricity sales projections for this period. The first is an econometric model that uses historical energy sales. With this model, forecast estimates are obtained for the four main tariff groups namely, Domestic Service, General Service, Secondary Voltage Power and Large Power. These estimates are then combined to derive an aggregated forecast. The second method is an econometric model that uses historical net generation data. With this model the resulting estimates for net generation are converted to energy sales. The key forecast driver for these two models was Gross Domestic Product (GDP). Finally, a simple trend analysis of historical electricity sales from 1960 to 2008 was extrapolated for the future period 2009 to 2013. The information from the foregoing methodologies together with information gathered from Government sources and agencies, the Central Bank of Barbados, property developers, among others were used to make the sales projections. The Applicant also relied on its many years of experience in determining what it considers to be reasonable projections.

10. The Models used in the analysis suggested different growth rates. The first method forecasted growth ranging from -0.1% to 1.0%. The second method forecasted growth ranging from 0.6% to 1.4%. The simple trend analysis suggested growth ranging from 2.5% to 3%. After taking all of these factors into consideration, the Applicant has thought it to be prudent, for the purposes of the Application, to adopt more optimistic projections than some of the data suggests and proposes sales growth rates of 2% for the first two years of the projected period and growth rates of 2.5% in the latter three years.

MEMORANDUM ON PROPOSED TARIFFS

11. The purpose of this Memorandum is to present the electricity rates that are being proposed by the Applicant and the rationale for the rate design. In order to determine the Applicant's proposed tariffs, the Applicant established

a rate design team drawn from the Customer Services, Distribution, Information Systems, and Marketing & Corporate Communications departments. I was responsible for supervising the work of this team.

12. The rate design process which was applied by the rate design team was as follows:

 (a) The first step in the rate design process was to review the existing tariffs and examine the adequacy of the current rates and rate structure.

 (b) The Applicant also reviewed the tariffs and tariff trends in the industry and met with different groups of customers, including some of its key account customers, self-generators, residential customers and those interested in the use of renewable resources in order to obtain feedback on a rate adjustment and to determine their rate needs. Information was also obtained from discussions with Government representatives on several of the issues being considered.

 (c) After consideration of the issues, the specific objectives of the rate design were set with the assistance of an embedded cost-of-service study and, through an iterative process, new rates and rate structures were developed and their impact on the different groups of customers examined. The impact was further investigated with representatives from some customer groups before the designs were finalised.

13. The main objectives of the rate design were to:

 (a) raise additional revenue of $28.2 million to meet the revenue requirements as set out in the Memorandum on Revenue Requirement which is found at Schedule G of the Application, and to produce a Rate of Return of 10.48% as set out in the Memorandum on the Rate of Return which is found at Schedule F of the Application.

 (b) provide fair rates and to apportion the total cost of service among the different classes of customers in a fair manner, sensitive to any impact on customers.

(c) encourage customers to use the electricity more efficiently by:

i. revising the existing rates to more closely reflect the unit cost of serving customers, thereby reducing the inter and intra class subsidies that presently exist;

ii. providing rates with an inclining block rate structure in the Domestic Service, General Service and Employee tariffs;

iii. introducing a Time-of-Use tariff on a pilot basis for customers who qualify under the Large Power tariff; and

iv. introducing an Interruptible Service Rider on a pilot basis for customers who have flexibility in their usage of electricity or who have standby capacity and who qualify under the Secondary Voltage Power and Large Power tariffs.

(d) encourage the use of customer-owned renewable energy sources by introducing a Renewable Energy Rider on a pilot basis for customers in all tariffs, which allows customers to use grid-tied renewable energy sources and to sell any excess energy into the electricity grid;

(e) shift the 2.64 cents per kWh of fuel cost from the base energy rate to the Fuel Clause Adjustment ("FCA") as recommended in the "Fuel Adjustment Charge Findings Report"[1] by the Fair Trading Commission ("the Commission") so that the full fuel cost is collected through the FCA;

(f) revise the Service Charges to more closely reflect the cost of service; and

(g) lessen the rate impact of the overall revenue increase on customers in the lower income bracket.

14. The existing tariffs, Fuel Clause and Service Charges are found at Schedules J-1 to J-8 of the Application. The tariffs are Domestic Service (DS), General

[1] Fuel Adjustment Charge Findings Report by the Fair Trading Commission, 19 January 2007 – Document No. FTC/URD/FACREP/0107

Service (GS), Employee (EMP), Secondary Voltage Power (SVP) Large Power (LP) and Street Lighting (SL). DS, GS, EMP, SVP, LP and SL, are subject to the FCA, which is found at Schedule J-6.

15. As part of the rate design, an Embedded Cost of Service Study ("the COS Study') was carried out by Christensen Associates Energy Consulting LLC (CAEC). A copy of the embedded COS Study report is attached to the Affidavit of Michael O'Sheasy of CAEC. The rate design team worked closely with Mr. O'Sheasy to prepare the rate design.

16. The Applicant in its design process began with the proposed revenue requirement for the COS Study as its revenue layout for the new rate designs. The Applicant also considered the unit cost results of the COS Study by rate in order to guide its rate component prices.

17. The COS Study identified the following:

Table 1.

	Realised Return	Rate of Return (ROR)
i) Overall	$33,053,648	6.07%
ii) Domestic Service[2]*	$4,146,009	2.58%
iii) General Service	$1,517,226	4.02%
iv) Secondary Voltage Power	$13,822,475	6.12%
v) Large Power	$13,956,153	12.40%
vi) Streetlights	($388,214)	-5.42%

18. As can be seen from Table 1, the overall Rate of Return on Rate Base from the COS Study is 6.07% with the contribution from the tariff groups varying from 2.58% to 12.40%, except for streetlights which was -5.42%. The overall rate of return for the Test Year 2008 is significantly lower than the 10.48% requested by the Applicant.

19. The ideal objective would be to achieve full parity for all tariffs, that is, each tariff would be targeted to achieve the same rate of return as the overall rate of return of 10.48%. However, the Applicant has calculated that this would result in a substantial increase in electricity costs for some customers. The

[2] Includes EMP which only makes up 0.2% of overall kWh sales

likely rate shock could pose significant hardship for these customers, particularly residential customers in the lower income bracket. Consequently, the Applicant has not chosen this option at this time.

20. The Applicant proposes to revise and seek an increase in electricity rates for all existing tariffs. It also proposes to implement a new Time of Use Tariff, an Interruptible Rider and a Renewable Energy Rider, all on a pilot basis. The Applicant also proposes to revise the Fuel Clause and the Service Charges. The Applicant wishes to encourage energy saving and conservation amongst its customers. As such it proposes to maintain an inclining block rate structure in the DS tariff category and to introduce this in the GS and EMP tariff categories. It is also proposed that the full fuel cost be recovered through the FCA. The proposed tariffs, riders, FCA and Service Charges are shown in Schedules K-1 to K-11.

21. The proposed tariffs are made up of two or more of the following four components, as appropriate: (i) the customer charge, (ii) the demand charge, (iii) the base energy charge, and (iv) the fuel charge. The Applicant proposes that the following rates of return be achieved from the existing tariff categories:

(a) **Domestic Service** - 7.82%. This will require $9.7 million in additional sales revenue, an increase of 16.99% in basic revenue. It is proposed that the revenue be collected through a customer charge with an inclining block rate, a base energy charge also with an inclining block rate to encourage energy conservation and a fuel charge.

(b) **Employees** - The rate of return for employees is included in the rate of return for DS. It is proposed that the revenue be collected through a base energy charge with an inclining block rate to encourage energy conservation and a fuel charge.

(c) **General Service** - 9.00%. This will require $2.2 million in additional sales revenue, an increase of 17.03% in basic revenue. It is proposed that the revenue be collected through a customer charge with an inclining block rate, and a base energy charge also with an inclining block rate to encourage energy conservation and a fuel charge.

(d) **Secondary Voltage Power** - 10.99%. This will require $12.9 million in additional sales revenue, an increase of 16.69% in basic revenue. To achieve this it is being proposed that the revenue be collected through a customer charge, a demand charge, and a base energy charge (at a flat rate) and a fuel charge

(e) **Large Power** - 14.42%. This will require $2.7 million in additional sales revenue, an increase of 5.47% in basic revenue. To achieve this it is proposed that the revenue be collected through a customer charge, a demand charge and a base energy charge (at a flat rate) and a fuel charge

(f) **Street Lights** - 0.00%. This will require $456,722 in additional sales revenue, which is an increase of 20.42% in basic revenue. Since street lights are not metered, it is proposed that the total revenue be collected, as at present, through a single charge, the Customer Charge to recover the customer, demand and energy related cost and a fuel charge.

22. The Applicant proposes a new Time-of-Use Tariff on a pilot basis for a period of three (3) years for customers who qualify under the LP tariff. This tariff is designed to reflect the fact that a utility's cost of providing electricity vary depending upon the time of day. The Applicant incurs its highest cost between the hours of 10.00 a.m. and 9.00 p.m. weekdays (except public holidays). It is during this time that peaking plants, which have higher operating costs, are needed. This period is defined as 'Peak', with all other periods being 'Off-Peak'. Time-of-Use rates are designed to reduce 'Peak' demand. It is proposed that there be a monthly customer charge, a demand charge, a base energy charge, and a fuel charge. The base energy charge and the fuel charge will be priced differently for 'Peak' and 'Off-Peak' periods.

23. The Applicant proposes two riders, an Interruptible Service Rider and a Renewable Energy Rider. It is proposed to introduce on a pilot basis, for a period of three (3) years, an Interruptible Service Rider which will be available to SVP and LP customers who have flexibility in their use of electricity, a minimum billing demand of 300 kVA, and a minimum monthly interruptible demand of 100 kVA. Interruptible loads provide the Applicant with the opportunity to reduce the overall demand on the system. As long as the interruptible demand can be relied upon, it is expected that the Applicant will be able to reduce its investment in the long term. This benefit can be passed

on to the customers with interruptible loads through a capacity credit. This credit has been guided by a marginal cost analysis.

24. The Applicant continues to look for opportunities to diversify its fuel mix. One opportunity is to purchase energy from customers who produce it for their own use from photovoltaic, wind or other renewable sources and have excess energy to sell to the grid. The Applicant therefore proposes to introduce a Renewable Energy Rider initially on a pilot basis for three (3) years to give the Applicant an opportunity to determine the technical and economic impacts of this programme. This proposed rider will provide a credit to the customer's bill based on the amount of energy supplied to the grid and will also be used to off-set bills. Any net credit resulting at the end of the calendar year will be refundable.

25. It is the Applicant's view that the proposed rate designs fairly and reasonably reflect the objectives that guided the rate design. The Applicant therefore respectfully requests that the proposed tariffs, riders, FCA and service charges be approved.

STANDARDS OF SERVICE

26. As part of the Application, the Applicant submits its proposal for Standards of Service as outlined in the Memorandum on Standards of Service at Schedule M.

27. There is a close connection between rates and service standards and this is recognized in the **Utilities Regulation Act,** Cap 282 of the laws of Barbados. On February 28, 2006 the Commission issued its Decision on Standards of Service for the Applicant. This is shown in Schedule M-1. These Standards of Service came into effect on June 1, 2006 and included Guaranteed Standards of Service and Overall Standards of Service.

28. On November 27, 2007 the Commission issued its Standards of Service Report on the Performance of the Applicant for the period June 1, 2006 to May 31, 2007. This is found at Schedule M-2 of the Application.

29. On October 29, 2008 the Commission issued a Consultation Paper entitled *"Review of The Barbados Light & Power Company Ltd. Standards of Service"*,

("the Consultation Paper") which included results referenced in Schedule M-2, plus results for the period up to May 31, 2008. This is found at Schedule M-3 of the Application.

30. The results for the Standards of Service as prepared by the Applicant for the reporting period April 1, 2008 to March 31, 2009 as recently submitted to the Commission is found at Schedule M-4 of the Application. The Applicant conducts regular surveys to better understand its customers' needs and continues to seek ways in which it can improve its operations and quality of service. The implementation of Standards of Service has been a positive influence in this regard.

31. In response to the Consultation Paper, the Applicant on November 26, 2008 submitted its comments to the Commission. The Applicant's submission is included at Schedule M-5 of the Application.

32. Up to the time of submission of the Application, the Commission had not issued a decision on the revised Standards of Service for the Applicant. Until such time as the Commission decides on revised Standards of Service, the Applicant proposes that the existing Standards of Service remain. The Applicant considers these Standards of Service to be consistent with the electricity rates being applied for in its Application.

SWORN TO by **STEPHEN T. WORME**)
at the Law Courts, Coleridge Street, Bridgetown)
this 6th day of May 2009)

STEPHEN T. WORME

Before me:

LEGAL ASSISTANT

SW1

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

EXHIBIT "SW 1"

This is a copy of my curriculum vitae marked Exhibit "**SW 1**" mentioned and referred to in paragraph 2 of my Affidavit.

SWORN TO by **STEPHEN T. WORME**)	....
At the Law Courts, Coleridge Street, Bridgetown)	**STEPHEN T. WORME**
this 6th day of May 2009)	

Before me:

....

LEGAL ASSISTANT

STEPHEN T. WORME

4 Rockley Meadows
Golf Club Road
Christ Church, BARBADOS

EXPERIENCE

Oct 2000 – Present
The Barbados Light & Power Co. Ltd.
Chief Marketing Officer
- Overall responsibility for the Customer Service, Marketing and Corporate Communications functions in the Company.

August 2003 – Oct 2006
The Barbados Light & Power Co. Ltd.
Manager Marketing and Corporate Communications
- Responsible for establishing and developing key relationships with key customers and managing the external and internal communications in the Company.

Jan 1988 – July 2003
The Barbados Light & Power Co. Ltd.
Customer Services Manager
- The Commercial Department was renamed the Customer Services Department in 1988. Besides being responsible for the operations of the Department, I was actively involved in the implementation of the Total Quality Process in the Company from June 1990.

July 1985 – Jan 1988
The Barbados Light & Power Co. Ltd.
Commercial Superintendent
- Responsible for the functions of the Commercial Department, which included billing of electricity accounts, collecting of all payments, customer service, service inspections etc.

July 1981 – July 1985
The Barbados Light & Power Co. Ltd.
Distribution Engineer
- Responsible for the construction and maintenance of substations. This included two major projects: the construction of the St Thomas Substation and the extension of the Temple Yard Substation.
- Involved in the design and implementation of Supervisory Control and Data Acquisition (SCADA) System used to operate and monitor equipment at Distribution Substations throughout the island. This was implemented in March 1985.

Jan 1981 – July 1981
Fisher Hess, St. Lucia
Electrical Engineer
- Assisting with the maintenance of electrical appliances, generation equipment, installation of street lights on construction site for oil terminal in St Lucia.

July 1979 – Dec 1980
The Barbados Light & Power Co. Ltd.
Trainee Distribution Engineer
- Responsible for the maintenance and installation of transformers, cables, streetlights, under frequency system etc.

EDUCATION

1995 **The University of the West Indies**
MBA (Masters of Business Administration)
Selected as Class Valedictorian after receiving distinctions in all 16 courses completed in the programme.

1979 **University of Western Ontario,** Canada
BESc (Bachelor of Engineering Science)

1975 **Barbados Community College**
Barbados Exhibition for achievement in Advanced Level Examinations

MEMBERSHIPS

Member & former Treasurer, Barbados Association of Professional Engineers
Member, Institute of Electrical & Electronic Engineers (IEEE), U.S.A.
International Association of Business Communicators (IABC), U.S.A

ACTIVITIES

President of Ursuline Schools Parent Teachers' Association
(1999 to 2001)
Member of Ursuline Schools Parent Teachers' Association
(Immediate Past President – 2001 to 2003)
2nd Vice President Barbados Manufacturers Association
(2005 to 2006)
1st Vice President Barbados Manufacturers Association
(2006 to 2007)
Director of Goddard Enterprises Limited
(2005 to Present)
Chairman of Research Circle for National Initiative for Service Excellence (NISE – 2005 to present)

SPECIAL INTERESTS

With the limited alternatives available for the education of boys in the secondary school system in Barbados, I have worked with a committee of businessmen and educators to investigate the opening of a private secondary school for boys.

RC

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF ROBERT J. CAMFIELD OF
CHRISTENSEN ASSOCIATES ENERGY CONSULTING, LLC
CONCERNING THE COST OF CAPITAL OF
THE BARBADOS LIGHT & POWER COMPANY LIMITED

I, **ROBERT J. CAMFIELD**, being duly sworn, make oath and say as follows:

1. I am a Vice President at Christensen Associates Energy Consulting, LLC, (CAEC) an economic research and consulting group and for the purposes of these proceedings my address is in care of Christensen Associates Energy Consulting, LLC 4610 University Ave., Suite 700 Madison, Wisconsin 53705, United States of America. I am duly authorized to swear to this Affidavit.

2. CAEC is a wholly owned subsidiary of Laurits R. Christensen Associates (Christensen Associates) and has been providing consulting services to the energy industry for over 30 years. Our consulting group provides a full range of services including retail planning and pricing, survey research and analysis, power engineering and network economics, transmission and distribution,

asset valuation, resource strategy, market design, regulatory support, expert testimony, and litigation support. CAEC serves large and small private firms and organizations across the United States and around the world, including investor-owned utilities, public power, cooperatives, regulatory agencies, transmission companies, regional transmission organizations, generation companies, commodity traders, and law firms. Our clients include Georgia Power Company, California Energy Commission, East Kentucky Power Cooperative, Ontario Energy Board, Wisconsin Energy, Polish Power Grid Company, and the Jamaica Public Service Company Ltd.

I. EDUCATIONAL AND PROFESSIONAL EXPERIENCE

3. I hold a Masters degree in economics from Western Michigan University, and I am a graduate of Interlochen Arts Academy.

4. The scope of my professional work includes capital valuation, economic cost assessment, regulatory economics and governance, and wholesale contracts and negotiation. My experience covers a number of issues facing regulated industries, with a concentration in electricity services. I have testified on the cost of capital and provided rate of return recommendations on behalf of private companies and utility associations. I have also testified in regulatory proceedings on behalf of consumer advocacy groups, transmission and distribution companies, integrated electric utilities, regulatory agencies, and utility associations. I have provided evidence, analysis, and testimony on a variety of topics including power supply contracts, transmission congestion, marginal costs and cost allocation, tariff design and rate phase-in plans, and regulatory policy regarding transmission grid investment, corporate performance and cost benchmarking, generation supply plans, and load and energy forecasts.

5. My assignments with our clients include a large electricity market restructuring project in Central Europe. In the Caribbean region, I was involved in the franchise license of Mirant Corporation and its purchase of Jamaica Public Service Company Limited. I have initiated or been involved in several innovations including two-part tariffs for transmission services, web-based self-designing retail electric products, marginal cost-based cost-of-service methods, and principles for efficient pricing of distribution services.

6. I have published chapters in technical books, reports, and articles in noted journals such as *The Electricity Journal, IEEE Transactions on Power Systems*, and the *Council on Large Electric Systems*. I served as Program Director of the Edison Electric Institute's *Transmission and Wholesale Markets School*, 1999-2008, an advisory board for EPRI, the economics committee for the National Association of Regulatory Utility Commissioners ("NARUC"), and the forecast review committee for a major electric service provider. I have held the position of chief economist for a regulatory agency, and system economist for a large, integrated electric service provider. I attach hereto and mark as Exhibit "**RC 1**" a copy of my resume.

II. ASSIGNMENT AND SCOPE OF EVIDENCE

7. CAEC was retained to assist The Barbados Light & Power Company Limited (the "Company") to assemble and support the Company's filing before the Fair Trading Commission (FTC) for a change in its retail tariff. My assignments were to provide estimates of the cost of capital and accompanying rate of return recommendation.

8. The scope of my evidence is twofold. First, the evidence presents the Cost of Capital and recommendation for Return on Equity ("ROE") for the Company. The cost of common equity is based on an in-depth cost of capital study, the results of which serve as the basis for the recommended return on equity. Second, the evidence presents the overall Rate of Return ("ROR"), which is set equal to the Weighted Average Cost of Capital ("WACC") and includes the investment components used by the Company to underwrite its rate base. The weighted average cost of capital is based on a regulatory capital structure and includes the cost of debt, the cost of equity, and non-traditional sources of funds. The cost rate of each component is weighted by its respective share balance within the regulatory capital structure. I attach hereto and mark as Exhibit "**RC 2**" a copy of the Study of the Cost of Capital and Rate of Return Recommendation for the Company dated May 20, 2008 which I prepared with the assistance of my colleagues Mr. Bruce Chapman and Mr. Michael O'Sheasy. In my professional opinion, my recommendation for the overall rate of return should be used by the FTC to set the retail electricity prices of the Company in these proceedings.

9. The *Cost of Capital* of the Company includes the rate of interest on the Company's outstanding long-term debt, and the cost rate of common equity contributed by investors. Together, the debt interest rate and equity return rate yield the overall *Weighted Average Cost of Capital*, stated on a traditional capital structure basis. When the long-term debt and common equity balances are combined with other contributed capital including *Customer Deposits, Accumulated Deferred Income Taxes, Deferred Investment Tax Credits* and the *Manufacturers' Allowance*, the WACC reflects a regulatory capital structure, and can be referred to as the overall *Rate of Return*. Cost of capital and rate of return are an essential part of regulatory governance. Since a utility's rate base often constitutes a large cumulative investment amount, comparatively small changes or adjustments to the allowed rate of return can translate into a significant change in operating income and revenue level.

III. EXECUTIVE SUMMARY

10. Fair Rate of Return Principles: It is important that the process of market regulation draw upon well-founded principles which obtain, on a going-forward basis, *returns to capital on prudently incurred investment equivalent* to the cost of capital. Such result strikes a fair balance between the interests of retail consumers and investors who commit capital for the convenience and necessity of the public. Accordingly, retail rates that provide for the realization of returns equal to the cost of capital are viewed as *just and reasonable*. These concepts are codified in the doctrine of Fair Rate of Return.

11. The main features of the Fair Rate of Return doctrine are as follows:

(a) Returns Equivalent to those Realized On Investments of Comparable Risk: As codified in U.S. Supreme Court decisions, capital commitment by investors for the convenience and necessity of the public is entitled to returns equivalent to those realized on investments of comparable risk.

(b) Maintenance of Financial Integrity: The process of regulatory governance, as a practical matter, must result in a flow of revenue sufficient to cover all prudently incurred costs associated with providing *utility services and an adequate return on the capital committed by* investors. In turn, adequate return on capital preserves and maintains the financial integrity of the Company.

(c) Ability to Raise Capital On Fair Terms When Needed: The utility and its investors are entitled to adequate returns on capital so that the utility can raise capital as necessary to provide utility services, on fair and equitable terms and conditions—*i.e.*, at an acceptable interest rate level.

12. Well-Founded Technical Methods. The immediate study of the cost of capital, including general approach and process, employs technical methods that provide a well-founded basis for the recommended rate of return. Because the cost of capital cannot be estimated precisely, it is essential that the rate of return recommendation draw upon several well-recognized cost of capital methods, together referred to as the *Cost of Capital Toolbox.* This multi-faceted approach includes several cost-of-capital methods including the *Capital Asset Pricing Model, Discounted Cash Flow*, and *Risk Premium Analysis.* The *Toolbox* also includes *Comparable Earnings*, based upon historical realized returns of comparable-risk companies, where such returns serve as a basis of expected future earnings performance.[1] The end result is a recommendation that is firmly based in methodology and aligns with Fair Rate of Return principles. In my view, the Company's recommendation for rate of return, as obtained from the cost of capital study fully satisfies these principles. It is thus appropriate and necessary to utilize the Company's recommended rate of return, based on cost of capital study, to determine retail rates in the current proceedings. The end result is an overall price level, as contained in the Company's retail tariff that satisfies just and reasonable criteria.

13. My Overall Rate of Return Recommendation contains the following elements:

(a) Regulatory Capital Structure: A regulatory capital structure should be adopted that includes traditional and non-traditional contributed capital, including balances covering *customer deposits, deferred investment tax credits,* and *deferred manufacturers' allowance.*

(b) Policy-Based Levels of Debt and Equity. The capital structure for regulatory purposes should include 35% debt and 65% equity

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[1] Other approaches are available including Factor Models based on *Arbitrage Pricing Theory* ("APT"), and other well-known techniques to gauge market valuation, such as the Sharpe Ratio.

participation in total capital, *when stated on a traditional basis.* This debt-equity share is determined on a basis of corporate policy, and constitutes a significant departure from the Company's observed capital structure for 2007, with equity participation of 78.6%.

(c) Debt Cost Rates of the Company: The utility assets of the Company are financed by capital committed by both equity and debt investors. It is essential that the FTC recognize the full costs of the Company's outstanding debt including long- and (when relevant) short-term debt cost rates that cover the outstanding debt of the Company.[2] In determining the weighted average cost of capital, interest costs should reflect the observed interest rates in the case of a historical test year or expected interest rates in the case of a projected test year.

(d) Preservation of Income Tax Incentives, Including Deferred Balances of Investment Tax Credits and Manufacturers' Allowances. It is important that regulatory policy adhere to and preserve the investment incentives, including the intended strength of incentives, as put in place by the taxing authority. This feature is manifested in the cost rate applied to the balances of the investment tax credits and manufacturers' allowance included within the regulatory capital structure, where the applicable cost rate is set equal to the WACC of 10.61%, for the traditional capital structure, including a policy-based debt/equity ratio of 0.54 (debt level=35%, equity participation=65%).

(e) Return on Equity for the Company: The FTC should set the rate of return on equity at the estimated cost of equity capital which, in turn, is drawn from observed experience of developed capital markets of sufficient depth, while also taking account of the business context of the Company. As mentioned above, the cost of equity is determined by applying a full complement of cost of capital methods, as applied to the capital market experience of comparable risk entities. The analysis of the cost of equity of the Company draws upon the experience of capital markets in the U.S., Canada and, to the degree appropriate, Caribbean

[2] Because retail prices are set for future timeframes, it may be appropriate to utilize estimated interest rates in the future, as the basis for determining interest rates for debt, particularly short-term debt. Depending on timeframe and circumstances, the expected value of future interest rates can depart significantly from historical rates. However, the observed interest rates of the Company's debt appear to be a close approximation to future interest costs of outstanding debt over the foreseeable future. Estimates of future interest rates, in the form of future spot interest rates, can be derived from observed forward rates.

region. The study recognizes, to the extent necessary, the effects of size and sovereignty risk differences between Barbados and established nations with highly developed capital markets.

14. Overall Rate of Return and Capital Structure. The overall target Rate of Return Recommendation for the Company for the calendar year 2008 is shown below in Table A:

TABLE A
RATE OF RETURN RECOMMENDATION FOR 2008:
WEIGHTED AVERAGE COST OF CAPITAL FOR
REGULATORY CAPITAL STRUCTURE

Capital Component	Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$188,374	31.32%	5.25%	1.65%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$349,837	58.17%	13.50%	7.85%
Customer Deposits	$20,010	3.33%	6.46%	0.22%
Deferred Investment Tax Credits	$30,099	5.00%	10.61%	0.53%
Deferred Manufacturers' Allowance	$13,052	2.17%	10.61%	0.23%
Total	$601,371	100.00%		10.48%

15. As can be observed, the regulatory capital structure includes 31.3% debt, 58.2% equity, and non-traditional components totaling 10.5%, including customer deposits, accumulated investment tax credits and manufacturers' allowance. Customer deposits represent 3.3% of contributed capital, with a cost rate of 6.46%, which is the effective rate of interest paid by the Company to retail deposits retained by the Company. Accumulated investment tax credits make up 5.0%, while balances of deferred manufacturers' allowance occupy 2.2% of the regulatory capital structure. Both carry a cost rate of 10.61% which, as mentioned above, is set at the overall weighted average cost of capital based on a capital structure stated on a policy basis and includes equity participation of 65%.

16. Long-Term Debt Cost Rate. The FTC should utilize the observed cost rate for the Company's outstanding balance of long-term debt of 5.25%. This cost

rate is derived from the calculated interest carrying charges on the Company long-term debt, which carried an average balance of $115 million BBD during 2007.

17. Short-Term Debt Cost Rate. Within the 2007 timeframe, the Company carried no short-term debt balances. However, as a matter of policy, the cost rate for short-term debt should be set at the prevailing or expected interest rate(s) associated with the Company's balances of short-term debt, which may consist of credit balances owed to equipment vendors, commercial paper, promissory bank loans, or lines of credit where the effective interest rate may be linked to the well-known wholesale debt vehicles such as the London InterBank Offer Rates ("LIBOR").

18. Return on Equity. I recommend a ROE for the Company of 13.50%. This result comes about from the application of four methods to estimate the cost of capital for samples of U.S. and Canadian utilities and a sample of low-risk, small capitalization U.S. non-utility companies. The analysis results of these four methods are supplemented by explicit recognition of size premia, sovereignty risks, quarterly dividends, issuance costs, and the Company's comparatively high level of equity participation in total capitalization. Together, these factors imply higher cost of capital and earnings premia, when compared to larger utilities on the continental markets. In short, it is necessary that the Company realize 13.50% rate of return in order to induce investors to commit capital to the Company on fair terms. This rate of return level ensures that the Company, and thus retail electricity consumers, has sustained access to capital markets under reasonable terms on a going forward basis.

19. Table B below summarizes the estimated cost of common equity for each of the four identified methods, as applied to three U.S. samples of comparable risk utilities and non-utility companies or "peer groups," and two samples of Canadian utilities listed on the Toronto Stock Exchange ("TSX"). These samples[3] provide a broad base of financial and equity market experience of utilities and comparable low-risk non-utilities that operate on the North

[3] Samples such as these underlie return on equity estimates incorporated into our studies for other clients.

American continent. Taken as a whole, the risk levels of the companies that comprise the several samples approximate those of the Company, notwithstanding the factors mentioned above—*i.e.,* unique business circumstances including isolation, and sovereignty risks.

TABLE B

MARKET-BASED ESTIMATES OF THE COST OF COMMON EQUITY FOR COMPARABLE RISK COMPANIES

METHODOLOGY	CANADIAN SAMPLES		U.S. SAMPLES		
	Sample 1	Sample 2	Mid-Sized Electric Utilities	Gas Distribution Utilities	Low Risk Non-Utility Companies
Discounted Cash Flow					
Single-Stage Model			10.32%	10.86%	
Capital Asset Pricing Model					
Classsical Single-Factor Model	10.39%	10.60%	11.28%	11.32%	10.35%
Risk Premium					
CAPM-based, Size Premia Adjusted			12.07%	12.12%	12.71%
Realized Market Returns					
5- and 10-year Timeframes	13.36%	16.07%	10.41%	9.34%	10.75%

20. As shown above, market-based estimates of the cost of capital range from 9.34% to 13.36%, excluding the aberrational 16.07% in realized returns for the second Canadian sample, with an average of 11.16%. As mentioned above, the cost of capital and return on equity recommendations incorporate factors that affect the cost of equity, including small size risk, sovereignty risk, and adjustments for quarterly dividends, issuance costs, and differences in equity participation in total capital. In total, these factors are reflected in a low and high range of 2.05% to 2.71%. Adding these factors to the average of the market cost of equity estimates obtains a range of 13.18% to 13.85% with a mid-point of 13.51%. With this range in mind, and given the challenges in precisely determining an adjustment specific to the Company, we recommend a common equity rate of return of 13.50%. This estimate of cost of equity represents a conservative yet reasonable level of allowed return on the capital committed by equity investors to the Company.

21. Barbados Electricity Consumers Are Well Served. The cost of capital study and rate of return recommendation accounts for the business context and capital needs of the Company in a manner that provides for reliable power

supply to Barbados over the foreseeable future. In my view, both consumers and investors are well served by the recommendation.

IV. BACKGROUND: COST OF CAPITAL AND CAPITAL MARKETS

22. The *Cost of Capital* is the underlying interest rate used by investors to discount the expected benefit flows of capital resources including returns to financial assets,[4] and is sometimes referred to as the rate of discount, or simply *discount rate*. The cost of capital is the compensation required by investors for postponing consumption, for expected inflation, and for exposure to capital risks of various dimensions, where such risks are specific to investment vehicles. Cost of capital, book returns, and market returns are measured as a percentage of the investment principal committed by investors, and is usually stated annually.

23. The cost of capital is determined by the demand for capital, supply of savings, expectations of inflation, and perceptions of risks harbored by participants in capital markets. The demand for and supply of capital are determined by expectations of future levels of economic activity, while expected inflation is driven largely by monetary policy over the relevant timeframe. Perceptions of risk, in turn, cover many dimensions including uncertain government policy, the effects of natural phenomena such as weather including violent storms, droughts, and floods; and, in some regions of the world, war and civil unrest. Currency risks enter the picture in the case of foreign investment under conditions of floating exchange rates or where currencies may be revalued within the relevant timeframe. The cost of capital—the discount rate stated in nominal terms—increases with rising demand for capital, with expectations of higher rates of inflation, and with heightened perceptions of risk. Arguably, risk is the key contributing factor to the cost of capital.

[4] Financial assets constitute one form of capital. More generally, *Capital* refers to economic resources of a durable nature that contribute to the production of goods and services, or may provide services directly. Capital resources of an economy are readily at hand; examples include manufacturing equipment, software, commercial buildings, residential dwellings, streets and highways, airports and, importantly, the accumulation of skills and knowledge of the workforce. Capital is accumulated savings over time, where savings refers to the proportion of the output of an economy that is not consumed as current goods and services. Essentially, savings is the share of output held back and invested in—*i.e.*, put into—capital resources. The cumulative level of investment over time, covering decades, constitutes the capital stock of an economy and the society that it serves.

24. Financial assets include a multitude of debt vehicles, equity, and derivates tailored to participants of capital markets, where participants include households and small investors, small businesses, corporate organizations, and government entities. Participants across these segments—i.e., investors including lenders and holders of common and preferred stock—can supply capital while other participants (such as borrowers and common stock issuing companies) demand capital. Commercial banks, credits unions, finance companies, capital exchanges, insurance companies, serve as intermediaries that provide the institutional means that facilitate the interaction and linkage of the supply and demand sides of markets. These functions essentially include lending and borrowing, the issuance of equity vehicles, and mechanisms to hedge risks. Banks and credit unions borrow (and store) financial assets that in turn are invested in the form of debt and, to a lesser extent, equity. Household debt vehicles include, for example, personal loans covering appliances, household services; credit card mechanisms through finance companies and banks; and real estate loans. Business loans include short-term loans and lines of credit with banks, inventory financing through business wholesalers, and commercial paper of various terms and credit risk ratings. Corporate debt can be in the form of lines of credit with banks, and mortgage and debenture bonds, while government debt can be in the form of revenue bonds of cities, and short- and long-term debt of various terms, including a range of asset-based financing.

25. *Equity* (or, *Common Equity*) refers to net accumulated value of the contributed capital by investors. Generally speaking, equity is in the form of common and preferred stock and includes the accrual of retained earnings, where the investor, through the purchase of stock, assumes a share in the ownership of a corporate entity. In some cases, debt instruments can participate in equity returns and may also have rights of conversion to common stock. Derivatives are financial instruments whose value depend on investor expectations regarding the inherent value of the underlying assets. Derivatives, the common forms of which include options and forward contracts, provide a basis for speculation and for hedging of risk associated with the value of the asset. Of late, the turmoil within financial markets have focused on a form of derivative assets referred to as credit default swaps ("CDS") which function as insurance.

26. The cost of capital associated with financial assets is determined by investors and, in the large, by individuals and entities (including government entities) that provide savings and thus the accumulation of capital. In the case of financial assets, expected benefits are in the form of future cash flows including interest payments, dividend payments, market appreciation, and return of principal. When investors supply funds to entities such as utilities and governments, not only are they postponing consumption—giving up the value obtained from alternative expenditures—they are also exposing funds to the potential devaluation from ongoing inflation as well as to various uncertainties and risk that attend future cash flows. Investors are willing to incur these risk factors only if they are adequately compensated. While the market prices of other inputs including labor, materials, and energy can be easily verified, the cost of capital—essentially, the price of capital—is not easily discerned and, all too often, requires estimation through the cautious application of analytical methods. The cost of capital remains positive in the absence of inflation and risks, as savers require compensation for foregoing the right to use the funds saved for consumption of goods and services—essentially, the time value of money.

27. In addition to the global risks alluded to above (weather, government policy, etc.) dimensions of risk also cover idiosyncratic factors associated with specific capital resources, such as those of individual entities or companies. Accordingly, financial markets will re-price downward the bonds of a private company, should the *current* financial condition of the company suddenly decline. Essentially, the decrease in the company's current condition reflected as reduced interest coverage—causes the expectation of the future condition of the company also to decline. Expectations of future financial conditions (possible states) of the specific company are idiosyncratic risks. Because cost of capital rises with increased risks, the price of the bonds declines. Bond prices and discount rates, in the form of the net interest rates or bond yields (and yield to maturity), move in opposite directions; bond yields increase as bond prices decline, and decrease as bond prices rise.

28. To facilitate the commitment of capital (investment) by savers and their agents to the firm, the firm offers property rights, including bonds or promissory notes to debt holders and shares of stock to equity investors. These property rights define the commercial terms and conditions under

which savers and their agents, as investors, commit capital. Property rights are capital (financial) assets, and are generally tradable in organized financial markets or on an *over-the-counter* basis. Financial assets are claims on the income of the firm as compensation for the commitment of capital, and are the financial obligations of the firm. Shares of stock constitute ownership in the firm.

29. In the case of long-term debt—*i.e.,* mortgage bonds, debentures, and long-term notes—the interest on the principal (face) amount of a bond (debt) or the coupon rate on the share of preferred stock defines the level of compensation. Often, the interest rate is a predefined annual rate that remains fixed over the term of the debt. However, long-term debt instruments can have a number of other provisions that, in essence, provide for more complete contracting by managing risks through risk sharing between the debt holders and the borrower (the firm). These provisions can include: 1) adjustments to the rate of interest to reflect contemporary market conditions *and* rates of inflation, 2) participation in the earnings of the firm, 3) conversion rights, and 4) voting rights in the management of the firm.

30. In the case of short-term promissory notes, agreements with commercial banks define the mechanism by which interest, stated in dollars, is determined. Often, the commercial terms of promissory notes define interest to be paid monthly on the outstanding daily balance (principal outstanding). The rate of interest applied to the outstanding balance is typically tied (indexed) to the interest rate on obligations of some widely known financial market—say, the London Interbank Offer Rate (LIBOR) or Fed Funds—which also varies daily or monthly.

31. Common stock property rights are somewhat different from other financial obligations because, as owners of the firm, the returns to shareholders are residual amounts following the compensation of other resources employed by the firm including debt obligations. Common equity is essentially compensated last, and bears the burden of much of the business, regulatory, and financial risks of the firm. For this reason, common equity is, in virtually all cases, more costly than other forms of financial instruments.

32. As with other durable goods markets, capital markets have primary and secondary dimensions. Primary markets are the institutions and processes that facilitate the initial sale of the financial obligations of the firm to initial investors, whereas secondary markets are structured market processes that provide the means by which investors can purchase and sell existing rights, including shares of stock and debt obligations. The cost of capital can be differentiated between primary and secondary markets. As an example, the interest rate yields to maturity, as realized in primary market auctions of U.S. Treasuries referred to as "on the run yields," are typically lower than secondary market yields on "Treasuries," referred to as "off-the-run". Financial instruments can assume many forms, and debt securities (bonds) and equity shares are actively traded in financial markets, which are generally considered to be highly liquid and competitive. However, to the degree that financial obligations 1) carry specialized and non-common commercial terms, and 2) secondary—and to a lesser extent, primary—markets are less liquid, holders of such obligations assume higher risks, other factors held constant. This is the case where the pool of buyers and sellers is limited and the volume of transactions is comparatively small. Relatively low levels of liquidity imply higher transaction costs and risks to investors, which translates directly into higher costs of capital to the firm.

33. Competition is a term that describes some markets, and markets are said to be competitive if certain conditions exist. Markets can be characterized as competitive if they involve: 1) a very large number of buyers and sellers, 2) information relevant to the determination of prices is readily available, complete, and not unduly costly, and 3) transactions costs are low. Because of the workably competitive nature of financial markets, arbitrage opportunities are more or less exhausted. This means that, for both primary and secondary markets, financial property rights (the securities themselves) trade at levels (prices) such that perceived risks and opportunities for prospective returns to capital are appropriately balanced and approximate those of other investment opportunities. Thus, above-normal returns, which implicitly include compensation for risks, cannot be seemingly realized by investors over prospective periods in systematic fashion.

34. Under the assumption of market efficiency, the competition inherent in U.S. and worldwide financial markets implies that the prices of common shares

(share prices) and bonds are at a level that reflects the opportunity cost of capital. As an example, assume that the perceived risks attending the returns to common shareholders of Firm A are equivalent to those of Firm B and other firms. If the share prices of Firm A suggest a market return of 10%, while the prices of Firm B and other firms of comparable risks suggest (allow) market returns of 13%, the market price of Firm A will fall to a level that provides a basis for market returns of just 13%, prospectively. A price that allows for a 10% prospective market return is insufficient in the presence of opportunities for a market return of 13% on alternate investments of comparable risk. Essentially, the 13% market rate of return on investment alternatives constitutes the opportunity cost of capital. Most remarkable is the expedience—literally, in minutes for highly liquid financial markets—with which share prices adjust to levels that appropriately balance prospective returns to equilibrium levels *based upon perceptions of risks*. In short, equivalent and comparable risks translate directly into comparable rates of return, which is the cost of capital of common shareholders in—and thus of—the firm.

35. As mentioned early on, the cost of capital is a function of the demand for and supply of capital, investor expectations of inflation, and investor perceptions of risks. Because the conditions of demand and supply as well as expectations of inflation are more or less common to financial markets at any point in time, financial vehicles are differentiated by risks. Hence, the expected returns and prices of bonds and common shares (normalized for denomination and size) at any point in time are largely if not exclusively differentiated by perceptions of risk. Income taxes also affect market interest rates.

36. In summary, whereas the cost of skilled labor, materials and supplies, and fuel used in the process of providing utility services are expressed in money terms, the cost of capital is expressed as an interest rate, typically shown as an annual percentage of investment. This means that the costs of the capital resources employed by the Company including generation equipment, power delivery systems such as transformers and lines, meters, trucks and vehicles, computer systems, software, office facilities and buildings, inventory and stores, and land—essentially, the rate base of the Company—are reflected as annual carrying charges. The cost of capital for the Company—or perhaps

more accurately, the *cost rate of capital*—is referred to as the *required rate of return* (%) on the capital resources committed by investors to the Company, where capital is valued at either original cost or fair value.[5]

V. FAIR RATE OF RETURN AND CAPITAL ATTRACTION

37. Legal guidelines for rate of return utility regulation of the North American Continent have been discussed extensively, and are delineated by key decisions of the legal authorities in the U.S. and Canada. As a point of departure, the statutory principles of rate of return for public utilities rest substantially with two decisions of the Supreme Court of the United States. In the **Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia** case (262 U.S. 679, 1923), the U.S. Supreme Court set forth its view on fair rate of return, as follows:

> "...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 risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises 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. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally."

38. A second landmark decision of U.S. Supreme Court echoed and expanded upon the fair return standard established by the "Bluefield" decision cited above, for capital committed to public utilities. This second decision is the

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[5] For the determination of setting retail utility prices in the U.S. and elsewhere, the regulatory convention is to value the capital of public utilities at original cost.

Federal Power Commission v. Hope Natural Gas Company case (320 U.S. 391, 1944); a relevant passage of this latter decision is as follows:

> "From the investor or company point 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 return 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 attract capital."

39. These longstanding decisions provide the recognized framework for the fair rate of return on capital committed by investors to public service. In these decisions, the U.S. Supreme Court codified, in clear and readily understandable terms, a statutory benchmark that serves as the basis to set fair and equitable prices for retail public services such as natural gas, while also providing a fair rate of return on the capital provided by investors. Though they reach back many years, these decisions remain to this day the cornerstone for the determination of rate of return requirements. The challenge for regulators, regulated utilities, and interested parties to regulatory proceedings is to operationalize these principles in contemporary regulatory processes.

40. As noted by Professor Roger A. Morin in his testimony before the New Hampshire Public Utility Commission:

> "Subsequent cases have reaffirmed the standards established by the **Bluefield** and **Hope** cases.[6] In the **Permian Basin Area Rate Cases** (390 U.S., 747, 1968), the U.S. Supreme Court stressed that:
>
> > "the court must determine whether the order may reasonably be expected to maintain financial integrity, attract necessary capital, and fairly compensate investors

[6] As discussed in Roger A. Morin, Regulatory Finance: Utilities' Cost of Capital, Public Utilities Report Inc., 1994, pp. 10-11, these cases include Federal Power Commission v. Memphis Light, Gas & Water Division (411 U.S. 458, 1973), Permian Basin Area Rate Cases (390 U.S., 747, 1968), and Duquesne Light Company et al. v. Barasch et al. (488 U.S. 299, 1989).

for the risks they have assumed, and yet provide appropriate protection to the relevant public interests, both existing and foreseeable. The court's responsibility is not to supplant the Commission's balance of these interests with one more nearly to its liking, but instead to assure itself that the Commission has given reasoned consideration to each of the pertinent factors.""

41. Moving further down this path, the U.S. Supreme Court, in its decision in **Duquesne Light Company *et al.* v. Barasch *et al.*** (488 U.S. 299, 1989), explicitly recognized risks associated with changes in regulatory governance. In addition, key decisions in Canada align with the expressed views of the U.S. Supreme Court cited above.[7]

42. These principles support the practical experience and management of small firms and corporate entities. The cost of capital concept may also be interpreted from the perspective of internal investments and the demand for resources. Regulated utilities accommodate the ongoing and steadily rising demand for services, which involves expanding employment of resources, capital in particular. Senior managers of firms, as agents for the ownership or controlling interest of the entity such as shareholders or a local municipality, are responsible for ensuring that the expected internal returns on incremental capital committed by the firm are equivalent to the cost of capital to the firm—*i.e.*, investors' rate of return requirements. The adequacy of the internal returns on incremental investment by electric utilities to fund capital at full opportunity costs, however, is highly dependent upon the soundness of the regulatory governance structure to ensure that the utility has a viable opportunity to obtain sufficient revenues, which in turn provide adequate returns on new capital.

[7] Specifically, the perspectives expressed within selected Canadian decisions including Northwestern Utilities v. City of Edmonton (S.C.R. 186, 1929), and British Columbia Electric Railway Co. v. Public Utilities Commission of British Columbia (S.C.R. 837, 1960) amply demonstrate a similar line of reasoning and guideline for Canadian regulatory authorities to that of the U.S. Supreme Court decisions, for the setting of the fair rate of return level for utilities. For a more complete discussion of legal guidelines and landmark court decisions, please reference Roger Morin, *Regulatory Finance*, and Charles F. Phillips, *The Regulation of Public Utilities*, 1988.

43. When the rate of return, as set by regulators, leads to inadequate returns to capital or to the expectation that returns to capital are likely to be insufficient, utility managers are understandably reluctant to make investments in infrastructure. Indeed, when the expansion of capital resources occurs under a regulatory requirement including the obligation to serve, the absence of adequate returns implicitly constitutes the confiscation of the capital. Under these regulatory conditions, the utility is forced to provide services that involve new investment, even though adequate returns are not obtainable. The result is a failure of capital attraction by the utility, and the confiscation of capital of investors—an outcome that comes about from the inherent efficiency of competitive capital markets.

44. Investors, investment rating agencies, investment banks, and commercial bank lenders follow regulatory developments. Anticipating a shortfall of the internal returns to capital with respect to rate of return requirements, capital markets bid down the prices of the outstanding securities of the utility. The reduced market capitalization of the utility constitutes, arguably, the confiscation of the existing capital of holders of the utility's securities. Essentially, the utility has failed to (or simply cannot) attract capital on fair terms—terms that do not cause outstanding investors to incur wealth losses.

VI. <u>WEIGHTED AVERAGE COST OF CAPITAL</u>

45. Capital *Structure* refers to the means—*i.e.*, financial vehicles—by which private and public entities underwrite physical capital and other assets. Capital structure can involve several types of mechanisms including long- and short-term debt, preferred and preference stock, common equity, and capitalized leases. These traditional types of mechanisms, under economic regulation, are often augmented by other sources of funds including customer deposits, and deferred balances for income taxes, investment tax credits and, in the case of the Company, manufacturer's allowance.

46. The relevant financial policy issue is the level of financial leverage, measured as the ratio of debt to equity that comprises the capital structure stated on a traditional basis. Because debt is generally less costly than equity, it is appropriate for the firm to underwrite its assets with some degree of financial leverage. The appropriate amount of leverage is a matter of operating and

business risk, measured by the expected level and variability (mean and variance) in future operating income. In brief, highly stable flows of operating income (and internal cash), which can be interpreted as the total book returns to capital, provide a basis for the firm to employ higher levels of debt. Higher leverage, however, increases the variability of interest coverage and thus the cost of debt, *and* the cost of equity as a result. Thus, the financial policy issue regarding debt leverage is a matter of determining the level of debt that minimizes the weighted average cost of capital ("WACC"). At relatively low levels of debt, the WACC declines as leverage rises. However, beyond a certain point, the expected level and variability of operating income of the firm relative to equity ownership value begin to rise, causing the WACC to increase. In short, the cost rates of debt and equity are sensitive to the debt and equity participation levels within total capital. The relevant question, then, is: what is the appropriate and acceptable level of leverage, given the inherent business and operating risks of the firm?

47. Decades back, it was common for electric utilities to underwrite assets with upwards of 60-65% debt and corresponding levels of equity participation of 40-35%. Currently, however, both mid-sized and large electric utility companies typically finance assets with participation shares of 48-58% debt, and 52-42% equity. The gradual evolution favoring lower levels of debt financing is in response to, and is in keeping with, changes in the electricity services industry. Also, debt levels carried by non-financial sectors have generally receded. Several recent changes in the business environment facing electric utilities have precipitated the reduction in debt financing. These are: market restructuring involving competitive entry for generation and other unbundled services; sharp increases in input costs; closer integration of electricity services and energy markets generally, where energy commodities reveal much higher levels of price variation and volatility; less restrictive regulatory governance structure, including price cap regulation and earnings sharing mechanisms; and uncertain future requirements for environmental compliance.

48. As a general rule, the governing regulatory authority should adopt the observed historical or projected capital structure, including regulatory (non-traditional) components, where such result is well aligned with least-cost principles. However, where the observed capital structure constitutes a clear

departure from least cost—with unusually high concentrations of debt or equity participation—it may be appropriate for the authority to consider the adoption of a hypothetical or imputed capital structure. In addition, in the case of isolated service providers such as utilities like the Company with the operation of its island power system, or where the utility is unusually small sized and is susceptible to unforeseen business events that cannot be readily diversified or insured, it may be appropriate for regulatory authorities and the utility to employ a higher concentration of equity participation.

VII. WORLDWIDE CAPITAL MARKETS AND CURRENT CONDITIONS

49. This section begins with a description of general trends in capital markets through increased globalization, and then focuses on contemporary conditions in global capital markets which of course are an immediate concern of the FTC and the Company.

50. Arguably, the most significant development in capital markets over recent years has been the globalization of capital flows that, to a substantial extent, has been facilitated by the vast expanse of electronic media. When coupled with a substantial expansion of financial services geared to hedge risks through an ever larger array of tradable products at the wholesale level, worldwide *real markets* have become inextricably interconnected. The implications are several. First, the Company and entities worldwide compete for capital resources in the face of vastly expanded opportunities for capital as the barriers to capital flows among nations are removed. Second, unexpected capital gains and losses in financial assets which originate in one area or region affect real economies worldwide. In particular, capital stresses such as the current turmoil of financial markets can impose large capital losses on the holders of financial assets internationally. Third, the sheer volume of financial services cause financial markets to have strong, negatively reinforcing effects on real markets. In short, economies worldwide, which increasingly serve as the primary means by which individuals and households obtain economic value and worth, appear to be much more vulnerable to capital risks currently than in previous eras.

51. As an example of the globalization of the capital markets, net private capital (*i.e.*, debt plus equity) flows to developing countries increased from $188

billion in 2000 to $491 billion in 2005 and to $647 billion in 2006.[8] Equity flows in 2006 comprised $419 billion, nearly 75% of total flows, in sharp contrast to the experience of earlier years. As an example, capital flows into developing countries in 1990 were approximately $60 billion for debt, and $40 billion for equity. Equity flows continue to increasingly dominate the share of total flows, in part due to an abatement in the level of lending among agencies and institutions of sovereign nations, referred to as official lending. For example during 2006 official lending actually declined while total flows increased by 17% from 2005 levels. As the 2006 World Bank Report states:

> "Demand for emerging market debt and equities remained strong, spurred by improved fundamentals in many developing countries and investors' search for higher yields in an environment where long-term interest rates remain low in major industrial countries, despite higher short-term interest rates".[9]

52. This trend continued through year-end 2007 and extended into perhaps mid-2008, when the effects of the comparatively deep and long U.S. recession, which was initially manifested in the decline in total employment, began to take hold. For context, it is instructive to review recent trends in capital flows worldwide and, at a summary level, it useful to mention several key findings of the 2007 World Bank Report cited above, as follows:

 (a) Inflows of capital of developing countries are an increasingly large share of total world capital flows, and their financial positions have steadily improved since 2001-2002, years of very slow real growth. Specifically, equity inflows to developing countries other than China were $94 billion in 2006, which is in sharp contrast to the $6 billion level for 2001-2002.

 (b) Developing countries have reduced external debt, lengthened maturities, and bought back outstanding debt, often using expanded currency reserves obtained through expanded exports to OECD

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[8] Source, The World Bank, "Global Development Finance: The Development Potential of Surging Capital Flows – Review, Analysis and Outlook, 2006," and "Global Development Finance, 2007," hereafter referred to as the "World Bank Reports").

[9] The World Bank Report, 2006, p. 18.

nations. Net lending from the Paris Club of creditors declined sharply in 2006.[10]

(c) Equity firms located in developing nations have undergone a vast expansion of cross listing of their equity shares on world exchange markets in order to build channels for expanding capital needs, even when doing so implies that they need to satisfy higher accounting and financial reporting standards.

(d) Foreign corporations are increasingly borrowing on international markets as a result of favorable interest rates and declining sovereign risk spreads. Additionally, foreign firms are increasingly utilizing advanced risk management tools in order to hedge currency and commodity risks, necessary as commodity exports, particularly oil and other natural resources, have assumed a much higher share on a value basis of total exports of developing countries.

53. The development of global capital markets parallels expanded development of economic activity. Indeed, world GDP expanded 5.3% in 2006. Participating in high levels of economic growth are nations in the South American and Caribbean region, which experienced 4.7% and 5.6% expansion of real activity in 2005 and 2006, respectively, with continued growth of 4.3% projected for the 2007-2009 timeframe.[11]

54. The development of global financial markets both parallels and contributes to expanding economic activity. Global markets and the resulting capital flows are much more integrated now than in previous eras and, as a result, investors have a substantially larger set of opportunities to place capital, including investments in utilities in other energy markets and other regulatory jurisdictions. The emergence and development of robust global capital markets over the past decade, in particular since 2001-2002, has placed the Company and other utilities within the Caribbean region in the position of

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[10] The Paris Club refers to an informal group of 19 established nations committed to reducing the debt burdens of poor and developing nations worldwide. Debt relief, as orchestrated by Paris Club, comes about through debt restructuring including changes in debt duration, interest rate subsidies, and outright forgiveness of outstanding principal. For Heavily Indebted Poor Countries (HIPC), Paris Club claims that the debt service has declined from over 5% of GDP in 2000 to 1.5% in 2006. However, Paris Club cites declining financial worthiness of the HIPC group of nations since mid-2008. The Paris Club reaches back to 1956.

[11] World Bank Report, 2007.

competing for capital with developed and other developing countries, as well as the complete gamut of industries and economic sectors that are seeking capital resources. The global nature of capital affects utilities and is relevant *for both debt and equity funding*.

55. Global capital markets today are driven to a substantial extent by institutional investors. Institutions are likely to prefer or may have mandates to remain fully invested and seek out "undervalued" assets. Finally, strategic institutional investors, like pension funds, life insurance companies, and sovereign wealth funds are growing in importance in worldwide financial markets. The increasing sophistication of these institutional investors means that they are able to differentiate between country- and company-specific investment opportunities. This translates into investment behavior that pays close attention to the risk profiles of the set of opportunities that they face, including utilities and other energy market equities, when making decisions about strategic placement of funds.

56. In summary, the clear implication is that the Company and other entities large and small must compete for funds globally. Globalization of capital flows is no doubt manifested in multiple dimensions. For our immediate purposes, however, one salient point matters most: the prospects of future returns and capital risks associated with a capital position in the Company as gauged by the holders (investors) of capital, are *benchmarked* with respect to the expected returns obtainable from alterative investment opportunities of comparable risks elsewhere. The universe of opportunities is large, and one can expect that investment opportunities are fairly gauged in terms of risks and potential returns.

VIII. STRESSES IN THE WORLD ECONOMY AND FINANCIAL MARKETS

57. Contemporary stresses experienced by all corners of financial markets have been induced by excessive levels of leverage in selected major western economies, notably including the U.S., United Kingdom, Ireland, and Spain. *High levels of leverage—more specifically, unsustainable carrying charges of* debt obligations of households, commercial real estate, and financial services sectors—precipitated from the depths of the 2001 U.S. recession, and

became a serious condition during 2005-2006.[12] At a general level, the reasons are several. First, historically low interest rates induced a boom in real estate mortgage activity, within both commercial and residential sectors. Mortgage interest rates in the U.S. fell 220 basis points during this period—*e.g.*, from 8.04% during 2000 to 5.84% in 2004 according to financial information compiled by the Federal Reserve Board. Second, a decade and a half of low price inflation and high levels of stability and growth in economic activity, prosperity, and employment[13] caused economic agents (households, firms, and government policy makers) to underestimate risks. Third, the wide-scale application of structured finance—*i.e.*, collateralized debt obligations ("CDOs)—and derivative products such as credit default swaps ("CDSs") within wholesale financial services exposed financial markets to a potential contagion of much higher counterparty default risks, as perceived, leading to a collapse in financial market activity.[14]

58. The overall U.S. economy in 2007 produced roughly $15 trillion in net output. While the U.S. economy, like the economies of the U.K. and Spain, was not carrying disproportionately high levels of debt overall, households and the financial sector were, as is now appreciated, over-leveraged. Key insights are twofold. First, the unwinding of the high debt levels in these sectors imposed serious negative impacts on the overall economy, when defaults by individual households and financial firms are highly correlated and occur simultaneously. Second, the expectation of sharply higher rates of default on the outstanding debt of households, financial firms such as Lehman

[12] For U.S. households, outstanding mortgage debt rose from $5.3 trillion to $9.8 trillion U.S. from 2001 to 2006, an average change of 12.6% per annum, which is about 10% annually in real terms. In contrast, U.S. mortgage debt increased from $2.5 trillion to $4.8 trillion U.S., from 1991 to 2001, an average change of 6.8% per annum or about 4.0% in real terms annually, which is only slightly above the rate of growth real activity over these ten years. These data are reported in the *Flow of Funds Report* provided by the Board of Governors of the U.S. Federal Reserve.

[13] This era is sometimes referred to as the *Great Moderation* in the U.S. and the *Great Stability* in the U.K. Reference "The Credit Crunch of 2007-2008: A Discussion of the Background, Market Reactions, and Policy Responses" by Paul Mizen in *Review*, Federal Reserve Bank of St. Louis, September/October 2008.

[14] Structured financial obligations—in particular, mortgage-backed securities (MBS)—were held as portfolios in *Structured Investment Vehicles* (SIVs) and carried as highly leveraged off-balance sheet entities by commercial and non-commercial banks. In many cases, mortgage-back securities and other CDO's were insured with credit default swaps, and leveraged with short-term rated commercial paper.

Brothers,[15] and production oriented corporate entities such as General Motors Corporation created an environment of much higher risk, one in which the perception that risks could change rapidly. In turn, economic actors (households, firms, banks) were unwilling to engage in transactions such as the purchase of capital equipment or the lending of corporate bonds, where the transaction involves long-term commitments.

59. The effects within the financial economy have had negatively reinforcing impacts on the real economy. The result has been significant declines in economic activity, manifested as reduced employment, higher household savings, reductions in investment including construction of structures and the implementation of equipment and software, high inventory levels (at least initially), and fiscal pressures across government entities caused by reduced tax revenues.

60. It is now clear that, beginning in the fourth quarter of 2008, the world entered a serious recession.[16] The consensus view holds that, because of the critical role that financial markets play within market economies generally, forestalling further declines—or at least mitigating the damage in the form of lost economic output over months and years—requires substantial intervention by public authorities. Notable action has been taken within the U.S., including that of the Federal Reserve System, the U.S. Treasury under newly authorizing legislation by the U.S. Congress, and by the Federal Deposit Insurance Corporation.

61. The specter of large financial losses by major institutions became apparent in the U.S. in mid- to late-2007. It is not surprising that the U.S. has been deeply involved in and committed to dealing with the impending recession that it caused. So far, intervention by authorities has involved orchestrating

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[15] Examples of the astonishing level of leverage carried by commercial and wholesale financial institutions are readily at hand. For example, Lehman Brothers' assets of well over $700 billion U.S. at year-end 2007 were underwritten with a mere $30 billion of equity, with the remainder debt financed.

[16] The IMF, in its *World Economic Outlook* for October 2008, predicted that the world economy would slow to a 3.0% increase in real gross world product during 2009. This outlook has overgone significant revision, as evidenced by the IMF's recent projection for 2009, in which the world's real economy is expected to decline by 1.3%. Clearly, the IMF—and many others—did not fully appreciate how, as a result of the increasingly strong linkages among economies, world output across regions is codetermined. For a useful discussion of the interdependency of national economies as a consequence to global capital flows, see Krugman, Paul, *The International Finance Multiplier*, October 2008.

major reductions in short-term interest rates by the Federal Reserve—the interest rate on Fed Funds was lowered from 5.25% in mid-2007 to 2.00% in mid-2008 and then to the range of 0.0%-0.25% by late 2008. Early on, the U.S. Federal Reserve System anticipated the need for the immediate availability of cash equivalent funds and, by early 2008, created special facilities to ensure the availability of liquidity including, notably, the Federal Reserve Auction Facility and the Commercial Paper Funding Facility.

62. In the U.S., institutions designed to ensure protection of financial assets have been in place for decades and it is not surprising, given current conditions that the Federal Deposit Insurance Corporation (FDIC) has intervened frequently during mid-2008. This intervention has taken the form of the seizure of several major financial institutions prior to their outright failure.[17] In two cases, this involved the orchestrated sale of asset of the failed institutions, notably, in the case of wholesale markets, the near-failure of Bear Sterns in March, 2008 and, in the case of retail markets, and the seizure of Washington Mutual in September, 2008. The Bear Sterns purchase by J.P. Morgan was conditional on the guarantees by the U.S. Treasury to the acquiring institution against potential losses on certain categories of financial assets (CDOs). However, in the case of the collapse of Lehman Brothers (September 2008), no such guarantee was forthcoming, an event that precipitated a major contraction in short- and long-term lending across wholesale financial markets worldwide. The seriousness of the situation gave rise to legislation establishing the Troubled Asset Relief Program (TARP) operated by the U.S. Congress, funded by $700 billion U.S. (September 19, 2008 Under TARP, the U.S. Treasury has injected equity capital into the balance sheets of selected retail and wholesale financial institutions, implemented through the purchase of convertible preferred stock. In order to ensure the continued functioning of U.S. mortgage markets, the U.S. government has placed the Federal National Mortgage Association and Federal Home Mortgage Corporation under a program of closely supervised stewardship. In doing so, the government has sought to guarantee the outstanding financial commitments of these institutions, which are essential to

[17] The Federal Deposit Insurance Corporation current identifies well over 35 financial institutions that it describes as failed, since mid-2008.

the workings of U.S. real estate markets.[18] While the crises originated in the U.S. a number of interventions by national governments and the IMF were occurring simultaneously on the world stage.[19]

63. The stresses inherent in financial markets are manifested in interest rate spreads, which can be viewed risk margins, between debt obligations of varying risks. It is useful to review interest rate spreads over time and review how they have changed. Heightened risks of contemporary markets are, of course, present within both short- and long-term debt obligations including the risk margins (premia) between LIBOR and short-term U.S. Treasury bills, and between BAA corporate securities and U.S. Treasury securities. In the case of the LIBOR-Treasury Bill margin, the interest rate margin typically resides within a fairly narrow range of 35-50 basis points. This historical perspective contrasts greatly for the LIBOR-Fed Funds margins beginning in May of 2008, as shown below in Table C:

[18] Financial surety began to seriously unwind in September, 2008. The chronicle of U.S. events beginning provides testament to the serious nature of the contraction in financial transactions. Events include Fannie Mae and Freddie Mac forced into trusteeship on September 7; Merrill Lynch purchased by Bank of America on September 14; bankruptcy filing by Lehman Brothers following the attempted sale to Bank of America or Barclays on September 15; AIG obtains a 2-year loan of $85 billion from the Federal Reserve on September 16; Morgan Stanley and Goldman Sachs become holding companies (which allows them access to Federal Reserve funding and asset guarantees) on September 21; Washington Mutual fails and, through liquidation, its assets are sold through a receivership to J.P. Morgan beginning on September 26; and TARP is initiated by Congress on October 1. Though not cited herein, the chronicle of important events continues unabated well into 2009.

[19] Notable events include Lloyds TSB takeover of Britain's largest mortgage lender, NBOS on September 17; the government of Iceland's seizure of Glitnic, the nation's largest bank on September 29, 2008; Iceland nationalizes Landsbanki on October 7; L500 billion commitment by the government of the U.K. to stabilize U.K. financial institutions through the implementation of a 3-tiered program; and the IMF commitment of loans to the Ukraine ($16.5 billion) and Hungary ($15.7 billion) on October 27.

TABLE C

Month	LIBOR minus Fed Funds Margins (Basis Points)
May, 2008	94.2
June	91.5
July	116.7
August	108.5
September	206.6
October	329.9
November	206.4
December	175.6
January, 2009	108.3
February	94.9
March	104.9

64. A similar story is obtained from the risk margins revealed by the yields for BAA corporate securities and U.S. Treasury securities (7-year constant maturities). During periods of fairly high levels of confidence, the risk premium on BAA securities is about 200 basis points. During recessions, credit worthiness of private firms generally declines and it thus not surprising to find that the risk premia of private debt obligations rise. As an example, the average risk premium on BAA corporate securities over U.S. Treasuries rose to 328 basis points during the recession and early recovery of 2001-2002. For recent months, the BAA corporate-Treasury risk premia have risen significantly, as shown below in Table D:

TABLE D

Month	BAA Corporate minus U.S. Treasury Securities Margins (Basis Points)
May, 2008	347
June	334
July	356
August	369
September	406
October	569
November	639
December	654
January, 2009	616
February	578
March	600

65. In summary, evidence clearly suggests that as a result of stresses inherent to financial markets, risk premia reside at comparatively high levels during the contemporary timeframe. No doubt, the deep recession contributes to these higher risks. Risk premia of course are implicit within the cost of capital, which leads one to conclude that the cost of capital for investor-owned firms across capital markets worldwide currently stands at high levels, stated in real terms. If the Cost of Capital Study for the Company were to be updated, the study results would likely suggest that the rate of return for the Company, reflecting opportunity costs, would be little different though somewhat above my current recommendation. While expected inflation and real interest rates have declined somewhat since 2007, the movements of nominal interest rates—e.g., yields to maturity for non-Treasury securities—suggest that market risk premia have risen, leading to higher required returns for long-term private investment of all forms.

IX. SOVEREIGNTY RISKS

66. *Sovereignty risk* refers to the risk differences among comparable types of financial assets, including government and corporate bonds and common stocks, according to the country of origin of the asset. Sovereignty risks are evidenced by observed risk premia among financial assets across countries, and are most relevant for developing nations and regions where risk differences with respect to developed economies reflect the inherent level of uncertainty and risks of emerging economies. Emerging markets are typically less developed and complete, are notably more vulnerable to currency risks, and are much less capable of diversifying exports and the effects of widely varying world commodity prices. Similarly, the financial assets sourced in emerging markets are less liquid and may not reflect full information reporting standards. Moreover, investors in emerging markets are likely to have less complete information and knowledge regarding the full extent of risks, including political and more general institutional intricacies. Finally, some regions experience periodic or chronic levels of civil unrest and warfare. As expected, observed differences in market yields on outstanding debt securities across nations suggest that so-called sovereignty risks vary greatly. The relevant question is how best to gauge the risk premia associated with the financial assets of emerging economies, where the focus is common equity.

67. Under conditions in which the underlying assets are traded within sufficiently competitive and liquid markets, the well known tools of capital valuation, including Capital Asset Price Model (CAPM) and Discounted Cash Flow, provide a basis to develop estimates of the cost of capital. In the case of emerging markets, however, financial markets are often incompletely developed. The market size (capitalization) of debt obligations and common stocks traded on the exchanges of emerging markets are typically of small scale; the number of listings are often few, and trading activity is thin and often intermittent. In short, the relevant valuation tools, as developed by and actively exploited within the financial markets of the developed economies of the West and the Far East, are not easily applied. Consequently, several sensible though *ad hoc* approaches for determination of sovereignty risks have been and are applied in lieu of formal valuation methods, at least as applied to the within-nation exchange experience. These methods include:

(a) *Nation-Specific Equity Market Risk Premia*: Using a worldwide equity market index such as Morgan Stanley Capital Index (MSCI) and estimated risk premia, develop CAPM or APT multifactor[20] estimates of the cost of capital specific to the equity markets of the nation of interest.

(b) *Observed Risk Premia of Government Debt*: This second approach reviews historical bond yields and short-term interest rate differentials of the outstanding debt obligations of sovereign nations. Under this approach, bond yield differences stated in real terms, constitute risk premia and represent common risk differences that can be applied to the financial assets sourced to the public and private entities of, again, the nation of interest.

(c) *Credit Scores Differences*: Entities that provide financial services such as *Institutional Investor* periodically conduct surveys of traders involved in the assessment of capital risks. Through these surveys, a consensus risk assessment and associated credit rating is developed. In turn, the composite credit rating is used as a basis to explain real debt costs and historical market returns. The resulting model provides

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[20] APT refers to *Arbitrage Pricing Theory*. Originally formulated by Stephen Ross in 1980, APT and multi-factor models are often viewed as extensions of the CAPM framework, within which CAPM Beta constitutes a one-factor approach. Multi-factor models such as the Fama-French 3-factor model have been shown to better explain historical market returns than the now classic CAPM framework.

a basis to estimate risk premia, given the observed credit rating scores obtained from the surveys. The credit scores of global credit rating agencies can be correlated with observed real interest rates.

(d) *Relative Risks of Equity Market Returns*: Indexes of historical market returns for exchanges of emerging nations are formulated. The statistical variance of the index (market returns) serves as the appropriate risk metric. The variance (or standard deviation) of market returns of the emerging market exchanges is then normalized with respect to the index of a major equity market exchange, such as the S&P500. The result is a relative value of the average equity market for various emerging markets, where the values vary around (are somewhat above) unity. The final step is to multiply the observed equity risk premia for the major exchange by the calculated values of relative statistical variances for the emerging markets. These adjusted equity premia are then coupled with low-risk sovereign debt yields for the markets of interest.

68. In short, there are several plausible ways to potentially address the question of the existence and magnitude of sovereignty risks. While all four approaches are seemingly viable, some methods are likely to provide more reliable estimates of true underlying country risks than others.[21]

X. METHODOLOGY: ESTIMATION OF THE COST OF EQUITY

69. It is useful to reiterate three essential points identified earlier. First, the cost of equity of the firm—and of investors in the firm—is a function of perceptions of risk, the demand for and supply of capital, and expectations of inflation. Second, the cost of common equity of the firm is equal to the opportunity cost of capital incurred by common shareholders of the firm contemporaneously, though the experience of long-term history guides the assessment of opportunity costs. Third, the cost of equity of the firm is equal to the expected market rate of return on alternative investments of comparable risks available to shareholders—*i.e.*, the opportunity cost of capital—within a contemporary timeframe.

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[21] In particular, the nation-specific equity market risk premia approach appears to provide counterintuitive and inconsistent results for some emerging markets and regions.

70. For two fundamental reasons, the determination of the opportunity cost rate for equity capital is both challenging and somewhat removed from the analytical procedures used to determine the cost of debt. In the case of debt, both the market price and future expected cash flow returns associated with debt securities are generally observable, by inspection. Thus, the net expected yield to maturity, which reflects the opportunity cost of capital to holders of debt, can be determined directly. This *is* the market rate of return, *ex ante*. For purposes of determining the overall utility rate of return, however, the cost rate of long-term debt is that which is set at the time of debt issuance in primary financial markets.

71. In contrast, expectations of investors about the prospective cash flows and market returns on common equity cannot be observed directly, and must be inferred using estimation procedures. In addition, the allowed equity rate of return is typically set according to the current and expected cost of capital, though much of the equity investment was committed in many years past. That is, the cost of equity may change over time significantly—and rapidly—as market conditions change even though the original equity contribution to total invested capital remains constant.

72. In summary, the cost of common equity can only be discerned through the proper and careful application of well-established methods that are provided by modern finance theory. These methods involve procedures to determine the cost of equity capital via the estimation of key parameters.

73. As mentioned earlier, the basis for my recommendation for the rate of return on equity for the Company is based on the equity cost of capital as determined through the application of four estimation methods. The methods include variants of the constant growth *Discounted Cash Flow* model ("DCF"), and the *Capital Asset Pricing Model* ("CAPM"). These classical approaches are commonly recognized within modern finance theory and are readily utilized for purposes of capital valuation. These two formal models of the cost of capital are augmented by an assessment of *Realized Market Returns* for utility and non-utility companies of comparable risks, and estimates of cost of capital, as inferred through the *Risk-Premium* methodology. While other technical methods are available—notably, multi-factor models—the four approaches utilized in the Cost of Capital Study are widely accepted and

used for purposes of capital valuation. Each of the methods is discussed below.

74. The constant growth Discounted Cash Flow model was originally developed by Myron Gordon in 1957, and was advanced during the early 1960s. In its classical (one-stage) form, the derived DCF model defines the cost of capital as the sum of the adjusted dividend yield, and expectations of future growth in cash flows to investors including dividends and future appreciation in share prices. The classical DCF model is as follows:

$$k_{e,j} = D_{0,j}(1+E(g_j))/P_{0,j} + E(g_j)$$

with,

$k_{e,j}$ = cost of equity capital, asset j

$D_{0,j}$ = current dividends per common share, asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share, asset j

75. The one-stage form of the DCF approach is an elegant and intuitively tractable model with two terms, a mathematical result derived from the constant growth present value model. A cursory review of historical returns on equities suggests that, to a substantial extent, differences in the observed internal returns to capital, as well as expectations of future returns as expressed by security analysts, contribute to realized market appreciation as well as total returns to capital. It is, moreover, plausible that the *expected path* of future returns harbored by investors may assume a pattern of non-constant growth. This means that, at least under some market conditions, the constant growth form of discounted cash flow may not represent investor expectations of growth with sufficient accuracy. Arguably, other forms of DCF may serve as better approximations of investor expectations.

76. A plausible means to better model expectations of varying future growth might be with stochastic models, where the path of returns and growth is a function of time, with a random component. However, stochastic models introduce considerable complexity. As a first-order approximation to stochastic processes, multiple-step growth models known as multi-stage DCF can serve nicely. Essentially, multi-stage DCF is a variation of present value theory which postulates that future returns assume a pattern of several growth steps or stages. While any number of stages of constant growth is possible, two or

three stages are typically applied. In stylized fashion, the Three-Stage DCF model is shown below:

$$P_{0,j} = (1+g_j)/(k_{e,j}-g_j)\{D_{0,j}(1 - F^5_j) + D_{5,j}(F^5_j - F^{10}_j) + D_{10,j}(F^{10}_j)\}$$

with,

$k_{e,j}$ = cost of equity capital, asset *j*

$D_{t,j}$ = current and future dividends per common share, asset *j*

$E(g_j)$ = expected growth in future cash flow returns to investors, asset *j*

$P_{0,j}$ = current price per common share, asset *j*

F_j = $(1+E(g_j))/(1+k_{e,j})$

77. As shown in the above formulation for the Three-Stage DCF, discounted prospective cash flows are represented by three terms that incorporate the factor "F," each of which is differentiated by expected growth (*E(g)*). In the Three-Stage approach or the multi-stage approach, investor expectations of future growth are differentiated among these three timeframes. Unlike the single-stage DCF approach, the estimated cost of equity capital solution to the multi-stage model (the discount rate *k*) is obtained through a mathematical search procedure that iteratively solves for the discount rate that balances the left- and right-hand-sides of the equation.

78. The CAPM was developed by William Sharpe (1961) and John Lintner (1964). CAPM was derived from mean-variation analysis and, in particular, portfolio selection developed by H. Markowitz (1952). The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk-free returns and an *adjusted risk-based return.* Surrogates for risk-free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. Some applications of CAPM, long-term debt. As a general rule, the cost rates for and market returns of government debt obligations are accepted as "riskless assets" and thus serve as appropriate proxies for risk free yields.

79. The adjusted risk-based return is based upon three factors: 1) the covariation of the returns to the asset and that of markets for risky assets, 2) the statistical variance of returns of the market for risky assets, and 3) the *difference* between expected overall returns on risky assets, and risk-free returns. The third parameter is referred to as the excess return, and is equal

to the difference between the overall returns to risky assets for the market as a whole, and the risk-free return rate. The CAPM is shown below:

$\boldsymbol{k_{e,j} = r_f + B_{jm} * (r_m - r_f)}$ where $B_{jm} = \sigma_{jm} / \sigma_m^2$

with,

$k_{e,j}$ = cost of equity capital for risky asset j, stated in percentage terms

r_f = risk-free rate of return

B_{jm} = ratio of the covariation between risky asset j and the market as a whole, σ_{jm}, and the variance of market returns, σ_m^2

r_m = expected rate of return on equity markets, as a whole

80. The efficient market hypothesis plays an essential role in the determination of the equity cost of capital. Specifically, the working assumption, which is largely confirmed by empirical analysis, is that the highly developed capital markets of western economies are fairly efficient. This means that the supply and demand for risky financial assets, as reflected in bid and asked prices to buy and sell common equity shares, result in financial assets being traded at price levels where *rates of return above the cost of capital cannot be systematically realized.* Above-normal returns—returns above the cost of capital—are realized only randomly. Essentially, the opportunities to systematically realize returns above the underlying cost of capital are exhausted by the competitive market process.

81. Estimating the cost of capital, though not trivial, can be fairly straightforward, and the four approaches employed in the immediate Study—DCF, CAPM, Historical Market Returns, Risk Premium—provide a useful analytical framework from which the cost of equity can be inferred. The risks to investors in various sectors of the energy services industry cannot ever be known directly; risks and hence the implied cost of capital can only be inferred. Specifically, the determination of useful estimates of the cost of common equity capital within each method requires a discerning application of theory through careful analysis, such as that presented herein. In particular, the determination of the cost of equity capital faces two overarching challenges, as follows:

    (i) the selected and applied methods herein are inherently forward looking, where future expectations are gauged from history. Hence, the results are highly dependent upon useful estimates of investor expectations about future market performance. However, future expectations are drawn from history and underlying relationships among historical information data. Arguably, all that we know—indeed, all knowledge—is based on observed facts (historical data) and perceptions of relationships among data; and,

(ii) key underlying assumptions include efficient markets and rational behavior of investors such that all opportunities for above- and below-normal returns to capital are exhausted on an expected value basis. In short, capital markets value financial assets at the implied opportunity costs of capital, given investor perceptions of risk.

82. It is useful to mention that the notion of *risky assets* can apply to any real or financial asset wherein the prospective returns from holding the asset are uncertain. Risky assets include commodity contracts, financial property rights, financial derivatives, and real assets such as power delivery and generation facilities of electric utilities. Risk assessment and option theory, moreover, can be applied to the analysis of unbundled services, such as electricity transmission development plans. Within the context of this discussion, however, risky assets refers to financial obligations of firms—debt holders and common shareholders—and asset values refers to prices of common stock as observed on major stock exchanges.

83. Measurements of *Realized Market Returns* and risk metrics are increasingly used as a basis to assess plausible returns in the future. As discussed, efficient markets suggest that *all* financial assets are priced at levels such that the *expected* future returns of individual assets are equivalent to the underlying opportunity cost. Thus, if historical returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. In this respect, the *Realized Market Returns* methodology can be viewed as a market-based approach of Comparable Earnings, and thus fully satisfies the *Bluefield* and *Hope* criteria. More specifically, realized market return for a period is defined as:

$$R_{j,\,t-t\text{-}1} = (P_{j,\,t} + D_{j,\,t-t\text{-}1} - P_{j,\,t\text{-}1})/P_{j,\,t\text{-}1}$$

with,

$R_{j,\,t-t\text{-}1}$ = return realized within the interval $t-t\text{-}1$, for financial asset j

$D_{j,\,t-t\text{-}1}$= dividends paid during the interval $t-t\text{-}1$, for financial asset j

$P_{j,\,t,\,t\text{-}1}$ = market value of financial asset j, at t and $t\text{-}1$

84. The key to successfully applying this third approach is identification and measurement of historical returns in a manner that reasonably reflects expectations of investors about the future outlook.

85. The *Risk Premium* methodology is based on ordering of types of financial assets according to yields—and thus risks—as observed historically. This ordering according to risks is a natural and inevitable result of competitive financial markets. Essentially, because risk is costly, higher costs must be offset by higher returns. While the Risk Premium approach is not based upon a conceptual model and derived form, the application utilizes CAPM. The analysis of the risk premia among classes of risky assets provides a means to infer the underlying opportunity cost of capital. The underlying concept of the risk premium approach is that *differences* in perceptions of risks among financial assets such as equities and debt are revealed in differences between the historical market returns. The historical differences between equity and debt returns—*i.e.,* risk premia—can thus serve as estimates of required compensation for risk assumed by investors over future timeframes. The approach begins with expected inflation, and then takes account of the expected cost of short- and intermediate-term debt, equity risk premia, risk differences between equity markets as a whole and utilities as measured by CAPM beta, and size-related risk premia where appropriate. While risk premium models can assume various forms, the immediate application of the Risk Premium approach is codified as follows:

$$k_{e,j} = r^{st}{}_{f} + rp_{int-st} + rp_{m-nlt} + rp^{CAPM}{}_{y-m} + rp^{s}{}_{j}$$

with,

$k_{e,j}$ = cost of equity capital for risky asset j, stated in percentage terms

$r^{st}{}_{f}$ = risk-free rate of return, for a short-term asset

rp_{int-st} = risk premium for intermediate-term asset *int* with respect to a short-term asset

rp_{m-int} = risk premium for equity market m with respect to an intermediate-term asset

$rp^{CAPM}{}_{y-m}$ = risk premium for industry y with respect to equity market m, where y refers to the relevant industry sample

rp^s_j = size-based risk premium for risky asset j[22]

86. Application of the Risk Premium approach contains two potential pitfalls, as follows:

(i) the opportunity cost of common equity capital, stated in nominal terms is sensitive to the demand for and supply of capital; and

(ii) risk premia among debt and equity instruments are also quite sensitive to expected inflation. Thus, Risk Premium analysis must account for expected inflation in the future. That is, the underlying rate of inflation and conditions of the historical period over which risk premia are estimated must match those of the expected conditions of the relevant period over which the common equity recommendation is being applied, and over which retail electricity prices are being set.

XI BUSINESS AND FINANCIAL RISKS: BARBADOS LIGHT AND POWER

87. Setting forth recommendations regarding the appropriate rate of return is not a mechanical model-driven result obtained in isolation. An understanding of business context to gauge capital risks is essential. Risk assessment should take account of the generic risks attending entities involved in energy markets and electricity service providers, as well as idiosyncratic risks associated with specific business context. Accordingly, analysis of the cost of capital, for purposes of setting the rate of return, should be fully informed and sensitive to the facts defining the relevant generic risks and the idiosyncratic risk profile of the Company.

88. Generic business risks attending the cost of capital for electricity service providers are strongly interdependent and will be briefly mentioned. In the contemporary environment, electric utilities face rapidly rising costs at a time of general tightening of the supply-demand balance, ongoing advances in electricity demand, and in the U.S.A, rapidly heightened requirements for environmental compliance. Increased upward cost pressures, in turn,

[22] Size-related risk premia are, as a general rule, relevant within the context of the Capital Asset Pricing Model. Specifically, the CAPM-based estimates of market returns appear to systematically understate the cost of equity capital for small-sized stocks. Size-related risk premia may not be relevant or appropriate in other model contexts.

precipitate increased resistance to price increases and scrutiny by stakeholder groups of the prudency of utility resource decisions and the reasonableness of cost levels. Rising cost pressures are a particular concern for the Company in view of the surge in prices for primary fuels in early 2008, driven in part by the sharp decline in the U.S. currency with respect to other major international currencies.

89. All too often, cost pressures from the perspective of investors and utility managers arise as a result of issues of timeliness of rate relief, and less than full recognition by regulators of legitimate costs. The end result is a shortfall of revenue with respect to cost levels, manifest as increased variation in operating income, lower interest coverage on debt, and earnings that may not cover investors' cost of capital.

90. The Company is a comparatively small, full service integrated electric utility. On the basis of size alone, the Company carries an element of risk additional to that of larger utilities delivering an equivalent range of services. As discussed below at considerable length, empirical evidence suggests that, within the context of diversifiable financial risks defined by the CAPM framework, the cost of capital rises with decreases in the capitalization. Essentially, all other factors constant, small capitalization entities have higher non-diversifiable risks than larger companies. Additionally, investors may harbor higher risks because of uncertainty of market valuation attributable to limited information.

91. As an island power system, the Company and its investors are exposed to special dimensions of risks relative to utilities in larger economies. Island electric power systems implicitly harbor higher operating risks. Specifically, the Company cannot immediately draw upon neighboring power systems in the case of a major equipment failure for either high voltage transmission or for generation reserves. Accordingly, the Company must carry fairly high levels of reserves for generation services. Furthermore, small-sized electric systems enmeshed within larger continental power systems and markets can diversify generation operational risks and costs by carrying a comparatively large number of small-scale ownership shares in multiple facilities. In comparison, the Company's physical stock of generation resources is relatively indivisible. Capital indivisibility of generation adds to operational

risks in obvious ways. In addition, however, capital indivisibility implies that generation additions, which come about frequently in view of the fairly high rates of growth of Barbados' electricity demand, are brought to commercial operation in rather lumpy increments.

92. In the case of power delivery, the Company is not embedded in highly integrated meshed power systems of the major continents; other factors constant, the implicit level of reserves within power delivery for the Company must be at higher levels with respect to its counterparts in Continental power systems. Moreover, the Company is unilaterally exposed to the damaging impacts of large storm systems that, from time to time, can threaten Barbados and the Company's power delivery systems. While the Company is partially insured for these events of major magnitude, the possibility of such events precipitates technical and institutional uncertainty that translates into risk regarding the continuity of revenue and the future returns to capital. Similarly, fuel supplies for the Company cannot be readily diversified across fuel types, multiple sources, and transportation modes, as they can for continental systems.

93. In summary, then, one must conclude that, from the perspective of investors, the Company is not readily able to diversify capital risks to the same degree as utilities in other continents.

XII. INTEREST RATES TRENDS

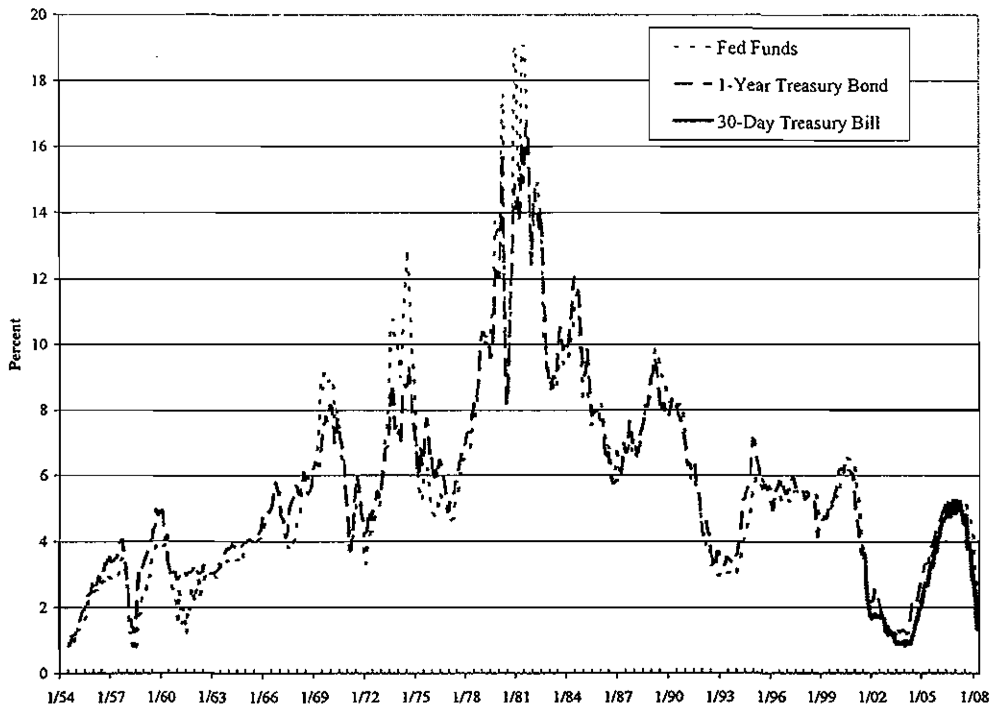
94. As mentioned earlier, long-term interest rates follow current and expected inflation to a substantial extent, whereas short-term interest rates are sensitive to both inflation and monetary policy geared to preserving real economic growth and stability. Indeed, a major international development during the mid-1990s has been much more disciplined money supply that has obtained a corresponding decline in worldwide inflation. Because less inflation is needed to compensate for the loss in purchasing power resulting from the escalation in money supply, interest rates have declined significantly.

95. In any case, it is useful to review the interest rate experience over both the long-term history and contemporary timeframes. Shown below in Tables E to H, are selected short- and long-term interest rates for the periods 1954-2007

and 2000-2007. Short-term rates are represented by U.S. Fed Funds interest rates, and the yields for 30-Day treasury Bills and 1-Year Treasury Bills; and long-term rates are represented by the yields for AAA-rated corporate bonds, BAA-rated corporate bonds, 5-year U.S. Treasury Bonds, and 10-year Treasury Bonds.[23]

TABLE E

SHORT-TERM U.S. INTEREST RATES, 1954 - 2007



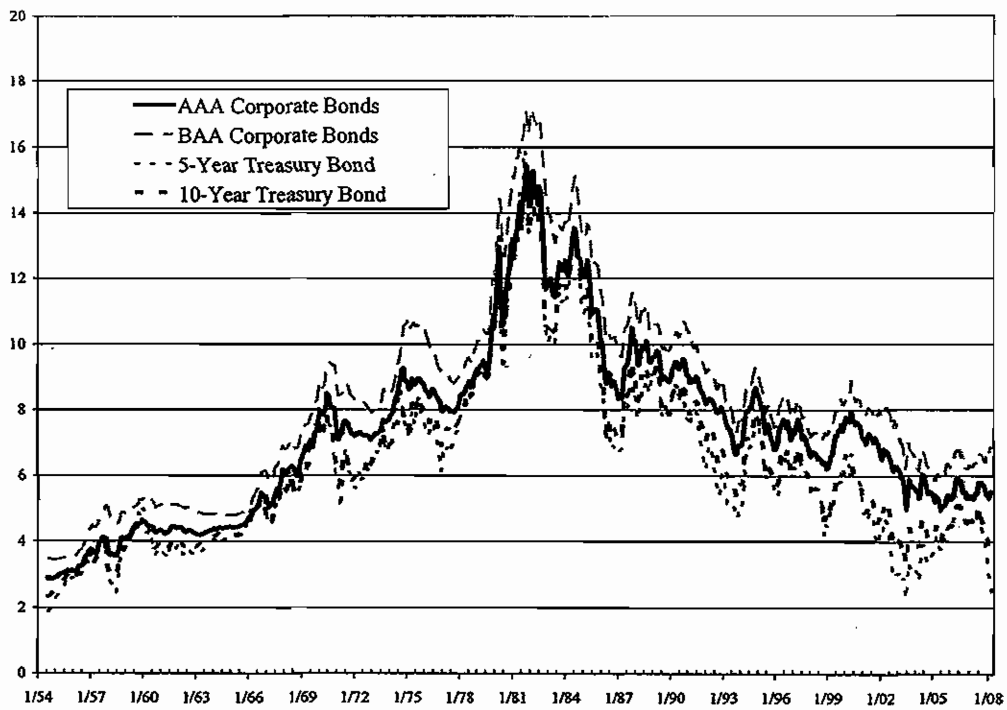
96. The remarkably low short-term interest rates at the beginning of the period, the mid-1950s, were a direct result of very low inflation. As can be observed, short-term interest rates prior to the early 1970s resided below 6% except for the notable but short-lived excursion of 1969-70. In the 1970s and continuing

[23] There is a wide range of debt mediums—and thus interest rates—across U.S. financial markets, including prime rate commercial bank loans, rated and non-rated commercial paper, constant maturity U.S. Treasury bills and bonds, Fed Funds and London Interbank Offer Rate loans of various durations, corporate bonds including debenture and mortgage debt, municipal bonds, home mortgages including variable and fixed-rate loan vehicles, and a range of securitized debt which is sometimes referred to a structured finance.

through the recession of 1990-91, the U.S. experienced substantially higher short-term rates, typically in the range of 8-10%, with the exception of the 1979-1983 timeframe, where short-term interest rates ran briefly above 16% during an environment of highly restrictive monetary policy geared to reducing the high rate inflation at the time. Not surprisingly, this era of U.S. monetary history was also an era of much higher inflation, particularly during the late 1970s-1985, with gradual declines thereafter. From 1991 forward, short-term interest rates have generally receded back to sub-6% levels although excursions above this level can be observed.

TABLE F

LONG-TERM U.S. INTEREST RATES, 1954 - 2007



97. The pattern of long-term interest rates largely parallels that of short-term rates, as discussed above and shown in the previous graph. Not surprisingly, the interest rates on corporate debt consistently reside above those of U.S. Treasury debt. Most interesting, however, is the spread between corporate and treasury debt. The interest rate differences between corporate and treasury debt has increased significantly during the post-1991 period when compared to the period of comparable rates of inflation, 1954-1969.

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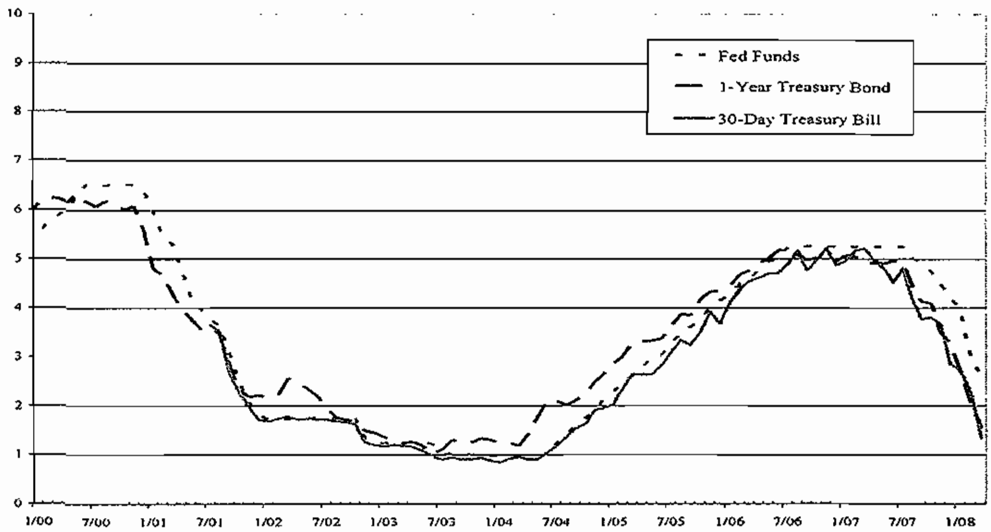
TABLE G

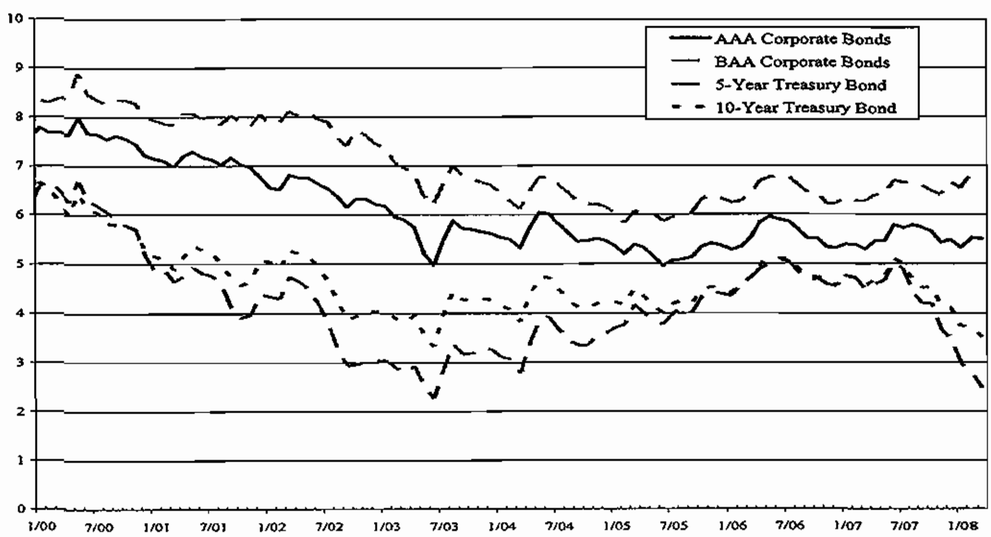
SHORT-TERM U.S. INTEREST RATES, 2000 - 2007



98. Turning to the more contemporary period, two features are noteworthy. First, short-term interest rates, driven by expansionary monetary policy, dropped to unprecedented low rates of less than 2%, and remained at that level for the period 2002-2004. Second, beginning in late 2007, short-term rates declined precipitously, again driven by an accommodative monetary policy quickly implemented in response to the sudden decline in the level of economic activity.

TABLE H

LONG-TERM U.S. INTEREST RATES, 2000 - 2007



99. *The essential feature of long-term interest rates currently is the increase in* the interest rate spread between corporate and U.S. treasury securities, particular for BAA bonds. Whereas long-term treasury yields, following short-term interest rates, have declined by 1.5-2.5 percentage points since July 2007, corporate interest rates show little movement. Moreover, corporate BAA debt yields have risen, despite the general decline in interest rates, as a result of higher perceived default risks. No doubt, the relevant development occurring just recently within the U.S. and, to a lesser extent in international debt markets, is the sharply higher default risks associated with the structured *financial vehicles (asset-based financing) of various types.*

100. In the case of Canada, growth in real economic activity and productivity has assumed a general upward path since about 1991, commensurate with a gradual move favoring economic liberalization in the form of privatization and mitigation of regulatory burdens. In particular, the Bank of Canada has implemented more disciplined monetary policy that, in general, have resulted in reduced levels of inflation and corresponding decreases in short- and long-term interest rates, as revealed in Table I below.[24]

TABLE I

CANADIAN TREASURY YIELDS (%)

Year	3-Month Bills	2-Year Bonds	10-Year Bonds
1982	13.7	12.9	13.7
1990	12.8	11.4	10.8
1991	8.7	8.8	9.4
1995	6.9	7.2	8.1
2000	5.5	5.9	5.9
2005	2.7	3.2	4.1

XIII. <u>OVERALL EQUITY MARKET RETURNS AND RISK PREMIA</u>

101. Market rates of return and equity risk premia are positively related to productivity and general economic performance. The economies of North

[24] The historical interest rates shown for 2000 and 2005 confirm the risk-free Canadian cost rate of 4.64% (monthly, 2002-2006) utilized in the CAPM analysis for the Canadian samples 1 and 2, as discussed below.

America are fairly well positioned to realize and sustain substantial if not high rates of growth in productivity and real output, along with near full employment and modest inflation over the foreseeable long-term future.[25] Investors generally share this consensus view and, accordingly, the analysis herein draws upon realized overall market rates of return and interest rates as representative surrogates for the near-term future, and over which retail prices are likely to be in place. The average percentage return for U.S. equity markets overall, as gauged by the S&P 500 index, was 12.8% from 1970 through 2006,[26] which is the period of representative levels productivity growth in view of future potential. The 12.8% overall market return level over 1970-2006 is used as the expected level of future returns to equity markets within the CAPM analysis for U.S. markets, with commensurate levels of market risk premia of 8.07%. Moreover, this longer-term experience is consistent with contemporary productivity levels and realized returns to equity markets. For the U.S. economy, the average rate of observed productivity growth for the period 1970 forward resides well within the range identified above, and covers a very slow-growth period—the late 1970s to early 1980s—and the high productivity growth of 1995 through 2003. Productivity growth appears to have receded somewhat in recent years from the exceptional levels obtained during '95-'03 timeframe. Given the relationship between market returns and productivity and other conducive factors, and because overall productivity growth over this timeframe is a reasonably close match to the expected range of productivity in the future (see Martin Baily, Dale Jorgenson)[27] investors have reason to expect annual level of overall market returns to approach 11.5 to 13.0%. For U.S. equity markets, realized market returns for the period 1970-2006 comport well with realized market returns over extended periods, as shown below in Table J, with little change in sight.

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[25] Generally speaking, Canadian productivity will likely remain slightly less than that of the U.S.

[26] Contemporary high rates of productivity growth were obtained through the widespread adoption of information technologies including computers, common communication and software platforms that facilitated efficient information transfer, leading to a broad range of operating benefits across the U.S. economy.

[27] Baily, Martin N.; "U.S. Productivity," *Economic Perspectives*, American Economic Association, 2003; and Jorgenson, Dale W., Ho, Mun S., Samuels, Jon D., Stiroh, Kevin J., *Industry Originals of the American Productivity Resurgence*, June 2007.. While Baily suggested that U.S. productivity—in this case, measured as labor productivity—may trend toward 2.7% or so, he has more recently discussed the recent slowdown in U.S. productivity.

TABLE J

Total Market Returns through 2007		
Number of Years	Initial Year	Realized Historical Annual Return (%)
81	1926	12.30
70	1937	12.30
60	1947	13.20
50	1957	11.90
40	1967	12.30
30	1977	13.60
20	1987	13.00
10	1997	12.00
Average, '67-'07		12.7
Average, '77-'07		12.9

102. Similar reasoning—namely, the causal link of productivity growth to overall equity market returns and risk premia—leads to a Canadian risk premium of 6.63% over the relevant timeframe, 1991-2006. As alluded to in the above discussion, these levels of risk premia are consistent with the level of contemporary productivity growth and cost of capital for Canada[28], particularly when coupled to comparatively low levels of inflation and disciplined monetary policy—key contributing factors to realized equity market returns. Indeed, Canada transitioned to a regime of lower inflation and interest rates during the 1997-1999 timeframe and has sustained this more favorable economic environment since then.

103. However, overall economic performance and long-term growth can be attenuated by events of a transitory nature and by various long-term processes that can contribute to capital risks such as the costs to maintain environmental quality, or increasing worldwide cultural friction. An immediate example is the recent decline in credit market liquidity. Finally, it is important to mention the impact of government fiscal policy and global demand for capital on interest rates. As mentioned, the cost of capital is a function of the

[28] This 16-year period experienced a market rate of return of 11.26%, which closely approximates the observed realized returns of 11.34% for the 2002-2006.

demand for and supply of funds, and we expect U.S. and world demand for capital to remain at high levels, thus placing steady upward pressure on interest rates. As a result, long-term interest rates are likely to remain at or near current levels, which are close to historical experience despite recent declines in short-term interest rates.

XIV. COMPARABLE RISK COMPANIES: COST OF EQUITY

104. As defined by the **Bluefield** and **Hope** decisions of the U.S. Supreme Court, *a public utility (to paraphrase), is entitled to a rate of return on shareholder* capital committed for the convenience and necessity of the public equivalent to that realized by companies in other businesses of comparable risk. Thus, the task at hand is comparability: to identify the relevant markets, and to then select companies of comparable business, regulatory, and financial risks to those of the Company. Estimates of the cost of equity are obtained by applying the cost of equity methods to the sample companies, with trading experience on the major exchanges of the North American Continent.

105. For several reasons, the study cannot readily draw upon, at a technical level, the capital market experience of utilities and companies in the Caribbean for *purposes of capital valuation. The Caribbean exchange-traded capital* markets, which effectively consist of the Exchanges for Barbados, Jamaica and for Trinidad and Tobago, have comparatively low levels of liquidity with shallow trading activity from which to estimate prospective market returns and risk premia. Second, the exchange listings contain few market-traded infrastructure entities from which to assemble a comparable risk utility sample—which is necessary in order to ensure that the study results conform to the Fair Rate of Return principles defined above. Third, the common stock trading experience of these exchanges is unusually thin, which would impose special analytical procedures on the study.

106. Accordingly, the study approach is to estimate the cost of equity for samples of utilities with equities that trade on the major exchanges of North America *(U.S. and Canada), and to adjust the cost estimates for utilities of the* Continent for the risk premium (cost rate difference) between Barbados and the Continent. An empirical estimate of the risk premium, which can be referred to as sovereignty risk, is detailed below in the section entitled *Cost of*

Equity Capital and Sovereignty Risk. However, the sovereignty risk premium can also be gauged by comparing the expected real risk-free interest rate (rate of return) on the debt of the Central Banks of Barbados and the U.S., as shown in Table K.[29]

TABLE K

RISK PREMIUM, BARBADOS (BB) WITH RESPECT TO U.S.

2005 Issues, Central Bank of Barbados		
Bond Issue Date	Bond Maturity Date	Coupon Interest Rate (%)
14-Feb	31-Mar-11	5.00
27-Jun	30-Jun-25	7.25
1-Sep	31-Mar-07	5.25
26-Sep	30-Sep-17	7.00
28-Nov	30-Sep-14	7.25
28-Dec	31-Dec-25	7.25
Interest Rate of BB Issues Maturing Beyond '11		7.19%
2005 Inflation, Barbados		3.86%
Real Risk-Free Interest Rate, Barbados		3.32%
Interest Rate, U.S. 20-Year Bonds		4.65%
Expected Inflation, U.S.*		2.68%
Real Risk-Free Interest Rate (TIPS), U.S.		1.97%
Risk Premium, BB with respect to U.S.		1.36%

* Difference Between U.S. 20-Year Constant Maturities and TIPS (Treasury Inflation Protected Securities) Interest Rate

107. Nonetheless, the study draws on the universe of equities of the U.S. and Canadian capital markets as a starting point from which to select comparable risk utilities and companies. Once selected, we then estimate the cost of

[29] Also, a more contemporary estimate of sovereignty risks was drawn. Based on yields for Treasury securities traded in secondary markets, similar levels of sovereignty risk premia were discerned in the updated analysis. Further, I would infer that sovereignty risk premia benchmarked to U.S. securities are likely to have expanded in view of the flight to quality, beginning in mid-September 2008.

common equity for the sample(s) of comparable companies. A key distinction regarding comparability is market size. As recent empirical evidence convincingly demonstrates that, predominantly because of information inefficiencies and uncertainty, the cost of capital rises as firm size declines all other factors held constant.

108. For the samples of U.S. companies, we have drawn heavily—though not exclusively—from a set of data and information sources including Value Line data banks, Ibbotson Associates (Morningstar), and also the web-based services of Yahoo Finance, UBS Financial Services, and Zacks Financial Services. With few exceptions, the equity shares of the sample are traded on the New York Stock Exchange and the NASDAQ exchange, which originated from the over-the-counter trading procedures put in place by the National Association of Securities Dealers in years past. For equities listed on the exchanges, an array of financial data, business descriptions and classifications, historical price experience, and various diagnostic statistics of interest are reported. The sample of Canadian companies is drawn from utility companies listed on the Toronto Stock Exchange, referred to as TSX.[30]

109. From the U.S. market portfolio we proceed to develop two utility company samples and a comparable risk non-utility sample. The first sample, Mid-Sized Electric Utilities (U.S. sample 1) is limited to retail electricity service providers that have modest yet significant levels of market participation and, with the exception of size-related capital risks, are of comparable risk to that of the Company. The second U.S. utility sample is referred to as the Moderate-Sized U.S. Gas Distribution Utilities (U.S. sample 2), and is composed of retail natural gas service providers. Our studies demonstrate that, as a practical matter, the level of capital risks and thus the opportunity

[30] The equity listings of NYSE, NASDAQ, and TSX very clearly do not constitute the full set of investment possibilities. Indeed, some 75 stock exchanges currently exist worldwide. Arguably, some combination of the Morgan Stanley Capital Markets (MSCI) plus exchange indexes of the North American equity markets is a more complete representation, when assessing the performance of equity markets at a summary level, which is necessary in the case of CAPM, Risk Premium, and also Arbitrage Pricing Theory-based methods. However, the North American equity markets, as represented by the many listings on these three exchanges, are highly liquid. Accordingly, movements and performance of the indexes for the North American markets closely parallel movements of other world indexes, though differences are observed as a result of currency exchange rate movements, unanticipated random social and physical events within regions, and significant changes in expectations of economic performance. In addition, the North American markets, unlike worldwide exchanges, carry equity listings for numerous utility companies.

cost of capital for the two samples, electric utilities and natural gas utilities, is comparable. For purposes of determining the equity rate of return requirements of the Company, the study also draws a third U.S. sample, referred to as Comparable Risk Non-Utility Companies (U.S. sample 3). Our methods tend to demonstrate that, particularly within contemporary capital markets with high levels of international capital flows, comparable risk is the predominant selection criterion. Line of business appears to have only a modest level of relevance to cost of capital, once the comparable risk criteria are satisfied. Thus, samples can be drawn from a broad range of business fields, generally speaking.

110. The determination of the first sample, the mid-sized electric utilities, involves two steps. The first step is to conduct an initial screen according to the predefined selection criteria. As mentioned, these criteria are as follows:

(a) *Liquidity*: companies that are of modest size but yet have sufficient market presence and participation to ensure sufficient market activity and transaction volume;

(b) *Business Line*: companies whose primary business line is retail electricity services; and,

(c) *Reasonably consistent financial performance.*

111. To determine U.S. sample 1, the study begins with 42 modest-sized entities within the U.S. electric utility and energy companies. For cost of capital analysis, twenty electric utility companies are selected from this initial set, where the criteria for selection are completeness and consistency of reported financial information and market data, and also electric utility services as the primary business line.[31] Some of these 20 electric companies have involvement in non-electric retail business lines including natural gas. It is virtually impossible these days to assemble a sample of companies that are exclusively in the retail electric business—sometimes referred to as a *pure play*. However, the U.S. electric utility sample is composed of entities that

[31] The increased openness of U.S. electricity markets in recent years, including market entry as well as relaxation of financial restrictions, has resulted in an expanded range of business activity. Today, entities within the electricity services industry are, for example, involved in oil and gas exploration (MDU Resources), real estate (Pinnacle West), and significant non-electricity energy services (Integrys Energy). Arguably, Integrys Energy should be listed with the U.S. natural gas industry as it has substantial natural gas pipeline and distribution business lines in addition to two electric utility subsidiaries including Wisconsin Public Service ("WPS") and Upper Peninsula Power (UP Power).

have, with few exceptions, a dominant share of business activity within electric power generation and delivery.[32] This new diversity should not matter, at least on the surface, if the sample is determined on a basis of comparable risks. Indeed, endeavors to diversify risk over alternative business lines tend to reduce variation in earnings, variation in internal cash flow, and variation in market returns, thus reducing overall investment risk and the cost of capital.

112. From this set of 20 companies, eleven electric utilities are selected according to the comparable risk criteria. The second selection step in determining the electric utility sample applies risk criteria. These criteria include four dimensions, or metrics:

(1) Equity Participation in Total Capital;

(2) Coefficient of Variation in Earnings per share over five and ten years;

(3) CAPM Beta which, as discussed above, is the ratio of the covariation of the market returns of a specific stock of a company and the market as a whole, and the statistical variance of the returns of the market; and,

(4) Variation in Market Returns, which is measured as the coefficient of variation of monthly market prices—essentially, an index of volatility in market value (market capitalization).

113. Those eleven electric utility companies with risk metrics that generally fall within one standard deviation of the average for the sample of electric utilities as first drawn or are reasonably close to the metrics for the Company are retained in U.S. sample one (mid-sized U.S. electric utilities). It is these utility companies that, by this arguably objective approach, satisfy the criteria of comparable risks and thus the U.S. Supreme Court guidelines regarding fair rate of return contained within the **Bluefield Waterworks** and **Hope** decisions.

[32] Of the companies incorporated in the final set of proxy companies used to estimate the cost of capital, two members of the sample stand out with substantial non-electric business: Madison Gas and Electric Company (MGE) has substantial natural gas distribution operations, and Hawaiian Electric (HE) which has a large financial services business line.

114. The market capitalization of these companies, measured by common shares outstanding and market prices during 2006, ranges from $82 million for Florida Public Utilities Company to about $4.1 billion for SCANA (South Carolina Electric and Gas), stated in USD. The non-weighted average size of U.S. sample 1, the electric utilities, is about $1.8 billion USD.[33] CAPM Betas have risen over time, suggesting significantly increased capital risks associated with energy markets, including electric service providers.

115. The mean-variation theory on which the Capital Asset Pricing Model is based suggests that risk metrics other than CAPM Beta do not matter for the determination of portfolios that efficiently trade off risks and potential future return levels. However, empirical *evidence* suggests that a) internal financial metrics such as items 1-3 above are also utilized by investors to value equities, and b) CAPM theory (as with other capital market theories) does not necessarily explain historical market returns particularly well. Thus, it appears that, to a substantial degree, information other than CAPM Beta is also relevant to investors for the valuation of equities.

116. Turning to the moderate-sized U.S. gas distribution utilities (U.S. sample 2) and the comparable risk non-utility companies (U.S. sample 3), the selection process proceeds in similar fashion using criteria equivalent to those employed to determine the U.S. mid-sized electric utility sample (U.S. sample 1). That is, a sample is first drawn on the bases of market liquidity and business line. The initial set of natural gas utilities includes 27 entities that range from $55 million to 2.8 billion USD equity market capitalization in late 2007. From this initial draw,[34] 11 entities are initially selected and, through the application of the risk screen, 8 entities are ultimately selected for use in the immediate cost of capital study. As with the U.S. electric utilities sample, these companies, although of comparatively modest scale by U.S. benchmarks, are all significantly larger than the Company, which implies that the Company has higher capital costs, holding other factors constant. In view

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[33] Not shown but available are the compiled profiles of the sample utilities and non-utility companies, including brief reviews of the business, operating revenues, assets, and operating margins.

[34] The U.S. natural gas industry includes many regional and national distributors of liquid propane and specialty industrial gas products and services, such as Penn Octane Corporation, Suburban Propane Partners, and Continental Fuels Inc.

of the Company's business context, the Company appropriately underwrites its assets with higher equity participation than its U.S. counterparts.

117. The sample of comparable risk non-utility companies is drawn from U.S. non-utility economic sectors. The initial selection criteria were equity market capitalization of less than $750 million USD, equity participation in total capital of less than 0.80, CAPM beta range of 0.40-1.00, and public domain financial data for ten years. These criteria resulted in the selection of 84 entities from well over 3,000 U.S. exchange-listed firms, where the selected firms include food markets, pipe manufacturing, financial services, health services, and a military equipment manufacturer. The application of a random selection procedure culled 27 entities[35] from the set of 84, and ultimately provided 24 entities ranging from $70 to $575 million USD equity market capitalization. The second selection screen—equity participation, CAPM beta, variation in market returns, and variation in earnings per share (internal business risk)—obtain 20 companies that together constitute the comparable risk non-utilities (U.S. sample 3).

118. While the U.S. sample 3 companies have similar overall risk levels to that of the U.S. electric and gas utilities, differences exist across the three samples for individual risk criteria. For example, the non-utility companies have, on average, equity participation of 70%, CAPM beta of 0.72, variation in annual market returns of 5.94%, and coefficient of variation (CV) in earnings per share of 0.37 and 0.45 for 5- and 10-years, respectively. The corresponding values for the electric utility samples are 49% equity participation, CAPM beta of 0.80, 4.00% variation in market returns, and CV in earnings per share ranging from 0.16 to 0.19.

119. The Canadian utilities, including samples 1 and 2, cover Toronto Stock Exchange-listed entities that are classified by the Exchange as utilities. The utility category covers private companies that provide a fairly broad range of infrastructure services including telecommunications, rail transportation, renewable energy, natural gas distribution, power generation, and gas

[35] It should be mentioned that incomplete or anomalous financial data, as reported, caused some randomly selected entities to be substituted with other entities from a nearby location within the total list of 84 entities.

transmission services, in addition to conventional integrated electricity services. Implicitly, this broad range of business and market context appears to imply, for some entities within the category, higher business and operational risks than typical U.S. electric and gas utilities. Accordingly, special caution is used in sample selection. Because of the limits in readily available financial information[36], and because the TSX-listed utility entities are comparatively few, the analysis of the Canadian utilities proceeds differently and is less comprehensive than the analysis performed for U.S. samples 1-3. Moreover, the formal selection procedures discussed above are unfortunately not directly applicable to Canada because of the small number of entities listed as utilities.

120. While some 22 companies are listed as utilities on TSX, half fall out of the selection process because of high-risk business context, uncertain financial performance, or because of high financial market risks, (as measured by CAPM beta). Examples of TSX-listed utilities excluded from the cost of capital study are Great Lakes Hydro (sudden, large decline in earnings), Algonquin Power Income Fund (specialized interest in renewable resources), EPCOR Power equity (holds EPCOR Power; negative earnings), Tellus Corporation (very high CAPM beta), Boralex Inc. (very high CAPM beta; power generation including hydro, wind, biomass, and natural gas cogeneration), ALTEK Power (independent power producer listed on TSX Venture), and Sierra Geothermal.

121. The result of the selection process is 11 Canadian utilities. Canadian sample 1 consists of conventional electric and gas utilities, whereas Canadian sample 2 consists of longstanding and consistently performing utility entities of moderate market risks in pipeline, rail transport, power generation, and telecommunication business lines. Unfortunately, the entities are

[36] Financial data reported by U.S. companies listed on the major U.S. equity markets including NYSE and NASDAQ are reported by the listed entities to the Securities and Exchange Commission ("SEC"). By law, the SEC imposes highly specific financial reporting standards. These data, in turn, are compiled by several financial services companies including Compustat, Value Line, Bloomberg, and others. Thus, compiled financial and equity market information can be readily obtained in non-compiled form directly from the SEC or in a compiled form from services such as these. This is not the case for Canadian companies. While compiled financial information is available through SEDAR, such data are much less complete, thus burdening valuation studies such as this with obtaining financial data in non-compiled form from the web sites of the entities of interest, and by other means.

comparatively large on average, and vary greatly in equity market capitalization. Specifically, the average size of Canadian sample 1 is $6.0 billion CND with a corresponding range of $15.7 to 1.7 billion, whereas the average size of Canadian sample 2 is $4.7 billion CND with a range from $65.5 million to $19.9 billion. The comparatively large size of the Canadian utilities makes the point of the necessity of incorporating size-related risk premia within the immediate cost of equity study.

122. In summary, the estimate of the cost of equity capital of this study involves five samples, including the three U.S. samples—the mid-sized U.S. electric utilities (U.S. sample 1), U.S. gas distribution utilities (U.S. sample 2), and comparable risk non-utility companies (U.S. sample 3); and the two samples of the Canadian utilities (CN samples 1 and 2). The estimate of the cost of capital, and thus the recommended return on common equity, is reflected as an interest rate that, by objective criteria of comparable risks, is the opportunity cost of capital incurred by the common shareholders of the Company.

123. Market Liquidity is a necessary selection criterion, as stated above. The selection process results in generally smaller-sized electric and gas utilities that have sufficient liquidity. However, the selected utility companies are substantially larger than the Company as a general rule. Because the cost of equity capital appears to increase progressively with smaller size, other factors constant, the implication is that the cost of equity capital, as estimated for the two samples, may not fully capture the inherent capital risks incurred by investors of the Company. The topic of size-related risk premia is discussed more fully in the following section.

XV. EMPIRICAL FINDINGS, COST OF EQUITY

124. This section presents the results of the analysis of the cost of equity capital appropriate for the determination of the return on equity for the Company. The first step is to apply the four methods to estimation of cost for the comparable risk peer groups of the Company. However, it is difficult to create a peer group for the Company due to its small size relative to other companies. Because evidence suggests that the cost of capital rises

progressively with smaller-sized entities,[37] the cost of equity estimates derived from the analysis of the peer groups will be systematically low. Also, the estimation procedures, including the selection of the comparable risk peer groups, do not explicitly take account of business context differences—in particular, the isolation associated with the Company's island power system. This analysis explicitly estimates the likely range of sovereignty risk, which is incorporated into the cost of equity capital recommendation.

Peer Group Estimates of the Cost of Equity

125. The analysis draws on recent and long-term historical experience as the basis to determine the cost of equity capital, which incorporates capital risks and future prospects for capital returns. While estimates of the cost of capital are inherently forward looking, the process of estimation draws upon historical assessments of risk and the future prospects for market returns—essentially, the realized returns to investors and savers, as holders of property rights claims to capital in the form of financial assets. Tables L to O below summarize the analysis conducted using the four approaches for the U.S. and Canadian[38] utilities and U.S. comparable risk non-utility companies.

[37] Size-related risk premia, within the context of CAPM analysis, are reflected in higher levels of CAPM Beta with progressively smaller entities. This empirical result is expected. However, it appears that CAPM Beta for smaller capitalization entities, though higher, systematically understates realized historical returns. This second component of the size premium is explicitly recognized in the Risk Premium cost of equity approach used in this study.

[38] The study does not apply the discounted cash flow ("DCF") methodology to the two samples of Canadian utilities because of the limits of reported financial data for a sufficiently long historical period. DCF is also not applied to the U.S. comparable risk non-utility sample because of non-applicability, in view of the sparse dividend experience of the sample, which is non uncommon for non-utility companies.

TABLE L

DISCOUNTED CASH FLOW ANALYSIS: U.S. Utilities

Mid-Sized Electric Utilities (U.S. sample 1)		
Estimated Cost of Equity (%)	**Dividend Yield (%)**	**Expected Growth In Cash Flows (%)**
10.32	4.66	5.66
Gas Distribution Utilities (U.S. sample 2)		
Estimated Cost of Equity (%)	**Dividend Yield (%)**	**Expected Growth In Cash Flows (%)**
10.86	3.38	7.49

TABLE M

CAPM ANALYSIS: Canadian, U.S. Utilities and Non-Utility Companies

Peer Group Samples	Estimated Cost of Equity (%)	Estimated Future Risk Free Rate (%)	CAPM Beta	Estimated Overall Market Risk Premia (%)
Canadian Utility Sample 1	10.39	4.64	0.87	6.63
Canadian Utility Sample 2	10.60	4.64	0.90	6.63
U.S. Mid-Sized Electric Utilities (U.S. sample 1)	11.28	4.73	0.81	8.07
U.S. Natural Gas Distribution Utilities (U.S. sample 2)	11.32	4.73	0.82	8.07
U.S. Comparable Risk Non-Utility Companies (U.S. sample 3)	10.35	4.73	0.70	8.07

TABLE N

COMPARABLE EARNINGS[39] (Historical Market Returns_)

Peer Group Samples	Realized Returns (%)
Canadian TSX Listed Utilities (sample 1)	13.36
Canadian TSX Listed Utilities (sample 2)	16.07
Mid-Sized Electric Utilities (U.S. sample 1)	10.41
Gas Distribution Utilities (U.S. sample 2)	9.34
Comparable Risk Non-Utility Companies (U.S. sample 3)	10.75

TABLE O

RISK PREMIUM ANALYSIS: U.S. Utilities and Non-Utility Companies

Peer Group Samples	Estimated Cost of Equity (%)
Mid-Sized Electric Utilities (U.S. sample 1)	12.07
Gas Distribution Utilities (U.S. sample 2)	12.12
Comparable Risk Non-Utility Companies (U.S. sample 3)	12.71

126. The estimates of cost of equity capital using single-stage DCF analysis for each of U.S. samples 1 and 2 are quite similar: 10.32% for the sample of U.S. mid-sized electric utilities and 10.86% for the sample of U.S. moderate-sized gas distribution utilities.[40] The dividend yields of the DCF analysis utilize the stated dividend rates observed during early- to mid-2007, and stock prices sampled during April-May of 2007. The DCF cost of equity results for the electric utilities reflect the slowdown in earnings and cash flow growth during 2005 and continuing in 2006, which is largely a result of rising input costs, particularly for new investment, that is not being recovered in current

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[39] *Comparable Earnings* in the context of market-based assessment of realized returns is referred to elsewhere as *Historical Market Returns*.

[40] The three-stage DCF model results are similar in magnitude and are thus not reported.

rates. Expected growth relies on the historical experience for both internal cash flow and earnings per share.

127. The *CAPM* cost of capital results utilize estimated betas for two samples of Canadian utilities, which are based on the period 2002 forward and estimated monthly.[41] In the case of the samples of U.S. companies, including utilities and non-utilities, the CAPM analyses are based on and utilize Valueline estimates of CAPM betas, which are estimated on a weekly frequency over a 60-month period. Both the Canadian and U.S. CAPM analyses incorporate the Blume adjustment for long-run central tendency of betas to evolve toward unity.[42] All U.S. samples draw upon more contemporary betas, as estimated over the 60-month period ending in 2006, as it appears that the underlying market risks of electric and gas utilities have risen somewhat in the contemporary period. In addition, betas are also shown as for a five-year average of rolling averages for successive five-year periods ending 2002 (1998-2002); 2003 (1999-2003); and so forth. The CAPM analysis of the non-utility U.S. companies also utilize betas for the period ending 2006, in view of the significant difference in the typical 2006-ending beta value with reference to the rolling average.

128. The forward-looking risk-free or riskless cost rates used within the CAPM framework are not consistently drawn. In the case of the Canadian CAPM analysis of the cost of equity, the risk-free rate is set at the observed yields for the benchmark 10-year issues on Canadian government bonds for the period 2002-2006 of 4.64%. This recent, historically observed value[43] closely

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[41] The analysis that obtains CAPM betas for the Canadian utilities utilizes monthly yields on intermediate-term Canadian government debt as the surrogate for the risk-free rate. These yields are used for the determination of the historical risk premia for estimation of CAPM betas. However, these yields are only an approximation to the market returns on risk-free asset which, to be precise, include both the flow of interest income as well as *ex post* market appreciation (or loss should bond prices decline over the course of the month).

[42] The so-called Blume methodology derives from the work of Marshall Blume, as first presented in the article, "On the Assessment of Risk," *Journal of Finance*, Vol. 26, 1971. The alternative approach to adjust the estimated raw betas is the so-called Vasicek technique, as proposed by O.A. Vasicek in "A Note on Using Cross-Sectional Information in Bayesian Estimation of Security betas," *Journal of Finance*, vol. 28, 1973. Generally speaking, the Vasicek approach is considered the preferred methodology though considerable information is required for implementation. Commercial financial services including Bloomberg, Compustat and Valueline, utilize the Blume approach, whereas Ibbotson Associates employs the Vasicek correction method.

[43] It is useful to note that the yields on Canadian long-term debt declined dramatically in 2002 from the previous two years (5.84% for 2000 and 10.88% for 2001).

conforms to the recorded yields for the benchmark 10-year Canadian government bonds for mid-2007, 4.60%, which is the timeframe in which the cost of equity capital is estimated.

129. For the U.S.-based analysis, the study also utilizes 10-year yields on U.S. government bonds recorded for recent years (2000-2006). For intermediate term bonds, the monthly average yields over these contemporary years, 4.73%, appear to match fairly well with investor expectations during mid-year 2007, with observed 10-year yields of 5.00% and 5.10% for June and July, respectively. Accordingly, this value (4.73%) serves well as a historically-based risk-free cost rate for the CAPM analysis for the three U.S. samples. Nonetheless, this bond yield level resides at about 85 basis points above current 10-year government bond yields, in view of the recent sharp decline in interest rates since December 2007. For reference, the 2006 inflation-indexed U.S. long-term government bond yield resides at 2.53%, suggesting an expected 2.5% rate of overall price inflation (5.00% or 5.10% minus 2.53%) for the U.S., which is best captured historically by the chain-weighted gross domestic product (GDP) price deflator.

130. When applied to the Canadian and U.S. samples, the CAPM analysis obtains similar results, with the cost of equity estimates ranging from 10.35% for the Comparable Risk Non-Utilities (U.S. sample 3) to 11.32% for the U.S gas distribution utilities (U.S. sample 2). The corresponding CAPM results for the Canadian samples 1 and 2 are 10.39% and 10.60%, respectively.

131. The *Comparable Earnings* (Historical Market Returns) approach of our overall framework for estimation of cost of equity capital is in keeping with a market-based analysis. As a matter of interpretation, the Comparable Earnings approach, otherwise known as Historical Market Returns, provides the only relevant basis for determining the realized returns to capital. To a substantial extent, history is the basis upon which investors form expectations. In fact, the historical market returns interpretation of the Comparable Earnings basis is well founded by empirical evidence of capital market experience. For this reason, we draw upon the historical market returns realized by the four samples of Canadian and U.S. utilities as well as the U.S. comparable risk non-utility companies (U.S. sample 3). The realized market returns generally conform to the forward-looking estimates of cost of capital, including DCF,

CAPM, and Risk Premium, where the reported realized returns range from 9.34% for Moderate-Sized U.S. Gas Distribution Utilities (U.S. sample 2) to 13.36% for Canadian sample 1. The realized historical returns for Canadian sample 2 appear to be unusually high (16.07%) and may overstate the cost of equity capital if accepted in isolation of the valuation results for the other methods and samples. Accordingly, the cost of capital study results reported here do not incorporate Canadian sample 2 realized historical returns.

132. Finally, the interpretation of Comparable Earnings as either book returns to capital or authorized returns, as is so often the case, constitutes a clear example of circular reasoning, where regulators set authorized returns on a basis of book returns set by others. This results in book returns potentially departing from the underlying cost of capital by substantial margins. Thus, I suggest that the FTC, in its deliberation of return on equity employ reasonable caution in referring to realized book returns on equity as surrogates for estimates of the cost of equity, for the determination of the rate-of-return level for the Company.

133. The *Risk Premium* approach to valuation draws upon observed historical risk premia across realized market returns for classes of debt and equity vehicles. Risk premia can be calculated in many ways. The analyses, here, draw upon the risk premia reported and published by Ibbotson Associates. The analyses suggest that efficient capital markets demand substantially higher market rates of return on equity vis-à-vis debt of various terms. Specifically, equity risk premia are reported with respect to short-, intermediate-, and long-term government debt.

Cost of Equity Capital and Firm Size

134. It is worth noting that extensive analysis of realized returns within U.S. equity markets reveals that progressively higher equity risk premia—and, thus, cost of capital—attend small-sized companies, particularly for micro-sized companies like the Company. For this reason, the estimated cost of capital results and rate of return recommendations are conservative and, in fact, may understate the underlying cost of capital for the Company.

135. Risk premia associated with small size, sometimes referred to as small capitalization risk premia, reflect intuition, well established principles that serve as the foundation of finance theory, and the observed realities of capital markets. First, ordinary common sense would lead one to recognize that small entities face higher business risks than large entities. Higher risks attending small size come about from the principle of large numbers. Specifically, the financial impacts of random business events, which occur over the course of business enterprise, cannot be diversified by small entities as well as by large entities. Essentially, the impacts of business events within larger enterprises get absorbed within a pool of other events, both positive and negative, with the result that such events are substantially muted in their total impacts on the financial results of the enterprise.

136. The intuitive idea of diversification of business activity is reflected in portfolio theory. In this regard, the larger entity can be viewed as, essentially, a larger portfolio of individual business activities with the attending diversification effects, providing that individual business activities have less than perfect correlation.

137. Capital markets reveal that, among other factors, the variability of the returns to capital, reflected as operating income, will typically be higher for smaller entities than larger entities. Second, historical market returns for entities with smaller market capitalization will have higher variation than for entities with higher capitalization levels. Within the context of CAPM theory, the core of modern finance theory, the relevant and well known measure of risk is the covariation of market returns of individual equities with the market as a whole, normalized by the variance of the overall market, referred to as CAPM beta. Insofar as this notion of risk—*i.e.*, systematic risk—is the only relevant measure of risk given optimal portfolio theory, competitive capital markets would ensure that equities are priced at levels such that the realized market returns of individual equities would be ordered according to CAPM betas.

138. Essentially, CAPM theory would then suggest that, to the degree that the higher risks of small capitalization entities can be diversified—*i.e.*, are non-systematic—CAPM betas would still reflect the most relevant risks. To the degree that higher risks of small capitalization entities cannot be fully diversified—*i.e.*, are systematic—higher risks are reflected in higher CAPM

betas. As mentioned elsewhere, empirical studies suggest that CAPM estimates of the cost of capital systematically understate historical market returns for small capitalization entities.

139. Empirical evidence suggests that while CAPM betas are typically higher for smaller-sized equities, CAPM betas do not fully explain the realized market returns of small capitalization entities. Indeed, a substantial body of evidence suggests that CAPM underestimates historical market returns of—and thus understates the cost of capital for—small capitalization firms. In one interpretation, the difference between the realized market returns of small capitalization firms and the estimated market returns under CAPM constitutes the small-capitalization risk premium. A second interpretation is that, after accounting for various factors, it appears that size, as reflected in capitalization, is inversely related to historical market returns and that the relationship is systematic—both repeatable and non-random. The magnitude of small capitalization risk premium is large, as best demonstrated by the published analytical work of Ibbotson Associates, Eugene Fama and Kenneth French, Banz, Kaplan, and Roger Ibbotson. In the latest published work, the analyses of Ibbotson Associates[44] demonstrate that for entities organized into deciles according to capitalization, as a measure of size, size-related risk premia not captured by CAPM beta assume the magnitudes presented in Table P below:

[44] *SBBI Valuation Edition Yearbook* by Ibbotson Associates, 2007.

TABLE P

RISK PREMIA NOT ACCOUNTED FOR (UNDERESTIMATION OF HISTORICAL MARKET RETURNS) IN CAPM ANALYSIS[45]

Size Decile	Size-Related Risk Premium (%)
1	-0.36
2	0.65
3	0.81
4	1.03
5	1.45
6	1.67
7	1.62
8	2.28
9	2.70
10	6.27

140. It is useful to mention that, as reported[46], Decile 9 includes entities with market capitalization of $265.1-$586.4 million, while Decile 10 includes entities with market capitalization of $1.1-$265.0 million. Recent studies by Ibbotson Associates have further segmented Decile 10 into larger and smaller entities, with results that confirm the pattern shown above, with the smaller group of entities within Decile 10 demonstrating very high size-related premia not captured within CAPM beta. Excess market return (and cost of equity capital) not captured by CAPM—*i.e.*, size-related risk premium—appears to rise with progressively smaller sized entities. In addition, size premia are specific to industry and, generally speaking, we can infer that the size premium for electric utilities is somewhat smaller than for other industries. For the U.S. samples 1 and 2, industry-specific size-related risk premia are utilized in the study, though the industries are rather broadly defined.

141. CAPM theory, when used in isolation from other valuation methods, can be challenged for a number of reasons that warrant consideration for purposes of setting the rate of return for the Company. In terms of size-related risk

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[45] The deciles organize equities into capitalization groups, where the largest entities are within Decile 1, and the smallest entities are within Decile 10.

[46] As reported by Ibbotson Associates.

premia, the reasons for the understatement of market returns by CAPM for small-sized entities are perhaps not widely understood at this time. My general view, however, is that, for small entities, the cost of acquiring information regarding the prospects for future returns and assessment of risks is unusually high. Because the acquisition of information is costly, less information and knowledge within the investment community about small entities is available. Hence, investors with positions in small entities inherently incur higher risks. For small-sized entities, higher returns are thus the compensation for the assumption of higher risks. It is useful to emphasize that CAPM over long timeframes does reveal higher risk premia and cost rates for smaller entities. However, and as discussed here evidence also suggests that CAPM systematically understates risk premia, and thus the cost of capital, attending comparatively small sized equity listings. The study's Risk Premium analysis, which is based on the CAPM framework and explicitly incorporates sized-related risk premia not captured by CAPM beta, is incorporated into the analysis for the three U.S. samples, and finds that the cost of equity capital ranges from 12.07% to 12.71%. The size premium not captured by CAPM included within this range is estimated at a level of 1.20-1.60% for both the U.S. electric utilities (U.S. sample 1) and U.S. gas utilities (U.S. sample 2), and 1.90%-3.90% for comparable risk non-utility companies (U.S. sample 3).[47] Size-related premia have been extensively studied, for U.S. equity markets, and have also been shown to be present within equity market experience, internationally.

Cost of Equity Capital and Sovereignty Risk

142. The estimates for the cost of equity above do not incorporate any allowance for sovereignty risks. As we have discussed, sovereignty risk refers to risk differences of financial assets sourced across various sovereign countries. Such risks are relevant to the outstanding debt of public and private entities and common stocks that are traded either on exchanges of emerging economies. Sovereignty risks are also relevant to over-the-counter traded

[47] For the industry segment grouping that includes electric utilities, Ibbotson Associates reports a size premium of 3.20% for small entities relative to large. However, this level incorporates a premium that is captured by CAPM beta although the effects are very small. Second, this size premium level is for a fairly heterogeneous industry group.

securities. To better understand and estimate country risks, the study employs two general methods, referred to as *Credit Score Differences* and *Relative Risks of Equity Market Returns*. The first approach, *Credit Score Differences*, utilizes the surveys of securities traders involved in the assessment of financial markets of global capital markets. The second approach, *Relative Risks of Equity Market Returns* is based on the relative risks (statistical variance or standard deviation) of historical market returns for exchanges of emerging nations, with respect to exchange indexes of developed markets such as the U.S. NYSE Composite or S&P500 equity market indexes.

143. The *Credit Score Differences* utilizes the 2007 survey of credit scores conducted by *Institutional Investor*,[48] where the survey-based study results in credit scores of countries, with 174 countries included in the survey.[49] The approach estimates the statistical relationship between observed real interest rates among countries and the survey-based credit scores. Once estimated, the statistical relationship is then used as the basis to estimate the likely difference in short-term real interest rates (risk premium) that results from credit score differences, where the U.S. or a group of developed countries with high credit ratings serve as the benchmark.

144. The credit rating scores range up to a potential score of 100. Worldwide, Switzerland earns the highest survey-based credit score of 96.40, with the lowest score of 4.70 assigned to Somalia. The survey-based credit scores for Barbados is 63.40.

145. The study covers all sovereignties for which positive real short-term interest rates are reported. Of this sample of 73 countries, the statistical analysis is conducted on credit score and interest rate data for 55 counties with credit scores no less than 40.00, with Nigeria having the lowest included credit score. The analysis is conducted using two sets of data, including 1) individual country credit scores and real short-term interest rates, and 2) 10-

[48] Institutional Investor conducts its survey semi-annually.

[49] A similar approach would be to utilize the credit ratings assigned by risk assessment and credit rating service entities, such as Moody's, S&P, and Fitch. The credit ratings would need to have assigned numeric values that are then used as the basis to gauge real interest rate differences.

observation averages of credit scores and interest rates. The analysis results suggest that short-term real interest rates rise by 4.1 to 4.8 basis points for each 1.0 point decline in credit score. With the U.S. serving as the benchmark low credit risk country (credit score 94.10), the estimated sovereignty risk premium for Barbados is from 1.25% to 1.48%. Using the average credit scores for selected Caribbean neighbors of Barbados including Bahamas, Trinidad & Tobago, and Jamaica, the analysis obtains an implied level of sovereignty risk premium for the group ranging from 1.45% to 1.72%.

146. The *Relative Risks of Market Returns* analysis is based on annual market indexes for three Caribbean stock exchanges including those for Barbados, Trinidad & Tobago, and Jamaica. Of the Caribbean exchanges, the Barbados Stock Exchange has the longest history, with its composite index reaching back to 1989. The index for the Trinidad and Tobago stock exchange is available from 1997, while the index for the Jamaican Stock Exchange is available from 2001. The S&P 500 index is used as the benchmark exchange index in view of its market capitalization and because of its wide recognition as an overall indicator of market performance. The analysis calculates annual market returns for the stock market indexes (without recognition of dividends), and the statistical variance of market returns, as shown below in Table Q.

TABLE Q

ANNUAL MARKET RETURNS FOR CARIBBEAN STOCK EXCHANGES[50]

Year	Barbados Stock Exchange	Jamaican Stock Exchange	Trinidad & Tobago Stock Exchange	S&P 500 Index
1990	-13.24%			-6.56%
1991	1.58%			26.31%
1992	-15.37%			4.46%
1993	19.92%			7.06%
1994	6.28%			-1.54%
1995	-5.38%			34.11%
1996	-0.03%			20.26%
1997	50.52%			31.01%
1998	47.58%		23.86%	26.67%
1999	-8.37%		-4.32%	19.53%
2000	-14.23%		5.76%	-10.14%
2001	-6.25%		-1.66%	-13.04%
2002	10.55%	34.21%	25.65%	-23.37%
2003	29.04%	48.88%	27.23%	26.38%
2004	26.36%	66.68%	54.82%	8.99%
2005	5.83%	-7.23%	-0.68%	3.00%
2006	-6.77%	-3.67%	-9.20%	13.62%
Cumulative Realized Historical Returns	5.82%	24.38%	11.90%	8.52%
STATISTICAL VARIATION IN MARKET RETURNS				
1990 - 2006	20.57%			16.94%
1998 - 2006			20.84%	18.0%
2002 - 2006		32.46%		18.4%

147. As expected, the Caribbean exchanges reveal substantially higher risks (variation of realized returns) than U.S. equity markets, as represented by the S&P 500 index.

148. Estimates of sovereignty risks constitute real capital cost differences, and are implicitly present in the differences in *ex ante* equity market returns between

[50] While the Jamaican Stock Exchange is shown above, the study does not utilize experience from the Jamaican exchange because of its history is of insufficient length from which to estimate relative risks.

the Caribbean region and U.S. markets, as reflected in, for example, the S&P 500 index. On average, risk premia with respect to intermediate term debt for the S&P 500 index have ranged from 5.5% to over 8.0% for the period 1970 forward. Using values of 6.0% and 8.0%, the incremental risk premium associated with the Barbados Stock Exchange is equal to (20.57%/16.94% -1)*(6.0 to 8.0)%, or 1.12% to 1.72%. Incorporating the experience of the Trinidad & Tobago Stock Exchange into the analysis yields a similar level of 1.29%-1.49%.

149. In summary, the Credit Score Differences and Relative Risks of Equity Market Returns obtain a sovereignty risk premium for Barbados ranging from 1.12% to 1.72%, with an average value of 1.43%.[51]

150. The cost of equity studies described above draw upon the cost of capital tool box and provide reliable and well-defined estimates for return on equity. The cost of equity estimates result from the application of the valuation methods to two Canadian utility samples and three U.S. samples including two groups of utilities and a group of comparable risk non-utility companies. The results range from 8.65% to 11.51%, notwithstanding the exceptionally high Historical Market Returns (Comparable Earnings) realized for the Canadian utilities, sample 2.

151. These comparable risk peer group estimates of the cost of equity likely understate the Company's cost of equity for several reasons. It is essential that several factors not incorporated directly into the cost of equity capital studies, as reviewed above, be presented and fully accounted for, as follows:

(i) Issuance Costs: The analyses do not incorporate issuance costs which, for very small entities, are likely to be upwards of 7.00-9.00% of the realized proceeds from the sale of equity securities in order to cover registration fees, audit fees, and the charges for underwriting and marketing the securities. Recognition of issuance costs typically translates into approximately 30-40 basis points. Only a portion of the incremental equity capital of the Company is likely to be obtained from

[51] Also, this estimated range of the level of sovereignty risk is paralleled by the difference between the real risk-free interest rates of Central Bank debt of Barbados and the U.S., as presented earlier within the Report.

external sources[52]—*i.e.*, through the sale of new shares—which implies that, to determine the opportunity cost of equity, the effective adjustment for issuance costs is less. This is because issuance costs are applicable only to the share of incremental capital raised externally. Three basis points (0.03%) are incorporated into the return on equity recommendation.

(ii) Isolation Associated With An Island System: As the report discusses, the Company serves an island economy and is thus not part of the larger integrated systems of the major continent. Accordingly, the Company is exposed to an unusual business context resulting in inherently higher operating risks than the risks of continental firms making up the peer group of comparable risk entities for which the cost of equity estimates are determined. However, no explicit cost rate adjustment is incorporated into the return on equity recommendation for isolation.

(iii) Size-Related (Small Capitalization) Risk Premium: Size premia for very small entities are explicitly captured only within the Risk Premium cost of equity capital methodology, as applied to the U.S. sample companies. While, in the absence of further research, we cannot be sure, it is likely that the cost of equity for the Company is somewhat understated for this reason. As reported, the size-related risk premium appears to be in the range of 1.20-1.60% for comparable risk utilities, and noticeably higher for non-utility companies. In conservative fashion, a range of size premia of 1.20% (low) and 1.60% (high) is applied to the market-based estimates of the cost of equity.[53]

(iv) Sovereignty Risks: Because the technical estimates of the cost of equity capital are obtained from samples drawn from North America, such estimates do not incorporate sovereignty risks specific to Barbados or its neighbors in the Caribbean region. Based on two methods used in the study—including Credit Score Analysis and

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[52] The remainder of new equity capital of the firm is raised internally, and shows up in the ongoing accrual of retained earnings.

[53] The adjustment is factored appropriately in order to not "double count" the size-related risk premium, which is explicitly incorporated with the Risk Premium analysis.

Relative Risks of Market Returns—country risks are likely to range from 1.12% to 1.72%, with an average of 1.43%.

(v) High Equity Participation: The weighted average cost of capital incorporates fairly high equity participation of 65%, when compared to the sample of comparable risk U.S. electric and gas distribution utilities. The Company's comparatively high equity share is necessary in view of business context, an isolated island system facing substantial capital expenditures. Nonetheless, because increased equity share in total capital reduces capital risks, other factors constant, the Company's high equity participation translates into a downward adjustment to the cost of equity. Accordingly, a downward adjustment of 51 basis points is incorporated in the study results.[54]

(vi) Quarterly Payment of Dividends: Where relevant, the quarterly payment of dividends typically yields an upward adjustment of 20-30 basis points. The cost rate adjustment for quarterly payments is 25 basis points.

152. The cost of equity study suggests that the return on equity averages 11.16%, with a range from 9.34 to 13.36%, as far as the market-based cost estimates are concerned. [55] (As mentioned above, the study declines to include the extreme value of 16.07% realized historical returns for Canadian sample 2.)

153. Taking full account of the above adjustment factors suggests, moreover, that the cost of equity capital for the Company resides at a level well above the market cost estimates that are obtained from the application of the battery of cost of capital methods to the five North American samples. These adjustment factors, moreover, are additive. Taking a conservative view of the adjustment factors through recognition of lower estimated values for size premia and sovereignty risks results in a minimum adjustment of 2.05%.

[54] The adjustment amount, in basis points, is related to the sensitivity of the cost of common equity, as a matter of assumption, to the impact of an increase in equity share on the volatility in earnings and cash flow per share equity returns. However, the adjustment does not account for the samples of companies used in the study, including Canadian samples 1 and 2 and the U.S. non-utility company sample (sample 3), which have equity participation of 70%, thus more closely approximating that of the Company.

[55] This value is obtained by calculating the average of the cost of equity estimates that result from the four methodologies. In addition, the average of all the individual market cost of equity estimates (excluding the 16.07% for Canadian sample 2) is virtually identical (11.13%).

Alternatively, utilizing the upper level risk premium estimates for size and sovereignty risks lead to an adjustment level of 2.71%. This range of adjustment can be viewed as upper and lower bounds—2.05% and 2.71%, respectively. Applying these adjustment factors to the estimate of 11.16% for the market cost of equity for North American utilities obtains an adjusted cost of equity for the Company of 13.18% to 13.85%, with 13.51% the average. Accordingly, in my opinion, the Company should adopt, in its electricity rate review application before the FTC, 13.50% for Return on Equity.

XVI WACC and RATE OF RETURN: THE BARBADOS LIGHT & POWER COMPANY LIMITED

154. As mentioned, the weighted average cost of capital (WACC) incorporating the weighted cost rates for both traditional components and non-traditional elements[56] is the basis for determination of the overall rate of return. For the development of the WACC and the overall rate of return, an appropriate starting point is the observed capital structure stated on a traditional basis. For the test period 2008, the Company underwrites its assets with the following capital structure, shown with capitalization shares and corresponding cost rates as shown below in Table R:

TABLE R
WEIGHTED AVERAGE COST OF CAPITAL FOR CONVENTIONAL CAPITAL STRUCTURE
Average of Year-End Balances for 2006 and 2007

Capital Component	Observed Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$115,406	21.44%	5.25%	1.13%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$422,804	78.56%	13.50%	10.61%
Total	$538,210	100.00%		11.73%

[56] Traditional financing vehicles include long- and short-term debt, preferred and preference stock, and common equity. Non-traditional elements include customer deposits, deferred balances of income taxes, investment tax credits and, for Barbados, the manufacturers' allowance.

155. As can be seen, the Company is financing assets with an unusually high concentration of equity participation, resulting in a WACC (overall rate of return requirement), not including income tax effects, of over ten percent. Viewed in the context of the capital structure experience of the industry, the Company's high equity participation may cause the Company's WACC to depart from a least-cost level, although the Company's unusual business context provides reason for equity to remain at a fairly intensive level and above that of the electric power industry as a whole. Accordingly, in my opinion the FTC should utilize a capital structure that departs from the Company's observed capital structure. Specifically, there should be consideration of a policy-based imputed capital structure that contains 65% equity participation. The WACC associated with this policy-based capital structure is shown below in Table S:

TABLE S

WEIGHTED AVERAGE COST OF CAPITAL FOR POLICY-BASED CONVENTIONAL CAPITAL STRUCTURE

Average of Year-End Balances for 2006 and 2007

Capital Component	Implied Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$188,374	35.00%	5.25%	1.84%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$349,837	65.00%	13.50%	8.78%
Total	$538,210	100.00%		10.61%

156. As can be seen, reducing equity participation from 79% to 65% lowers the weighted average cost of capital by over 110 basis points. The imputed capital structure shown above significantly reduces equity participation, while also sustaining sufficient equity and debt-equity balance. This result, I believe, is consistent with the least cost financing mix for the Company's capital resources given its inherent business context and risks, while also providing the Company with a satisfactory level of interest coverage.

157. The proposed approach is in keeping with the capital attraction and financial integrity concepts of fair rate of return principles. The 65% participation of equity is plentiful—a level that is above that of most mid-sized and large

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electric utilities in the U.S., though a number of registered Canadian utilities tend to utilize equity participation levels that are equivalent to or above those of their U.S. counterparts. This level of equity participation is adequate and desirable, when viewed from the Company's unusual business context and small size.

158. The policy-based traditional capital structure with 65% equity participation provides the basis for the regulatory capital structure that, as mentioned, incorporates both *traditional* and *non-traditional capital* components, as shown below in Table T:

TABLE T

RATE OF RETURN RECOMMENDATION FOR 2008: WEIGHTED AVERAGE COST OF CAPITAL FOR REGULATORY CAPITAL STRUCTURE

Based on Total 2007 Balances

Capital Component	Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$188,374	31.32%	5.25%	1.65%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$349,837	58.17%	13.50%	7.85%
Customer Deposits	$20,010	3.33%	6.46%	0.22%
Deferred Investment Tax Credits	$30,099	5.00%	10.61%	0.53%
Deferred Manufacturers' Allowance	$13,052	2.17%	10.61%	0.23%
Total	$601,371	100.00%		10.48%

159. The inclusion of non-traditional elements such as the manufacturers' allowance, when "costed" at the policy-based WACC level, results in an overall cost of capital that is slightly lower, 10.48%, whereas the policy-based WACC is 10.61%. In my opinion, the FTC should adopt a WACC (and overall rate of return recommendation) of 10.48% for setting electricity rates for the Company in the current proceeding.

SWORN TO by the deponent)
Robert J. Camfield)
this 7th day of May)
2009, before me:)

Jerri L. Watson

NOTARY PUBLIC

I, Jerri L. Watson, Notary Public in and for the State of Wisconsin in the United States of America, do hereby DECLARE that on the 7th day of May 2009, personally appeared before me a male person who identified himself to be the within named ROBERT J. CAMFIELD and did in my presence sign and execute the Affidavit as and for his free and voluntary act and deed.

IN TESTIMONY WHEREOF I have hereunto subscribed my name and affixed my seal of office this 7th day of May, 2009.

Jerri L. Watson
Notary Public
My commission expires:
9/5/10

0580

RC1

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates

EXHIBIT "RC 1"

This is a copy of my resume marked Exhibit **"RC 1"** mentioned and referred to in paragraph 6 of my Affidavit.

SWORN TO by the deponent)
Robert J. Camfield)
this 7th day of May)
2009, before me:)

Robert J Camfield

Jessie L. Watson
NOTARY PUBLIC

I, Jessie L. Watson, Notary Public in and for the State of Wisconsin in the United States of America, do hereby DECLARE that on the 7th day of May 2009, personally appeared before me a male person who identified himself to be the within named ROBERT J. CAMFIELD and did in my presence sign and execute the Affidavit as and for his free and voluntary act and deed.

IN TESTIMONY WHEREOF I have hereunto subscribed my name and affixed my seal of office this 7th day of May, 2009.

Jessie L. Watson
Notary Public
My commission expires:
9/5/10

EXHIBIT RC 1

Robert J. Camfield

RESUME

April 2009

Address:

4610 University Avenue, Suite 700

Madison, WI 53705-2164

Telephone: 608.231.2266

Fax: 608.231.1365

E-mail: rjcamfield@caenergy.com

Academic Background:

M.A., Western Michigan University, 1975, Economics (High Pass, Comprehensive Exams)

B.S., Ferris State University, 1969, Management

Interlochen Arts Academy, 1964

Positions Held:

Vice President, Christensen Associates Energy Consulting, LLC, present

Senior Economist, Laurits R. Christensen Associates, Inc., 1994-2002

System Economist, Southern Company Services, 1993-1994

Economist, Southern Company Strategic Planning, 1992-1993

Strategic Planner, Southern Company Strategic Planning, 1990-1992

Project Manager, Georgia Power Company, 1983-1990

Chief Economist, Public Utilities Commission, State of New Hampshire, 1979-1983

Staff Economist, Michigan Public Service Commission, 1976-1979

Professional Experience:

I served as the chief economist of a regulatory agency and system economist for a major electric service provider. My experience involves wholesale and retail energy market issues with a focus on transmission, regulatory strategy, cost allocation, rate of return and capital valuation, marginal cost analysis, energy contracts, performance benchmarking, and electricity market forecasting. For clients, I have been involved in the assessment of electric generation technologies, negotiation of power contracts, finalization of franchise licenses, and internal transfer pricing. I have managed power procurement processes, and negotiated power purchase agreements and transmission contracts. I have participated in several large projects abroad, including the management of a market restructuring project in Central Europe. I have served on national committees and advised major electric companies on corporate strategy. Innovations include two-part tariffs for transmission services, marginal cost-based cost-of-service, web-based *self-designing retail electric tariffs, and efficient pricing of distribution services.* I have represented and testified on behalf of utilities, consumer advocacy groups, associations, transmission companies, regulatory agencies, generation companies, and power delivery companies in regulatory proceedings and public forums on a number of topics including cost of capital, power supply contracts, cost of service allocation, phase-in plans, load forecasts, corporate performance, transmission congestion, rate design, and expansion plans. I served as program director for the Edison Electric Institute's Transmission and Wholesale Markets School from 1999 through 2008.

Selected Projects:

Report on demand side participation in contingency reserves, for a major electric utility.

Development of a load and energy forecast and accompanying regulatory report, for a major electric utility.

Report reviewing alternative transmission business models, for a major electric utility.

Negotiation of terms for power supply contract, for a distribution utility.

Analysis of power procurement processes and outcomes for electricity service providers, and justification for incentive allowances, for a regulation agency.

Independent mediator of disputed issues regarding load forecast methodology, on behalf of agency staff and a utility applicant, in an integrated resource planning docket before a regulatory agency.

Cost of service allocation study on behalf of an intervening party within a major utility rate case.

Oversight of the consulting team preparing a natural gas rate case filing, on behalf of a combination electric-natural gas utility. Project work includes cost of service allocation, preparation of the Minimum Filing Requirements, design of retail tariffs, and cost of capital/rate of return recommendation and testimony.

Position paper on stranded costs resulting from off-system purchases by distributors, for a major generation and transmission cooperative (G&T).

Projections of escalators for determining commercial terms, for use in negotiation of new coal contracts.

Preparation of load and energy forecast for a utility.

Analysis and recommendations of regulatory issues underlying total costs (revenue requirements) for a utility's rate case filing. The issues, including fair value/original cost rate base, construction work in progress, normalization/flow through of income tax effects from accelerated depreciation/investment tax credits, working capital, and depreciation policy, were addressed in a series of discussion papers.

Cost of capita/rate of return recommendation and testimony for a utility rate case filing.

Report on integration of demand response into transmission and distribution planning.

Assessment of and recommendations for retail market strategies focused on conservation, efficient pricing, and renewable resources, for an electricity service provider.

Cost of capital/rate of return recommendation and testimony for a utility rate case filing.

Development of the draft commercial terms for a power supply contract for a renewable resource facility.

Negotiation of contracts for transmission services, for an electric distribution company.

Review of methodology and process for development of load and energy forecasts, for a major electric utility.

Development of cost allocation methodology for assignment of profits associated with off-system sales to jurisdictions, for a major electric utility.

Development of the structure of a proposed fuel adjustment clause for retail electric services, for a major electric utility.

Review of the commercial terms of a proposed power supply contract, for a major electricity service provider.

Review of a utility rate case filing, on behalf of a major electricity service provider.

Review and assessment of the efficiency of fuel procurement practices on behalf of a major electricity service provider.

Review of economic cost allocation methods and options, for an electric generation and transmission company.

Determination of strategy for transmission services, where options include exiting an RTO, the purchase of services from a private Transmission Services Coordinator, and the formation of a statewide or regional ISO with a consortium of electric utilities.

Analysis of the benefits and costs of electric transmission expansion plans, for an independent transmission company.

Review of the design of market-based buy-through options for retail electricity curtailment contracts.

Support for the negotiation of long-term power supply contracts, including development of commercial terms.

Assessment of transmission costs and risks, in support of power supply contracts.

Management of a power procurement process including the determination of strategy and approach, development and issuance of a request for proposal, evaluation of offers, and the negotiation of power contracts.

Development of a regulatory phase-in plan of the costs associated with new wholesale power supply contracts.

Factor models for the determination of cost of capital, for a consortium of electric utilities.

Assessment of the secondary economic impacts (multiplier effects) on regional economies arising from the construction and commercial operation of new generating stations.

Comparative assessment of the economic viability of contemporary power generating technologies, for a major electric utility.

Definition of proposed RTO reporting requirements, for an association of electricity service providers.

Comparative assessment of the economic costs of electric distribution services.

Transfer pricing for generation and transmission services, for a major electric utility.

Evaluation of a proposed amendment and extension to a power supply contract, for an electric utility.

Interpretation and assessment of the Standard Market Design proposal developed by the Federal Energy Regulatory Commission, for a major electric utility.

Development of software for the evaluation of transmission expansion plans, for a major transmission company.

Development of methods to assess benefits and costs of transmission expansion plans.

Estimation of marginal cost for cost-of-service allocation, for a major electric utility.

Forecasts of regional electric wholesale prices and assessment of the reliability of power delivery, in support of the negotiation of a wholesale power supply contract for an electric power merchant.

Valuation and assessment of hydroelectric power plants, for a major electric utility.

Economic assessment of transmission expansion plans, for a major transmission company.

Assistance in the specification of the franchise licensing agreement underlying a utility privatization, for an international energy company.

Determination of the benefits of expanded network metering, for a large incumbent transmission service provider.

Specification of the terms associated with a purchased power contract, for a major electric utility undergoing corporate unbundling.

Estimation of regional wholesale prices for reserve services, for a major electric utility.

Evaluation of generation investment strategy, for a major electric utility.

Preparation of long-term projections of regional wholesale power prices, for a major electric utility.

Development of the blueprint and structure for wholesale electricity market design, for a major transmission company.

Estimation of consumer electricity outage costs (value of reliability), for a major electric utility.

Estimation of generator costs and network locational prices, for an electric distribution company in New Zealand.

Determination of principles and definition of the main elements for electricity market restructuring and tariff design, for a Central European country.

Analysis of retail tariff design and strategy, for a major electricity service provider.

Development of transmission and distribution marginal costs, for a large municipal electric utility.

Determination of economic costs and tariff prices, for the Turkish Electricity Authority.

Evaluation of transmission network costs and tariffs, for the national grid company of a Central European country.

Development of optimal power flow software for determining transmission spot prices, for a major electricity service provider.

Estimation of marginal costs for jurisdictional and class cost-of-service allocation.

Development of electric transmission spot pricing capability and software.

Estimation of wholesale electricity market prices in the Northwest region.

Determination of locational marginal costs and the implications for real time pricing.

Development of marginal costs and cost-of-service allocation study.

Development of pricing strategy for an electric distribution utility operating in an open retail access region.

Development of a cost-of-service study and retail pricing, for an electric distribution utility.

Preparation of a cost-of-service study utilized marginal costs.

Analysis of the impact of real-time pricing program options.

Development and implementation of generation and transmission transfer pricing for a major electric utility.

Economic analysis of retail electricity pricing options.

Economic analysis of time-of-use electricity retail service design options.

Development, evaluation, and feasibility assessment of the business case for the formation of a financing subsidiary.

Economic assessment of alternative cycles and schedules for nuclear plant refueling.

Assessment of retail electricity marketing strategies.

Estimates of marginal costs of power delivery services provided by U.S. electric utilities.

Operations and Management Improvement Program, a World Bank funded project for the Turkish Electricity Authority.

Professional Papers and Key Reports:

"Review and Recommendations: Forecast Methodology and Process," a report regarding the approach to load and energy forecasting, for a major integrated electric utility, 2008.

"Cost of Capital Report" *for an integrated electric utility, 2008.*

"Regulatory Policy Regarding Construction Work In Progress," a discussion paper prepared for an integrated electricity service provider, 2007.

"Asset Valuation: Original Cost and Fair Value Approaches," for an integrated electric service provider, 2007.

"Marginal Costs of Electricity Services," for an electric utility, 2007.

"Conservation Strategies and Resource Options," for a major electric utility, 2007.

"Rate of Return for Electric Distributors," for the Electricity Distributors Association, Ontario, Canada, 2006.

"Comments Regarding Staff Proposal for Rate of Return and Incentive Regulatory Mechanism," for the Electricity Distributors Association, Ontario, Canada, 2006.

"Economic Impacts of New Power Plants on Regional Economies," for a generation and transmission company, 2006.

"Other Factors Report," for American Transmission Company, 2005.

"*Methodology and Study, Comparators and Cohorts Study for 2006* EDR," for the Ontario Energy Board, 2005.

"Power Procurement Options and Strategies," for an electric utility, 2005, co-authored with Mathew Morey.

"Approaches for Designing and Pricing Unbundled Transmission and Ancillary Services," for an integrated electric service provider, 2004, co-authored with Laurence Kirsch.

"Principles and Practices of Power Procurement," 2004, co-authored with Kelly Eakin, Mathew Morey, and Ross Hemphill.

"Findings and Recommendations: Comparators and Cohorts for Electric Distribution Rates," for the Ontario Energy Board, 2004.

"History, Assessment, and Status: U.S. Electricity Markets," a discussion paper delivered before the annual national symposium on electric market restructuring, Poland, 2004.

"Methodology and Software for Evaluation of Transmission Development Options Under Open Market Conditions," CIGRE, April 2004, co-authored with F. Buchta, D. Armstrong, and W. Lubicki.

"A Cost-Benefit Analysis of RTO Options," a report prepared for LGE Energy Corporation, September 2003, co-authored with Blagoy Borissov, Laurence Kirsch, and Mat Morey.

"Methodology for Economic Assessment of Transmission Plans Within Unbundled Power Markets," EPRI Report #54215, May 2002, co-authored Rajesh Rajaraman.

"Determining the Marginal Costs of Transmission," a discussion paper prepared for a major electricity service provider, July 2003.

"Market Value Assessment of Hydro Units," for a major electric utility, 2003, co-authored with an engineering firm.

"Implications of SMD and RTOs for Retail Pricing," for a major retail service provider, July 2002.

"Exploring Transmission PBR and Power Market Reform," National PBR Conference, 2001, co-authored with Ross Hemphill.

"Incorporating Reserve Services and Scarcity Rents Into Wholesale Price Forecasting," EPRI Pricing Forecasting Conference, 2001, co-authored with James Lamb, David Armstrong, and David Glyer.

"Self-Designing Tariffs," EPRI International Pricing Conference, 2000, co-authored with David Glyer and John Kalfayan.

"The New Pricing Organization," EPRI International Pricing Conference, 2000, co-authored with Michael O'Sheasy.

"Efficient Pricing of Transmission Services," *The Electricity Journal*, 2000, co-authored with Anthony Schuster.

"Pricing in Competitive Electricity Markets," *Distribution Services*, 2000, Ahmad Faruqui and Kelly Eakin, eds., Kluwer Academic Publishers, 2000, co-authored with Laurence Kirsch.

"Marginal and Average Power Losses," a technical discussion paper focused on the determination of line losses for power delivery systems, 1999, co-authored with David Glyer and Tom Gorski.

"Estimation of Marginal Costs for Real-Time Pricing," a technical report that reviews alternative approaches to determined short-run marginal costs, 1998.

"Marginal Costs of Distribution Wires Services," a technical discussion report that defines the theoretical basis and empirical methodology to determine the marginal costs of distribution services, 1999.

"Market Blueprint," for the transmission company of a Central European country. A report by an international team of experts for a transmission company facing market reform within a Central European country, 1999, co-authored with Charles Clark and Laurence Kirsch.

"Marginal Costs of Distribution Wires Services," a technical report of estimates of marginal distribution costs, 1998, co-authored with Boon-Siew Yeoh.

"Tariff Study," an EPRI report to the Polish Power Grid Company. The report provides recommendations for market reform and restructuring. Recommendations to unbundle electric service into competitive and regulated sectors are provided. The report also provides estimates of 1) competitive generation prices with locational dimensionality and, 2) estimates of the net benefits from restructuring, 1999, co-authored with Charles Clark and Laurence Kirsch.

"Developing and Pricing Distribution Services," delivered before EPRI's Innovative Electricity Pricing Conference, 1998, and also in *Pricing in Competitive Electricity Markets*, Ahmad Faruqui and Kelly Eakin, eds., Academic Press, 2000, co-authored with Laurence Kirsch.

"Determination of Location and Amount of Series Compensation to Increase Power Transfer Capability," presented before the International Association of Electrical and Electronic Engineers, 1996, co-authored with Fernando Alvarado, Rajesh Rajaraman, Arthur Maniaci, and Sasan Jalali.

"Open Transmission Access: An Efficient, Minimal Role for the ISO," International Conference On System Sciences, 1996, co-authored with Fernando Alvarado and Rajesh Rajaraman.

"Transmission Comprehensive Marginal Costing," a report covering the conceptual design for software to determine locational prices, EPRI, 1996, co-authored with Keith R. Calhoun, David Glyer, Laurence Kirsch, Romkaew Broehm, and Michael Salve.

"Load Response Modeling Within Network Systems," a white paper that provides empirical estimates of the net benefits to consumers and service providers realized from incorporating spatially differentiated load response into system operations, EPRI, 1996, co-authored with Steve Braithwait, Pankaj Sahay, Arthur Maniaci, and Rajesh Rajaraman.

"Incorporating Optimal Power Flow Capability," a white paper that contrasts Optimal Power Flow methods and provides recommendations on incorporating Optimal Power Flow (OPF) into EPRI software, 1996, co-authored with Fernando Alvarado and Alfred Shultz.

"Transmission Pricing Strategies," a report that reviews transmission pricing methodologies and provides guidelines to a major integrated electric system to develop transmission tariffs, 1995, co-authored with Romkaew Broehm and Laurence Kirsch.

"Methodology to Estimate Regional Wholesale Power Prices," a technical white paper that presents, in substantial detail, a methodology to develop projections of power prices for regions of the U.S., 1995.

"Task II: Tariff Setting Mechanism" a report to the Turkish Electricity Authority. Task II was the second of two major scope of service areas of the *Operations and Management Improvement Program* (OMIP), a World Bank funded project. Task II (Tariff Setting Mechanism) involved the determination of financial costs; estimation of long-run marginal costs including generation, transmission, and distribution services; allocation of financial costs; and retail tariff design, 1993-1994.

"Managing Risk in Restructured Power Markets," a technical white paper on risk management methodologies, 1997, co-authored with Kathleen King, Pankaj Sahay, Fritz Schulz.

"Profitability of Retail Market Segments," a report of the expected long-run profits obtained from serving various retail markets for a major retail service provider, 1989.

"Profit Impact of Employment Multipliers," a report of the secondary profit impacts realized from the location of new business customers in the region served by an electric utility, 1988.

"Secular Distortions in Regulated Prices and Impacts on the Cost of Capital to Utilities," a discussion paper presented at the Eastern Economics Association that demonstrates the degree that investors discount internal cash returns from deferred taxes or non-cash returns associated with the allowance for funds used during construction (AFUDC), 1981, co-authored with Professor Peter Williamson.

"Long-Run Marginal Costs," a technical report of projections of marginal costs of generation, transmission, and distribution services provided by a major electric utility, 1985-1988.

"Impact of Electric Prices on the Regional Economy," a report that provides estimates of the impacts of regional electric prices on the costs of doing business within regions, 1985.

"Three Mile Island Two" a brief provided to the Legislature of the State of Michigan, 1979.

"Assessment of the FEA Long-Term Supply-Demand Model," a report to the Michigan Public Service Commission, 1978.

National Conferences, Engagements, and Technical Workshops:

Chair, "Electricity: A Rising Cost Industry," Chicago, September 2008.

Speaker at the conference "Managing Physical and Financial Uncertainty in the Power Industry," New York Mercantile Exchange, New York, June 2007.

Speaker and panelist at the "Annual Executive Symposium" of the Electricity Distributors Association, Ottawa, Canada, October 2006.

Speaker at the conference entitled "Transmission Reliability: Determining Appropriate Standards and Metrics," Washington D.C., September 2006 (co-speaker with Laurence D. Kirsch).

Speaker at a seminar focused on "Cost and Performance Benchmarking for Electric Utilities," Toronto, Canada, October 2006.

Speaker and workshop lecturer at the conference entitled "Transmission and System Reliability," Cape Cod, September 2005.

Speaker at the conference entitled "Organization and Governance of the Market Agent," Washington D.C., April 2005.

Chair and workshop lecturer ("Market-based Criteria and Evaluation of Transmission Expansion Plans") at the national conference entitled "Assuring Reliability, System Operations, and Network Expansion," San Francisco, October 2004.

Lecturer at the week-long course on Public Utility Regulation sponsored by the Wisconsin Public Utilities Institute, University of Wisconsin, Madison, October 2003.

Discussant on a panel of experts on the topic of market organization, conducted for a delegation of officials of the Korean electricity industry, sponsored by EPRI, Palo Alto, September 2003.

Chair and workshop lecturer ("Market-based Evaluation of Transmission Plans") at the "Markets for Power" conference, Denver, September 2003.

Discussant at the workshop on market-based expansion of networks, conducted before a delegation of officials of the Korean electricity industry, sponsored by EPRI, Madison, July 2003.

Week-long seminar on market organization issues, conducted for a delegation from the Korean Power Exchange, sponsored by EPRI, Palo Alto, May 2003.

Conference chair and speaker at the national conference entitled "Linking Wholesale and Retail Markets, Denver," April 2003.

Program Director and lecturer for the Edison Electric Institute's *Transmission and Wholesale Markets School*, University of Wisconsin, Madison, 1999-2008.

Lecturer on marginal costs at a three-day workshop organized for a large municipal utility.

Discussant at a workshop on ancillary services for a large integrated electric service provider, Denver, 2002 (co-presenter with Laurence Kirsch).

Lecturer at a three-day workshop on wholesale market design for a large integrated electric service provider, 2002 (co-presenter with Laurence Kirsch).

Lecturer at a three-day workshop entitled "Locational Pricing and Market Design," sponsored by WestConnect RTO, Phoenix 2002.

Session chair and speaker on the topic of performance-based regulation for transmission, at the national conference entitled "Performance-Based Ratemaking," Denver 2001.

Presenter at the "Review of U.S. Electric Markets" seminar for a delegation of officials of the power industry of China, Atlanta 2001.

Speaker and workshop lecturer at the workshop on distributed resources at the conference entitled "Unbundling and Pricing Wires Services," Philadelphia, 1999 (co-presenter with Ross Hemphill).

Speaker on the topic of "Technical Methods for the Design of Unbundled Transmission and Distribution Tariffs" at the workshop entitled "Unbundling Electric Power," sponsored by the Polish Power Grid Company, Warsaw, 1999.

Speaker on the topic of "Bottlenecks within Midwest Power Markets" at the conference entitled "Power Markets in the MAIN and MAPP Regions," Chicago, 1999 (co-presenter with Rajesh Rajaraman).

Discussant on the topic of "Pricing Transmission Services" delivered before the economics committee of the Edison Electric Institute, San Diego, 1999.

Speaker on the topic of "The Key to Profits: Understanding Costs and Customer Behavior" at the conference entitled "Measuring Customer Profitability For Utilities" New Orleans, 1998 (co-presenter with Ahmad Faruqui).

Speaker on the topic of "Pricing Transmission Services" at the conference entitled "Successful Transmission Pricing," Houston, 1997.

Lecturer at the workshop on "Pricing Distribution Services" at the conference entitled "Achieving Success In Evolving Power Markets," sponsored by EPRI, Houston, 1997, (co-presenter with Charles Clark and Laurence Kirsch).

Speaker on the topic of "Incorporating Transmission Incentive Rates" at the conference entitled "Developing and Implementing ISO Rates and Structures" Washington D.C., 1997.

Speaker and panelist on the topic of "The ISO: Efficient Organization of Power Markets" at the Rate Symposium, sponsored by the University of Missouri, St. Louis, 1997.

Speaker on the topic of "Transmission Pricing Strategies" at the conference entitled "Pricing Strategies In Electric Power," Chicago, 1996, (co-presenter with Keith R. Calhoun).

Lecturer on the topic of "Long and Short-Run Marginal Costs for Transmission and Distribution Services" at the workshop on estimating economic costs, sponsored by EPRI, Denver, 1996.

Presenter on the topic of "Costing and Pricing Transmission," at the workshop for the Transmission Pricing Task Force of the Southwest Power Pool, sponsored by EPRI, Kansas City, 1996.

Speaker on the topic of "Designing Rates and Services for Restructuring Electric Utilities" at the conference entitled "Performance-Based Pricing," Washington D.C., 1996 (co-presenter with Douglas Caves).

Speaker on the topic of "Projecting Wholesale Prices" at the conference entitled "*Achieving Success In Evolving Electric Markets,*" *Indianapolis, 1996.*

Chair of the session entitled "Market Coordination Functions," at the conference entitled "Achieving Success In Evolving Electric Markets," sponsored by EPRI, Atlanta, 1995.

Speaker on the topic of "Evolving Power Markets" at the conference entitled "Innovative Rate Design," sponsored by EPRI, 1994.

Speaker on the topic of "Evolving Power Markets Abroad" at the conference on "Real-time Pricing and C-VALU," sponsored by EPRI, Minneapolis, 1994.

Speaker on the topic of "Efficient Transfer Pricing of Generation and Transmission Services of Integrated Electric Systems" at the annual conference of the Model Users Forum of *Regional Economic Models*, Atlanta, 1993.

Speaker on the topic of "Changing Overseas Power Markets" at the conference entitled "Real-Time Pricing," sponsored by EPRI, New Orleans, 1993.

Speaker on the topic of "Secondary Impacts on Utility Profits, Impacts of New Business Locations" at the conference entitled Model Users Forum of *Regional Economic Models*, 1992.

Served as Session Chair or Reviewer at the Annual Conference of the Advanced Seminar in Regulatory Economics, Rutgers University, Newark, 1986 and 1990-1993.

Speaker on the topic of "Market Segmentation and Pricing Efficiency" at the conference entitled "Innovative Rate Design," EPRI, 1988.

Special Assignments and Professional Associations:

Negotiation of a Purchase Power Agreement for generation services between the Power Delivery and Power Supply *divisions, for a major investor owned* electric company, 2001.

EPRI Advisory Committee on Market Management, 1992-1994.

Special Assignment to Southern Company's *Management Information Reporting System* (MIRS) project focused on the implementation of transfer pricing for generation and transmission services, 1993.

Evaluation Working Group, Southern Company: Initiation and coordination of a system-wide group focused on the evaluation of marketing plans. The group was charged with reaching a common conceptual design and methodology to estimate marginal costs and evaluate marketing programs and demand side options, 1990.

Economics Panel, Southern Company: Economics panel tasked with the development of business scenarios for use in long-term planning. The panel identified ranges of values for key exogenous economic drivers and assumptions, 1986-1987.

Load and Energy Forecast Review Committee, Alabama Power Company, 1991-1993.

National Association of Business Economists, 1987-1992.

Utility Planning Model Users Group, Southern Company, 1986-1987.

American Economic Association.

International Association of Energy Economists.

Board of Directors, New England Economic Project, Model Manager, 1981-1983.

Economics Committee, National Association of Regulatory Utility Commissioners, 1980-1983.

Policy Advisory Committee, Regional Energy Facility Siting Study, a project funded by the Nuclear Regulatory Commission, 1981-1982.

Testimony before Regulatory Agencies:

Docket 2008-00408: Direct testimony regarding regulatory policy concerning employment of smart grid technologies in view of provisions of the Energy Independence and Security Act of 2007, before the Kentucky Public Service Commission on behalf of East Kentucky Power Cooperative, January 2009.

Docket 080366-GU: Direct testimony regarding cost of capital and rate of return recommendation for determining retail natural gas prices, before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, December 2008.

Docket 080366-GU: Direct testimony regarding expected inflation and escalation factors for determining retail natural gas prices, before the Florida Public Service Commission, on behalf of Florida Public Utilities Company, December 2008.

Docket E015/GR-08-415: Direct and rebuttal testimony regarding the long-term energy and load forecast methodology, on behalf of Minnesota Power Company, before the Minnesota Public Utilities Commission, October 2008.

Docket PUE-2008-00046: Direct testimony regarding cost allocation and principles based on marginal costs, before the Virginia State Corporation Commission, on behalf of Steel Dynamics Corporation, September 2008.

Docket 070304-EI: Rebuttal Testimony before the Florida Public Service Commission regarding return on equity for the determination of retail rates, January 2008.

Docket 070304-EI: Direct Testimony before the Florida Public Service Commission regarding cost of capital and return on equity, on behalf of Florida Public Utilities Company, for the determination of retail rates, October 2007.

Docket 070108-EL: Testimony before the Florida Public Service Commission regarding a generation power supply agreement for long-term electricity service requirements, May 2007.

Docket 060001-EL: Testimony before the Florida Public Service Commission in support of a power procurement process and long-term full requirements contracts, November 2006.

Testimony and report before the Ontario Energy Board regarding the cost of capital for local distribution companies in Ontario, Canada, September, 2006.

Docket ER-2006: Testimony before the Missouri Public Service Commission with regards to performance assessment, cost benchmarking, and capital risks attending electric utilities, on behalf of Kansas City Power and Light, January 2006.

Docket ER-2006: Rebuttal testimony before the Missouri Public Service Commission with regards the recognition of performance in the determination of retail prices, on behalf of Kansas City Power and Light, August 2006.

Docket 06-KCPE: Testimony before the Kansas Corporation Commission with regards to performance assessment, cost benchmarking, and capital risks attending electric utilities, January 2006.

Docket 050827-EI: Panel testimony before the Florida Public Service Commission regarding a regulatory phase in plan of the contract terms for generation services for the determination of retail rates, November 2005.

Docket 2006 EDR: Testimony before the Ontario Energy Board regarding the methodology and recommendations for electric distribution cost estimation and benchmarking of the local distribution companies of the Province of Ontario, January 2005.

Docket 040216-GU: Panel testimony regarding the cost of capital before the Florida Public Service Commission for the determination of retail rates, September 2004.

Docket 030438-EI: Panel Testimony before the Florida Public Utilities Commission regarding the cost of capital for determining retail electricity prices, economic costs of distribution services, and cost performance, February 2003.

Testimony and discussion on financial implications and risks under open access transmission, before the Energy Regulatory Office, Warsaw, Poland, September 1998.

Docket 9335-CE-100: Testimony regarding the implications of current and emerging competition on transmission reliability and planning, with particular focus on the Wisconsin western interface. The docket was a request before the Wisconsin Public Service Commission for Certificate For Public Convenience and Necessity (CPCN) to begin construction of a combined-cycle cogeneration plant in northeastern Wisconsin, July 1997.

Docket R-832331: Testimony regarding cost of capital for the determination of retail gas services of UGI Corporation, on behalf of the Consumer Advocate for the State of Pennsulvania, before the Pennsylvania Public Utilities Commission, August 1983.

Docket U-5724: Testimony regarding the cost of capital for Upper Peninsula Power Company in its application before the Michigan Public Service Commission for an increase in prices for retail telephone service, July 1978.

Docket 80-47: Testimony regarding projections of electricity demand, in the Commission's generic inquiry into the future demand for power, before the New Hampshire Public Utilities Commission, May 1981.

Docket 80-24: Testimony on the cost of capital in the application of Wilmington Suburban Water Corporation to determine prices for retail water service, before the Delaware Public Service Commission, November 1980.

Docket DR 80-23: Testimony on the cost of capital in the application of New England Telephone Company for an increase in retail rates, before the New Hampshire Public Utilities Commission, February 1980.

Docket DR 80-218: Testimony on the cost of capital in the application of Hudson Water Company before the New Hampshire Public Utilities Commission for an increase in prices for retail water service, February 1981.

Docket DR 81-86: Testimony on the cost of capital in the application of Granite State Electric Company before the New Hampshire Public Utilities Commission for an increase in prices for retail electricity service, July 1981.

Docket DR 79-187: Testimony on the cost of capital in the application of Public Service Company of New Hampshire before the New Hampshire Public Utilities Commission for an increase in retail electricity prices, February 1980.

Docket DR 80-104: Testimony on the cost of capital in the application of Northern Utilities before the New Hampshire Public Utilities Commission for an increase in prices for gas service, October 1980.

Docket DR 81-87: Testimony on the cost of capital in the application of Public Service Company of New Hampshire before the New Hampshire Public Utilities Commission for an increase in prices for retail electricity service, July 1981.

Docket U-5955: Testimony on the cost of capital in the application of Michigan Consolidated Gas Company before the Michigan Public Service Commission for an increase in prices for retail gas service, March 1979.

Docket U-6022: Testimony on the cost of capital in the application of Michigan Gas Utilities Company before the Michigan Public Service Commission for an increase in prices for retail gas service, June 1979.

Docket DE 81-312: Testimony on the topics of Demand Analysis (Technical Paper J) and Demand Elasticity (Technical Paper S) in the Commission's investigation of future supply and demand for electricity, New Hampshire Public Utilities Commission, October 1981.

ER 81-70, 71: Testimony on the cost of capital in the application of New England Power Company before the Federal Energy Regulatory Commission for an increase in prices for wholesale generation and transmission service, August 1981.

Docket U-5452: Testimony on Gas Rate Design in the application of Southeast Michigan Gas Company before the Michigan Public Service Commission for an increase in prices for retail gas service; June 1978.

RC2

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates

EXHIBIT "RC 2"

This is a copy of the Study of the Cost of Capital and Rate of Return Recommendation marked Exhibit **"RC 2"** mentioned and referred to in paragraph 8 of my Affidavit.

SWORN TO by the deponent)
Robert J. Camfield)
this 7th day of May)
2009, before me:)

Robert J. Camfield

Jerie L. Watson
NOTARY PUBLIC

I, Jerie L. Watson, Notary Public in and for the State of Wisconsin in the United States of America, do hereby DECLARE that on the 7th day of May 2009, personally appeared before me a male person who identified himself to be the within named ROBERT J. CAMFIELD and did in my presence sign and execute the Affidavit as and for his free and voluntary act and deed.

IN TESTIMONY WHEREOF I have hereunto subscribed my name and affixed my seal of office this 7th day of May, 2009.

Jesse L. Watson
Notary Public
My commission expires:
9/5/10

Exhibit RC-2

REPORT

STUDY OF THE COST OF CAPITAL
and
RATE OF RETURN RECOMMENDATION

offered for the consideration of:

THE BARBADOS LIGHT & POWER COMPANY LIMITED

prepared by:

Robert J. Camfield

with the assistance of:

Bruce R. Chapman

Michael T. O'Sheasy

Christensen Associates Energy Consulting, LLC

Economic Consulting and Strategy

May 20, 2008

0608

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EXECUTIVE SUMMARY

This report ("Report" or "Study") presents our analysis of the *Cost of Capital* for The Barbados Light & Power Company Limited ("BLPC," "Company," or "Barbados Light and Power") and provides recommendations regarding the *Rate of Return* and *Return on Equity*. The report is intended to assist BLPC in its rate review submission to the Fair Trading Commission focused on the required revenue level and retail electricity prices of BLPC.

The report reviews cost of capital principles and theory, discusses the workings of capital markets, and presents the empirical results of cost of capital study. The report concludes with a summary of the study findings, including the rate of return recommendation.

The *Cost of Capital* of BLPC includes the rate of interest on the Company's outstanding long-term debt, and the cost rate of common equity contributed by investors. Together, the debt interest rate and equity return rate yield the overall *Weighted Average Cost of Capital* ("WACC"), stated on a traditional capital structure basis. When the long-term debt and common equity balances are combined with other contributed capital including *Customer Deposits, Accumulated Deferred Income Taxes, Deferred Investment Tax Credits* and the *Manufacturers' Allowance*, the WACC reflects a regulatory capital structure, and can be referred to as the overall *Rate of Return* ("ROR"). Cost of capital and rate of return are an essential part of regulatory governance. Because a utility's rate base often constitutes a large cumulative investment amount, comparatively small changes or adjustments to the allowed rate of return can translate into a significant change in operating income and revenue level.

The analyses and recommendations of the Cost of Capital study are a result of applying well-recognized principles and methods. In particular, the cost of capital approach used herein adheres closely to Fair Rate of Return Principles and takes account of the business context and capital needs of BLPC in order to continue to serve Barbados with reliable power supply. The application of these principles results in *just and reasonable* electricity prices, where the interests of retail consumers and investors who commit capital for the convenience and necessity of the public are appropriately balanced. The main features of Fair Rate of Return principles include:

1. Returns Equivalent to those Realized On Investments of Comparative Risk: As codified in U.S. Supreme Court decisions, capital commitment by investors for the convenience and necessity of the public is entitled to returns equivalent to those realized on investments of comparable risks.
2. Maintenance of Financial Integrity: The process of regulatory governance, as a practical matter, must result in a flow of revenue sufficient to cover all prudently incurred costs associated with providing utility services and an adequate return on the capital committed by investors. In turn, adequate return on capital preserves and maintains the financial integrity of the Company.
3. Ability to Raise Capital On Fair Terms When Needed: The utility and its investors are entitled to adequate returns on capital so that the utility can raise capital as necessary to provide utility services, on fair and equitable terms and conditions—*i.e.*, an acceptable interest rate level.

The application of Fair Rate of Return principles is amply underscored and provided for in the immediate study and its application. To this end, it is useful to highlight key findings, as incorporated within the overall Rate of Return recommendations, as follows:

- Capital Structure: Adopt a regulatory capital structure that includes 35% debt and 65% equity participation in total capital, *when stated on a traditional basis*. This policy-based capital structure constitutes a significant departure from the Company's observed capital structure for 2007, with equity participation of 78.6%.
- Regulatory Capital Structure: Develop a regulatory capital structure that includes traditional and non-traditional contributed capital. The regulatory capital structure includes balances covering *customer deposits*, and *deferred manufacturers' allowance*.

- Debt Cost Rates: Recognize the long- and (when relevant) short-term debt cost rates that cover the outstanding debt of BLPC.[1] For determining the weighted average cost of capital, interest costs reflect the observed interest rates in the case of a historical test year or expected interest rates in the case of a projected test year.
- Preserve Income Tax Incentives: It is important that regulatory policy adhere to and preserve the investment incentives, including the intended strength of incentives, of the taxing authority. This feature is manifested in the cost rate applied to the balances of manufacturers' allowance included within the regulatory capital structure, where the applicable cost rate is set equal to the WACC of 10.61%, for the traditional capital structure including a policy-based debt/equity ratio of 0.54 (debt level = 35%, equity participation = 65%).
- Return on Equity: Utilize a full complement of cost of capital methods to determine the cost of equity capital for BLPC. Draw upon the experience of capital markets in the U.S., Canada and, if necessary, elsewhere to estimate the cost of capital; and recognize or further investigate the effects of size on the equity cost of capital. The allowed Return on Equity should incorporate sovereignty risk differences between Barbados and established nations with highly developed capital markets.

Overall Rate of Return and Capital Structure

Shown below is the overall target Rate of Return Recommendation for BLPC, for the year 2006.

[1] Because retail prices are set for future timeframes, it may be appropriate to utilize estimated interest rates in the future, as the basis for determining interest rates for debt, particularly for short-term debt. Depending on timeframe and circumstances, the expected value of future interest rates can depart significantly from historical rates. However, the observed interest rates of the Company's debt appear to be a close approximation to future interest costs of outstanding debt over the foreseeable future. Estimates of future interest rates can be obtained by deriving future spot rates from observed forward rates.

RATE OF RETURN RECOMMENDATION: WEIGHTED AVERAGE COST OF CAPITAL FOR REGULATORY CAPITAL STRUCTURE, 2007

Capital Component	Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$188,374	31.32%	5.25%	1.65%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$349,837	58.17%	13.50%	7.85%
Customer Deposits	$20,010	3.33%	6.46%	0.22%
Deferred Investment Tax Credits	$30,099	5.00%	10.61%	0.53%
Deferred Manufacturers' Allowance	$13,052	2.17%	10.61%	0.23%
Total	$601,371	100.00%		10.48%

As can be observed, the regulatory capital structure includes 31.3% debt, 58.2% equity, and non-traditional components totaling 10.5%, including customer deposits, accumulated investment tax credits and manufacturers' allowance. Customer deposits represent 3.3% of contributed capital, with a cost rate of 6.46%, which is the effective rate of interest paid by BLPC to retail deposits retained by the Company. Accumulated investment tax credits make up 5.0%, while balances of deferred manufacturers' allowance occupy 2.2% of the regulatory capital structure. Both carry a cost rate of 10.61% which, as mentioned above, is set at the overall weighted average cost of capital based on a capital structure stated on a policy basis and includes equity participation of 65%.

Long-Term Debt Cost Rate

The Fair Trading Commission should utilize the observed cost rate for the Company's outstanding balance of long-term debt of 5.25%. This cost rate is derived from the actual interest carrying charges on the Company long-term debt, which carried an average balance of $115 million BBD during 2007.

Short-Term Debt Cost Rate

Within the 2006 timeframe, BLPC carried no short-term debt balances. However, as a matter of policy, the cost rate for short-term debt should be set at the prevailing or expected interest rate(s) associated with the Company's balances of short-term debt, which may consist of credit balances owed to equipment vendors, commercial paper, promissory bank loans, or lines of credit where often the effective interest rate is linked to the well known London InterBank Offer Rates ("LIBOR").

Return on Equity
We recommend a rate of return on equity for BLPC of 13.50%. This result comes about from the application of four methods to estimate the cost of capital for samples of U.S. and Canadian utilities and a sample of low-risk comparatively small-sized U.S. non-utility companies. The results of these four methods are supplemented by consideration of the earnings premium that BLPC may likely require in order to fully satisfy the capital costs on investments of comparable risks. Specifically, the comparatively small size of the Company, as well as its role as the primary supplier of generation and power delivery services to the increasing electricity demand of an island economy, induce providers of funds to require an earnings premium relative to larger firms in continental markets.

We recommend that BLPC ask the Fair Trading Commission, in its deliberation of cost of capital issues, to endorse the broad-based approach to cost of equity estimation applied in this study. Specifically, cost of capital cannot be readily estimated precisely, such that it is best, as a matter of policy, to draw upon several well-recognized cost of capital methods, together referred to as the *Cost of Capital Toolbox*. This approach can cover a range of cost of capital methods including the *Capital Asset Pricing Model, Discounted Cash Flow*, and *Risk Premium Analysis.*[2] The *Cost of Capital Toolbox* also includes *Comparable Earnings*, based upon historical realized returns of comparable-risk companies, where such returns serve as a basis of future earnings performance.

The table below summarizes the estimated cost of common equity for each of the four identified methods, as applied to three U.S. samples of comparable risk utilities and non-utility companies or "peer groups," and to two samples of Canadian utilities listed on the Toronto Stock Exchange ("TSX"). These samples[3] provide a broad base of financial and equity market experience of utilities and comparable low-risk non-utilities that operate on the North American continent. The risk levels of the sample

[2] Other approaches are available including Factor Models and *Arbitrage Pricing Theory* ("APT"), and well-known assessment techniques such as the Sharpe Ratio.

[3] Samples such as these underlie return on equity estimates incorporated into our studies for other clients.

companies are roughly comparable to those of BLPC, although Barbados Light and Power is confronted with unique business circumstances and is also comparatively small with reference to the companies that comprise the five samples.

MARKET-BASED ESTIMATES OF THE COST OF COMMON EQUITY FOR COMPARABLE RISK COMPANIES

SAMPLES:	CANADA		UNITED STATES		
METHODOLOGY	1	2	Mid-Sized Electric Utilities	Gas Distribution Utilities	Low Risk Non-Utility Companies
Discounted Cash Flow					
Single-Stage Model			10.32%	10.86%	
Capital Asset Pricing Model					
Classsical Single-Factor Model	10.39%	10.60%	11.28%	11.32%	10.35%
Risk Premium					
CAPM-based, Size Premia Adjusted			12.07%	12.12%	12.71%
Realized Market Returns					
5- and 10-year Timeframes	13.36%	16.07%	10.41%	9.34%	10.75%

Thus, the range of estimates is 9.34% to 13.36%, excluding the aberrational 16.07% in realized returns for the second Canadian sample, with an average 11.16%. The cost of capital study accounts for BLPC's small size, smaller than virtually all of the firms used in the utility sample groups above, and its location within a sovereign island nation and thus independent of the meshed integrated nature of the continental energy system within which sample utilities operate. The cost of capital and return on equity recommendation incorporates factors that affect the cost of equity, including small size risk, sovereignty risk, and adjustments for quarterly dividends, issuance costs, and differences in equity participation in total capital. In total, these factors amount to a low and high range of 2.05% to 2.71%. Adding these factors to the average of the market cost of equity estimates obtains a range of 13.18% to 13.85% with a mid-point of 13.51%, for the return on equity for BLPC. With this range in mind, and given the challenges in precisely determining an adjustment specific to the Company, we recommend a common equity rate of return of 13.50%. This estimate of cost of equity represents a conservative yet reasonable level of allowed return on the capital committed by equity investors to The Barbados Light and Power Company Limited and to Barbados.

INTRODUCTION

This report develops the rate of return recommendation for submission to the Fair Trading Commission in determining the required revenue level and retail prices for The Barbados Light & Power Company Limited ("BLPC" or "Company"). The recommendation for the rate of return is based on the Company's cost of capital; estimates of which are presented in this report. The report reviews cost of capital principles and theory, discusses the workings of capital markets, and presents the empirical results of the cost of capital study.

The *Cost of Capital* is the composite interest rate of the debt and equity contributed by investors to underwrite a utility's rate base, which includes net depreciated capital, inventory and stores, and working capital. The composite cost of capital is the Weighted Average Cost of Capital ("WACC"). For regulatory purposes the WACC is referred to as the overall *Rate of Return* and is expressed as an annual percentage interest rate applied to the utility rate base, and is set by the regulatory authority. Determining the overall rate of return is very important. Because a utility's rate base often constitutes a large cumulative investment amount, comparatively small changes or adjustments to the allowed rate of return can translate into significant changes in allowed operating income and revenue level.

PART I: FOUNDATIONS FOR THE COST OF CAPITAL

DEFINITIONS

The *Cost of Capital* is the underlying interest rate used by investors to discount the expected benefit flows of capital resources including returns to financial assets,[4] and is sometimes referred to as the rate of discount, or simply the discount rate. The cost of capital is the compensation required by investors for postponing consumption, for

[4] Financial assets are one form of capital. More generally, *Capital* refers to economic resources of a durable nature that contribute to the production of goods and services, or may provide services directly. Capital resources of an economy are readily at hand; examples include manufacturing equipment, software, commercial buildings, residential dwellings, streets and highways, airports and, importantly, the accumulation of skills and knowledge of the workforce. Capital is accumulated savings over time, where savings refers to the proportion of the output of an economy that is not consumed as current goods and services. Essentially, savings is the share of output held back and invested in—*i.e.*, put into—capital resources. The cumulative level of investment over time, covering decades, constitutes the capital stock of an economy and the society that it serves.

expected inflation, and for exposure to capital risks of various dimensions, where such risks are specific to investment vehicles.

The cost of capital is determined by the demand for capital, supply of savings, expectations of inflation, and perceptions of risks harbored by participants in capital markets. The demand for and supply of capital are determined by expectations of future levels of economic activity, while expected inflation is driven largely by monetary policy over the relevant timeframe. Perceptions of risk, in turn, cover many dimensions including uncertain government policy, the effects of natural phenomena such as weather including violent storms, droughts, and floods; and, in some regions of the world, war and civil unrest. The cost of capital—the discount rate stated in nominal terms—increases with rising demand for capital, with expectations of higher rates of inflation, and with heightened perceptions of risk. Arguably, risk is the key contributing factor for the estimation of the cost of capital.

Financial assets include a multitude of debt vehicles, equity, and derivatives, and are tailored to participants of capital markets including household, small business, corporate, and government segments. Participants across these segments—*i.e.*, investors including lenders and holders of common and preferred stock— can supply capital while other participants (such as borrowers and common stock issuing companies) demand capital. Commercial banks, credit unions, finance companies, capital exchanges, and investment banks serve as intermediaries that provide the institutional means that facilitate the interaction and linkage of the supply and demand sides of financial markets. These functions essentially include lending, borrowing, and the issuance of equity vehicles. Banks and credit unions borrow (and store) financial assets that in turn are invested in the form of debt and, to a lesser extent, equity. Household debt vehicles include, for example, personal loans covering appliances, household services, and credit card mechanisms through finance companies and banks, and real estate and so-called home equity loans. Business loans include short-term loans and lines of credit with banks, inventory financing through business wholesalers, and commercial paper of various terms and credit risk ratings. Corporate debt can be in the form of lines of credit with banks, and mortgage and debenture bonds, while government debt can be in the form of revenue bonds of cities, and short- and long-term debt of various terms.

Equity (or, *Common Equity*) refers to net accumulated value of the contributed capital by investors. Generally speaking, equity is in the form of common and preferred stock and includes the accrual of retained earnings, where the investor, through the purchase of stock, assumes a share in the ownership of a corporate entity. In some cases, debt instruments can participate in equity returns and may also have rights of conversion to common stock. Derivatives are financial instruments whose value depends on investor expectations regarding the inherent value of the underlying assets. Derivatives, common forms of which include options and forward contracts, provide a basis for speculation and for hedging of risk associated with the value of the asset.

The cost of capital associated with financial assets is determined by investors and, in the large, by individuals and entities (including government entities) that provide savings and thus the accumulation of capital within the economy. In the case of financial assets, expected benefits are in the form of future cash flows including interest payments, dividend payments, market appreciation, and return of principal. When investors supply funds to entities such as utilities and governments, not only are they postponing consumption—giving up the value obtained from alternative expenditures—they are also exposing funds to the potential devaluation from ongoing inflation as well as to various uncertainties and risk attending future cash flows. Investors are willing to incur these risk factors only if they are adequately compensated. While the market prices of other inputs including labor, materials, and energy can be easily verified, the cost of capital—essentially, the price of capital—is not easily discerned and, all too often, requires estimation through the cautious application of analytical methods. The cost of capital remains positive in the absence of inflation and risks, as savers require compensation for foregoing the right to use the funds saved for consumption of goods and services—essentially, the time value of money.

In addition to the global risks alluded to above (weather, government policy, etc.) dimensions of risk also cover idiosyncratic factors associated with specific capital resources, such as those of individual entities or companies. Accordingly, financial markets will re-price downward the bonds of a private company, should the *current* financial condition of the company suddenly decline. Essentially, the decrease in the company's current condition reflected as reduced interest coverage—causes the expectation of the future condition of the company also to decline. Expectations of future financial conditions (possible states) of the specific company are idiosyncratic risks. Because cost of capital rises with increased risks, the price of the bonds declines. Bond prices and discount rates, in the form of the net interest rates or bond yields (and yield to maturity), move in opposite directions; bond yields increase as bond prices decline, and decrease as bond prices rise.

FINANCIAL MARKETS

To facilitate the commitment of capital (investment) by savers and their agents to the firm, the firm offers property rights, including bonds or promissory notes to debt holders and shares of stock to equity investors. These property rights define the commercial terms and conditions under which savers and their agents, as investors, commit capital. Property rights are capital (financial) assets, and are generally tradable in organized financial markets or on an *over-the-counter* basis. Financial assets are claims on the income of the firm as compensation for the commitment of capital, and are the financial obligations of the firm. Shares of stock constitute ownership in the firm.

In the case of long-term debt—*i.e.*, mortgage bonds, debentures, and long-term notes—the interest on the principal (face) amount of a bond (debt) or the coupon rate on the share of preferred stock defines the level of compensation. Often, the interest rate is a predefined annual rate that remains fixed over the term of the debt. However, long-term debt instruments can have a number of other provisions that, in essence, provide for more complete contracting by managing risks through risk sharing between the debt holders and the borrower (the firm). These provisions can include: 1) adjustments to the rate of interest to reflect contemporary market conditions *and* rates of inflation, 2) participation in the earnings of the firm, 3) conversion rights, and 4) voting rights in the management of the firm.

In the case of short-term promissory notes, agreements with commercial banks define the mechanism by which interest, stated in dollars, is determined. Often, the commercial terms of promissory notes define interest to be paid monthly on the outstanding daily balance (principal outstanding). The rate of interest applied to the outstanding balance is typically tied (indexed) to the interest rate on obligations of some widely known financial market—say, the London Interbank Offer Rate (LIBOR) or Fed Funds—which also varies daily or monthly.

Common stock property rights are somewhat different from other financial obligations because, as owners of the firm, the returns to shareholders are residual amounts following the compensation of other resources employed by the firm including debt obligations. Common equity is essentially compensated last, and bears the burden of much of the business, regulatory, and financial risks of the firm. For this reason, common equity is, in virtually all cases, more costly than other forms of financial instruments.

As with many other markets, capital markets have primary and secondary dimensions. Primary markets are the institutions and processes that facilitate the initial sale of the financial obligations of the firm to initial investors, whereas secondary markets are structured market processes that provide the means by which investors can purchase and sell existing rights, including shares of stock and debt obligations. Financial instruments can assume many forms, and debt securities (bonds) and equity shares are actively traded in financial markets, which are generally considered to be highly liquid and competitive. However, to the degree that financial obligations: 1) carry specialized and non-common commercial terms, and 2) secondary—and to a lesser extent, primary—markets are less liquid, holders of such obligations assume higher risks, other factors held constant. This is the case where the pool of buyers and sellers is limited and the volume of transactions is comparatively small. Relatively low levels of liquidity imply higher transaction costs and risks to investors, which translates directly into higher costs of capital to the firm.

Competition is a term that describes some markets, and markets are said to be competitive if certain conditions exist. Markets can be characterized as competitive if they involve: 1) a very large number of buyers and sellers, 2) information relevant to the determination of prices is readily available, complete, and not costly, and 3) transactions costs are low. Because of the workably competitive nature of financial markets, arbitrage opportunities are more or less exhausted. This means that, for both primary and secondary markets, financial property rights trade at levels (prices) such that perceived risks and opportunities for prospective returns to capital are appropriately balanced and approximate those of other investment opportunities.

Thus, above-normal returns, which implicitly include compensation for risks, cannot be seemingly realized by investors over prospective periods in systematic fashion.

Under the assumption of market efficiency, the competition inherent in U.S. and worldwide financial markets implies that the prices of common shares (share prices) and bonds are at a level that reflects the opportunity cost of capital. As an example, assume that the perceived risks attending the returns to common shareholders of Firm A are equivalent to those of Firm B and other firms. If the share prices of Firm A suggest a market return of 10%, while the prices of Firm B and other firms of comparable risks suggest (allow) market returns of 13%, the market price of Firm A will fall to a level that provides a basis for market returns of just 13%, prospectively. A price that allows for a 10% prospective market return is insufficient in the presence of opportunities for a market return of 13% on alternate investments of comparable risk. Essentially, the 13% market rate of return on investment alternatives constitutes the opportunity cost of capital. Most remarkable is the expedience—literally, in minutes for highly liquid financial markets—with which share prices adjust to levels that appropriately balance prospective returns to equilibrium levels *based upon perceptions of risks*. In short, equivalent and comparable risks translate directly into comparable rates of return, which is the cost of capital of common shareholders in—and thus of—the firm.

As mentioned early on, the cost of capital is a function of the demand for and supply of capital, investor expectations of inflation, and investor perceptions of risks. Because the conditions of demand and supply as well as expectations of inflation are more or less common to financial markets at any point in time, financial vehicles are differentiated by risks. Hence, the expected returns and prices of bonds and common shares (normalized for denomination and size) at any point in time are largely if not exclusively differentiated by perceptions of risk.

In summary, whereas the cost of skilled labor, materials and supplies, and fuel used in the process of providing utility services are expressed in money terms, the cost of capital is expressed as an interest rate, typically shown as an annual percentage of investment. This means that the costs of the capital resources employed by BLPC, including generation equipment, power delivery systems such as transformers and lines, meters, trucks and vehicles, computer systems, software, office facilities and buildings, inventory and stores, and land—essentially, the rate base of BLPC—are reflected as annual carrying charges. The cost of capital for BLPC—or perhaps more accurately, the *cost rate of capital*—is referred to as the *required rate of return* (%) on the capital resources committed by investors to the Company, where capital is valued at either original cost or fair value.[5]

PRINCIPLES UNDERLYING FAIR RATE OF RETURN

Legal guidelines for rate of return utility regulation of the North American Continent have been discussed extensively, and are delineated by key decisions of the legal authorities in the U.S. and Canada. As a point of departure, the statutory principles of rate of return for public utilities rest substantially with two decisions of the Supreme Court of the United States. In the *Bluefield Water Works and Improvement Co. v. Public Service Commission of West Virginia* case (262 U.S. 679, 1923), the U.S. Supreme Court set forth its view on fair rate of return, as follows:

> ...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 risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises 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. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.

A second landmark decision of U.S. Supreme Court echoed and expanded upon the fair return standard established by the "Bluefield" decision cited above, for capital committed to public utilities. This second decision is the *Federal Power Commission*

[5] For the determination of setting retail utility prices in the U.S. and elsewhere, the regulatory convention is to value the capital of public utilities at original cost.

v. Hope Natural Gas Company case (320 U.S. 391, 1944); a relevant passage of this latter decision is as follows:

> From the investor or company point 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 return 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 attract capital.

These longstanding decisions provide the recognized framework for the fair rate of return on capital committed by investors to public service. In these decisions, the U.S. Supreme Court codified, in clear and readily understandable terms, a statutory benchmark that serves as the basis to set fair and equitable prices for retail public services such as natural gas, while also providing a fair rate of return on the capital provided by investors. Though they reach back many years, these decisions remain to this day the cornerstone for the determination of rate of return requirements. The challenge for regulators, regulated utilities, and interested parties to regulatory proceedings is to operationalize these principles in contemporary regulatory processes.

As noted by Professor Roger A. Morin in his testimony before the New Hampshire Public Utility Commission:

> Subsequent cases have reaffirmed the standards established by the Bluefield and Hope cases.[6] In the Permian Basin Area Rate Cases (390 U.S., 747, 1968) the U.S. Supreme Court stressed that:
>
>> 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

[6] As discussed in Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, Public Utilities Report Inc., 1994, pp. 10-11, these cases include *Federal Power Commission v. Memphis Light, Gas & Water Division* (411 U.S. 458, 1973), *Permian Basin Area Rate Cases* (390 U.S., 747, 1968), and *Duquesne Light Company et al. v. Barasch et al.* (488 U.S. 299, 1989).

> to the relevant public interests, both existing and foreseeable. The court's responsibility is not to supplant the Commission's balance of these interests with one more nearly to its liking, but instead to assure itself that the Commission has given reasoned consideration to each of the pertinent factors.

Further down this path, the U.S. Supreme Court, in its decision in *Duquesne Light Company et al. v. Barasch et al.* (488 U.S. 299, 1989), explicitly recognized risks associated with changes in regulatory governance. In addition, key decisions in Canada align with the expressed views of the U.S. Supreme Court cited above.[7]

UTILITY REVENUES, WEIGHTED COST OF CAPITAL

Public utilities such as BLPC utilize and employ substantial levels of capital resource inputs to provide delivery services. As mentioned, total net invested capital is the basis for setting regulated prices and is the primary component of a utility's rate base.

In general, the flow of revenues less the costs of non-capital inputs to the firm such as operating expenses provides a level of dollar returns to capital, in the form of operating income. If outcomes match expectations, investors realize returns equivalent to the overall cost of capital. As discussed more fully below, the overall cost of capital, often referred to as the *weighted average cost of capital* ("WACC") and expressed in percentage terms, recognizes and is based on the pool of financing vehicles used by the utility to underwrite the capital that it employs, as reflected as rate base. In summary, the WACC is the composite weighted cost of the financing vehicles including short-term debt, long-term debt such as mortgage bonds, preferred stock, and common stock.[8] These financing vehicles are property rights and

[7] Specifically, the perspectives expressed within selected Canadian decisions including *Northwestern Utilities v. City of Edmonton* (S.C.R. 186, 1929), and *British Columbia Electric Railway Co. v. Public Utilities Commission of British Columbia* (S.C.R. 837, 1960) amply demonstrate a similar line of reasoning and guideline for Canadian regulatory authorities to that of the U.S. Supreme Court decisions, for the setting of the fair rate of return level for utilities. For a more complete discussion of legal guidelines and landmark court decisions, please reference Roger Morin, *Regulatory Finance*, and Charles F. Phillips, *The Regulation of Public Utilities*, 1988.

[8] As mentioned earlier, the capital structure and overall rate of return, for purposes of regulation, can also include customer deposits and, under accrual accounting, balances of various deferred accounting items such as income taxes and investment tax credits.

constitute the financial contracts between savers and the firm, including government entities and private companies.

As mentioned above, utilities must compete with all other entities in the free open market for the input factors (labor, materials, and energy inputs). The prices of these inputs are set in the marketplace,[9] and the costs of these inputs that are incorporated into the total costs and required revenues. Likewise, prices for capital resources such as equipment, facilities, software, inventories, and working capital are also set by markets. Since utilities including BLPC must directly or ultimately attract capital through open financial markets, there exists a market price to pay for the capital they require—in short, the market cost of capital that implicitly exhausts all opportunities for higher returns, given perceived risks.

REGULATION, DEMAND FOR CAPITAL, CAPITAL ATTRACTION

The cost of capital concept may also be interpreted from the perspective of internal investments and the demand for resources. Regulated utilities accommodate the ongoing and steadily rising demand for services, which involves expanding employment of resources, capital in particular. Senior managers of firms, as agents for the ownership or controlling interest of the entity such as shareholders or a local municipality, are responsible for ensuring that the expected internal returns on incremental capital committed by the firm is equivalent to the cost of capital to the firm—*i.e.*, investors' rate of return requirements The adequacy of the internal returns on incremental investment by electric utilities to fund capital at full opportunity costs, however, is highly dependent upon the soundness of the regulatory governance structure to ensure that the utility has the opportunity to obtain sufficient revenues, which in turn provide adequate returns on new capital.

When the rate of return, as set by regulators, leads to inadequate returns to capital or to the expectation that returns to capital are likely to be insufficient, utility managers

[9] The discussion recognizes that entities including utilities may not participate in workably competitive markets for the various inputs that they require. Along this line, however, it is useful to mention that, worldwide, financial markets are generally considered to be relatively competitive, where the notion of competition implies that the actions and behavior by individual market participants including buyers and sellers have, as a general rule, no significant impact on the market clearing prices or the availability and sale of goods and services. Innumerable examples challenging the assumption of workable competition can be cited. Within capital markets, for example, the sudden sale or purchase of large blocks of shares of a specific entity may have significant impact on the market value of shares.

are understandably reluctant to make investments in infrastructure. Indeed, when the expansion of capital resources occurs under a regulatory requirement including the obligation to serve, the absence of adequate returns implicitly constitutes the confiscation of the capital. Under these regulatory conditions, the utility is forced to provide services that involve new investment, even though adequate returns are not obtainable. The result is a failure of capital attraction by the utility, and the confiscation of capital of investors—an outcome that comes about from the inherent efficiency of competitive capital markets.

Investors, investment rating agencies, investment banks, and commercial bank lenders follow regulatory developments. Anticipating a shortfall of the internal returns to capital vis-à-vis rate of return requirements, capital markets bid down the prices of the outstanding securities of the utility. The reduced market capitalization of the utility constitutes, arguably, the confiscation of the existing capital of holders of the utility's securities. Essentially, the utility has failed to (or simply cannot) attract capital on fair terms—terms that do not cause outstanding investors to incur wealth losses.

In summary, the utility and its managers can often find themselves, as a result of service requirements, forced to invest in real physical assets that are uneconomic from the perspective of the firm and its constituent investors, if the return on incremental investments falls short of the cost of capital.[10] The cost of capital is the minimum rate of return that must be earned on physical assets to justify their acquisition, and thus the regulator must be mindful of the allowed rate of return levels and implement regulatory procedures that provide the utility with an acceptable level of opportunity to realize returns, on the margin, that satisfy the cost of capital—*i.e.*, a rate of return equivalent to that realized on investments of comparable risks. In the context of a binding regulatory constraint, and other regulatory requirements such as obligations to serve, it is necessary and sufficient for the required rate of return on incremental investment to adequately satisfy the opportunity cost of funds. The regulator should set the allowed rate of return equal to the cost of capital so that the utility is free to satisfy its capital needs and service customers at fair prices.

[10] The incremental investment is a particular concern to BLPC and other electric utilities in view of aging infrastructure and the on-going replacement of the capital stock, where the incremental cost of the physical resources can be several times greater than the book value of embedded facilities.

The aforementioned principle and accompanying rule can be illustrated by an example. Suppose a utility with a rate base of \$60 million financed 50% through debt and 50% through equity. Assume that the cost rate of the outstanding debt capital is 7.25%, and that the rate of return on equity capital is 12.0%, giving a weighted average cost of capital of 9.63 %. Suppose further that the regulator sets the allowed rate of return at 8.00%, rather than 9.63%. To fully service the property right claims of both bondholders and shareholders, revenues over operating costs should amount to \$5.8 million annually (*i.e.*, 0.0963 × \$60 million). An allowed rate of return of only 6.81% on a rate base of \$60 million provides returns to capital equal to just \$4.8 million. The returns to capital are sufficient to service the outstanding debt, \$2.2 million (*i.e.*, \$60 million x 0.50 × 7.25 %). However, bondholders have primary claims to the returns to capital, and shareholders residual claims. Hence, the return available to service equity holders is a mere \$2.6 million, allowing for a realized equity rate of return of just 8.8%, a shortfall of 3.2% which translates into a loss to shareholders of \$0.98 million.

As a consequence, share prices are significantly bid down, giving rise to a sharp decline in market capitalization of the firm. The result is a significant wealth transfer from shareholders, as investors, to retail consumers. In short, the capital of investors is confiscated via a failed regulatory governance structure. In addition, the regulatory structure, particularly where the utility has binding service requirements and constraints, causes a breach of fairness criteria and leads to a failure of the utility to satisfy capital attraction standards where capital can be raised at fair and equitable terms. Essentially, the higher cost of debt interest charges is a result of the reduced credit standing in view of the lower levels of interest coverage.

It is useful to pursue this line further and consider the counterfactual case. Specifically, if the allowed rate of return is greater than the cost of capital, the capital investments are undertaken and investors' opportunity costs are more than achieved. Any excess earnings over and above those required to service debt capital accrue to equity holders, resulting in a rise in share prices. In this case, the wealth transfer occurs from electricity consumers to shareholders.

The upshot is that, in the absence of other considerations such as the impact of the incentive properties of a chosen regulatory governance structure, investments and capital expansion are undertaken by the utility without inappropriate and unfair wealth transfers between consumers and shareholders if, and only if, the allowed rate of return is set equal to the cost of capital. In the case of the above example, at an allowed rate of return of 9.63% the expected earnings realized on incremental investments are just sufficient to service both the incremental and outstanding claims of debt and equity holders on the capital returns of the utility, no more, no less. In conclusion, setting the allowed rate of return equal to the cost of capital is the only policy that ensures that necessary investments are made in order to satisfy utility service requirements while also providing fair and equitable returns to investors.

CAPITAL STRUCTURE and WACC for ELECTRIC UTILITIES

Capital Structure refers to the means—*i.e.*, financial vehicles—by which private and public entities underwrite physical capital and other assets. Capital structure can involve several types of vehicles including long- and short-term debt, preferred and preference stock, common equity, and capitalized leases. These traditional types of financial vehicles, for purposes of economic regulation, are often augmented by other sources of funds including customer deposits, and deferred balances for income taxes, investment tax credits and, in the case of BLPC, manufacturer's allowance.

The relevant financial policy issue is the level of financial leverage, measured as the ratio of debt to equity that comprises the capital structure stated on a traditional basis. Because debt is generally less costly than equity, it is appropriate for the firm to underwrite its assets with some degree of financial leverage. The appropriate amount of leverage is a matter of operating and business risk, measured by the expected level and variability (mean and variance) in future operating income. In brief, highly stable flows of operating income (and internal cash), which can be interpreted as the total book returns to capital, provide a basis for the firm to employ higher levels of debt. Higher leverage, however, increases the variability of interest coverage and thus the cost of debt, *and the cost of equity* as a result. Thus, the financial policy issue regarding debt leverage is a matter of determining the level of debt that minimizes the weighted average cost of capital ("WACC"). At low levels of debt, the WACC declines as leverage rises. However, beyond a certain point, the expected level and variability of operating income of the firm relative to equity ownership value begin to rise, causing the WACC to increase. In short, the cost rates of debt and equity are sensitive to the debt and equity participation levels within total capital. The relevant question, then, is: what is the appropriate and acceptable level of leverage, given the inherent business and operating risks of the firm?

Decades back, it was common for electric utilities to underwrite assets with upwards of 60-65% debt and corresponding levels of equity of 40-35%. Currently, however, both mid-sized and large electric utility companies typically finance assets with participation shares of 48-58% debt, and 52-42% equity. The gradual evolution favoring lower levels of debt financing is in response to, and is in keeping with, changes in the electricity services industry. Several recent changes in the business environment facing electric utilities have precipitated the reduction in debt financing by electric utilities. These are: market restructuring involving competitive entry for generation and other unbundled services; sharp increases in input costs; closer integration of electricity services and energy markets generally, where energy commodities reveal much higher levels of price variation and volatility; less restrictive regulatory governance structure, including price cap regulation and earnings sharing mechanisms; and uncertain future requirements for environmental compliance.

As a general rule, the governing regulatory authority should adopt the observed historical or projected capital structure, including regulatory (non-traditional) components, where such result is well aligned with least-cost principles. However, where the observed capital structure constitutes a clear departure from least cost—with unusually high concentrations of debt or equity participation—it may be appropriate for the authority consider the adoption of a hypothetical or imputed capital structure. In addition, in the case of isolated service providers such as utilities like BLPC that operate island power systems, or where the utility is unusually small sized and is susceptible to unforeseen business events that cannot be readily diversified or insured, it may be appropriate for regulatory authorities and the utility to employ a higher concentration of equity participation.

WORLDWIDE CAPITAL MARKETS

Arguably, the most significant recent development in capital markets is the globalization of capital flows that, to a substantial extent, has been facilitated by the vast expanse of electronic media. Today, BLPC and entities worldwide compete for capital resources in the face of vastly expanded opportunities for capital as a result of globalization and reduced barriers to capital flows among nations, and markets with increased return opportunities. As an example of the globalization of the capital markets, net private capital (*i.e.*, debt plus equity) flows to developing countries increased from $188 billion in 2000 to $491 billion in 2005 and to $647 billion in 2006.[11] Equity flows in 2006 comprised $419 billion, nearly 75% of total flows, in sharp contrast to the experience of earlier years. As an example, capital flows into developing countries in 1990 were approximately $60 billion for debt, and $40 billion for equity. Equity flows continue to increasingly dominate the share of total flows, in part due to an abatement in official lending flows. For example, during 2006, official lending actually declined while total flows increased by 17% from 2005 levels. As the 2006 World Bank Report states:

> Demand for emerging market debt and equities remained strong, spurred by improved fundamentals in many developing countries and investors' search for higher yields in an environment where long-term interest rates remain low in major industrial countries, despite higher short-term interest rates.[12]

This trend continues through 2007 and the current period, and it is useful to mention several key findings of the 2007 world bank report cited above, as follows:

- Inflows of capital of developing countries are an increasingly large share of total world capital flows, and their financial positions have steadily improved since the years of very slow growth of 2001-2002. Specifically, equity inflows to developing countries other than China were $94 billion in 2006, and were $6 billion 2001-2002.
- Developing countries have reduced external debt, lengthened maturities, and bought back outstanding debt, often using expanded currency reserves. Net lending from the Paris Club of creditors declined sharply in 2006.
- Equity firms located in developing nations have undergone a vast expansion of cross listing of their equity shares on world exchange markets in order to build channels for expanding capital needs, even when doing so implies that they need to satisfy higher accounting and financial reporting standards.
- Foreign corporations are increasingly borrowing on international markets as a result of favorable interest rates and declining sovereign risk spreads. Additionally, foreign firms are increasingly utilizing advanced risk management tools in order to hedge currency and commodity risks, necessary

[11] Source, The World Bank, *"Global Development Finance: The Development Potential of Surging Capital Flows – Review, Analysis and Outlook, 2006, and "Global Development Finance, 2007,"* hereafter referred to as the *"World Bank Reports"*).

[12] The World Bank Report, 2006, p. 18.

as commodity exports, particularly oil and other natural resources, have assumed a much higher share on a value basis of total exports of developing countries.

The development of global capital markets parallels expanded development of economic activity. Indeed, world GDP expanded 5.3% in 2006. Participating in high levels of economic growth are nations in the South American and Caribbean region, which experienced 4.7% and 5.6% expansion of real activity in 2005 and 2006, respectively, with continued growth of 4.3% projected for the 2007-2009 timeframe.[13]

The development of global financial markets parallels and contributes to expanding economic activity. Global markets and the resulting capital flows are much more integrated now than in previous eras and, as a result, investors have a substantially larger set of opportunities to place capital, including investments in utilities in other energy markets and other regulatory jurisdictions. The emergence and development of robust global capital markets over the past decade, in particular since 2001-2002, has placed BLPC and other utilities within the Caribbean region in the position of competing for capital with developed and other developing countries, as well as the complete gamut of industries seeking capital resources. The global nature of capital affects utilities and is relevant for both debt and equity funding.

Global capital markets today are driven to a substantial extent by institutional investors. Institutions are likely to seek to remain fully invested and seek out "undervalued" assets. Finally, strategic institutional investors, like pension funds, life insurance companies, and sovereign wealth funds are growing in importance in worldwide financial markets. The increasing sophistication of these institutional investors means that they are able to differentiate between country- and company-specific investment opportunities. This translates into investment behavior that pays close attention to the risk profiles of opportunities that they face, including utilities and other energy market equities, when making decisions about strategic placement of funds.

In short, the clear implication is that BLPC and other entities large and small must compete for funds globally. Globalization of capital flows is no doubt manifested in multiple dimensions. For our immediate purposes, however, one salient point matters

[13] World Bank Report, 2007.

most: the prospects of future returns and capital risks associated with a capital position in BLPC, as gauged by the holders (investors) of capital, are *benchmarked* with respect to the expected returns obtainable from alterative investment opportunities of comparable risks elsewhere. The universe of opportunities is large, and one can expect that investment opportunities are fairly gauged in terms of risks and potential returns.

SOVEREIGNTY RISKS

Sovereignty risk refers to the risk differences among comparable types of financial assets, including government and corporate bonds and common stocks, according to the country of origin of the asset. Sovereignty risks are evidenced by observed risk premia among financial assets across countries, and are most relevant for developing nations and regions where risk differences with respect to developed economies reflect the inherent level of uncertainty and risks of emerging economies. Emerging markets are typically less developed and complete, are notably more vulnerable to currency risks, and are much less capable of diversifying exports and the effects of widely varying world commodity prices. Similarly, the financial assets sourced in emerging markets are less liquid and may not reflect full information reporting standards. Finally, investors in emerging markets are likely to have less complete information and knowledge regarding the full extent of risks, including political and more general institutional intricacies. Moreover, some regions experience periodic and chronic levels of civil unrest and warfare. Observed market yields suggest, then, that so-called sovereignty risks are real. The relevant question is how best to gauge the risk premia associated with the financial assets of emerging economies, where the focus is common equity.

Under conditions in which the underlying assets are traded within sufficiently competitive and liquid markets, the well known tools of capital valuation, including CAPM and Discounted Cash Flow, provide a basis to develop estimates of the cost of capital. In the case of emerging markets, however, financial markets are often incompletely developed. The market size (capitalization) of debt obligations and common stocks traded on the exchanges of emerging markets are typically of small scale; the number of listings are often few, and trading activity is thin and often intermittent. In short, the relevant valuation tools, as developed by and actively

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exploited within the financial markets of the developed economies of the West and the Far East, are not easily applied. Consequently, several sensible though *ad hoc* approaches for determination of sovereignty risks have been and are applied in lieu of formal valuation methods, at least as applied to the within-nation exchange experience. These methods include:

Nation-Specific Equity Market Risk Premia: Using a worldwide equity market index such as Morgan Stanley Capital Index (MSCI) and estimated risk premia, develop CAPM or APT multifactor[14] estimates of the cost of capital specific to the equity markets of the nation of interest.

Observed Risk Premia of Government Debt: This second approach reviews historical bond yields and short-term interest rate differentials of the outstanding debt obligations of sovereign nations. Under this approach, bond yield differences stated in real terms, constitute risk premia, and represent common risk differences that are then applied, in common, to the financial assets sourced to the public and private entities of the nation of interest.

Credit Scores Differences: Entities that provide financial services such as *Institutional Investor* periodically conduct surveys of traders involved in the assessment of capital risks. Through these surveys, a consensus risk assessment and associated credit rating is developed. In turn, the composite credit rating is used as a basis to explain real debt costs and historical market returns. The resulting model provides a basis to estimate risk premia, given the observed credit rating scores obtained from the surveys. The credit scores of global credit rating agencies can be correlated with observed real interest rates.

Relative Risks of Equity Market Returns: Indexes of historical market returns for exchanges of emerging nations are formulated. The statistical variance of the index (market returns) serves as the appropriate risk metric. The variance (or standard deviation) of market returns of the emerging market exchanges is then normalized with respect to the index of a major equity market exchange, such as the S&P500.

[14] APT refers to *Arbitrage Pricing Theory*. Originally formulated by Stephen Ross in 1980, APT and multi-factor models are often viewed as extensions of the CAPM framework, within which CAPM Beta constitutes a one-factor approach. Multi-factor models such as the Fama-French 3-factor model have been shown to better explain historical market returns than the now classic CAPM framework.

The result is a relative value of the average equity market for various emerging markets, where the values vary around (are somewhat above) unity. The final step is to multiply the observed equity risk premia for the major exchange by the calculated values of relative statistical variances for the emerging markets. These adjusted equity premia are then coupled with low-risk sovereign debt yields for the markets of interest.

In short, there are several plausible ways to potentially address the question of the existence and magnitude of sovereignty risks. While all four approaches are seemingly viable, some methods are likely to provide more reliable estimates of true underlying country risks than others.[15]

METHODOLOGY: ESTIMATION OF THE COST OF EQUITY

It is useful to reiterate three essential points that we elaborated upon above. First, the cost of equity of the firm—and of investors in the firm—is a function of perceptions of risk, the demand for and supply of capital, and expectations of inflation. Second, the cost of common equity of the firm is equal to the opportunity cost of capital incurred by common shareholders of the firm contemporaneously, though the experience of long-term history guides the assessment of opportunity costs. Third, the cost of equity of the firm is equal to the expected market rate of return on alternative investments of comparable risks available to shareholders—*i.e.,* the opportunity cost of capital—within a contemporary timeframe.

For two fundamental reasons, the determination of the opportunity cost rate for equity capital is both challenging and somewhat removed from the analytical procedures used to determine the cost of debt. In the case of debt, both the market price and future expected cash flow returns associated with debt securities are generally observable, by inspection. Thus, the net expected yield to maturity, which reflects the opportunity cost of capital to holders of debt, can be determined directly. This *is* the market rate of return, *ex ante*. For purposes of determining the overall utility rate of return, however, the cost rate of long-term debt is that which is set at the time of debt issuance in primary financial markets.

[15] In particular, the nation-specific equity market risk premia approach appears to provide counterintuitive and inconsistent results for some emerging markets and regions.

In contrast, expectations of investors about the prospective cash flows and market returns on common equity cannot be observed directly, and must be inferred using estimation procedures. In addition, the allowed equity rate of return is typically set according to the current and expected cost of capital, though much of the equity investment was committed in many years past. That is, the cost of equity may change over time significantly—and rapidly—as market conditions change even though the original equity contribution to total invested capital, measured as book value, typically remains unchanged.

In summary, the cost of common equity can only be discerned through the proper and careful application of well-established methods that provide the cornerstone for modern finance theory. While the methods employed herein are well-established, the procedures to determine the cost of equity capital require estimation of key parameters.

The return on equity recommendation on equity for the Company is based on the equity cost of capital, as determined through the application of four estimation methods. The methods include variants of the constant growth *Discounted Cash Flow* model ("DCF"), and the *Capital Asset Pricing Model* ("CAPM"). These classical approaches are commonly recognized within modern finance theory and are readily utilized for purposes of capital valuation. These two formal models of the cost of capital are augmented by an assessment of *Realized Market Returns* for utility and non-utility companies of comparable risks, and estimates of cost of capital, as inferred through the *Risk-Premium* methodology. While other technical methods are available—notably, multi-factor models—the four approaches utilized in the Cost of Capital Study are widely accepted and used for purposes of capital valuation. Each of the methods is discussed below.

Discounted Cash Flow. The constant growth Discounted Cash Flow model was originally developed by Myron Gordon in 1957, and was advanced actively during the early 1960s. In its classical (one-stage) form, the derived DCF model defines the cost of capital as the sum of the adjusted dividend yield, and expectations of future growth in cash flows to investors including dividends and future appreciation in share prices. The classical DCF model is as follows:

$$k_{e,j} = D_{0,j}(1+E(g_j))/P_{0,j} + E(g_j)$$

with,

$k_{e,j}$ = cost of equity capital, asset j

$D_{0,j}$ = current dividends per common share, asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share, asset j

The one-stage form of the DCF approach is an elegant and intuitively tractable model with two terms, a mathematical result derived from the constant growth present value model. A cursory review of historical returns on equities suggests that, to a substantial extent, differences in the observed internal returns to capital, as well as expectations of future returns as expressed by security analysts, contribute to realized market appreciation as well as total returns to capital. It is plausible that the *expected path* of future returns harbored by investors may assume a pattern of non-constant growth. This means that, at least under some market conditions, the constant growth form of discounted cash flow may not represent investor expectations of growth with sufficient accuracy. Arguably, other forms of DCF may serve as better approximations of investor expectations.

A plausible approach to better model expectations of varying growth might be with stochastic models, where the path of returns and growth is a function of time, with a random component. However, stochastic models introduce considerable complexity. As a first-order approximation to stochastic processes, multiple-step constant growth models known as multi-stage DCF can serve nicely. Essentially, multi-stage DCF is a variation of present value theory which postulates that future returns assume a pattern of several growth steps or stages. While any number of stages of constant growth is possible, two or three stages are typically applied. In stylized fashion, the Three-Stage DCF model is shown below:

$$P_{0,j} = (1+g_j)/(k_{e,j}-g_j)\{D_{0,j}(1 - F^5_j) + D_{5,j}(F^5_j - F^{10}_j) + D_{10,j}(F^{10}_j)\}$$

with,

$k_{e,j}$ = cost of equity capital, asset j

$D_{t,j}$ = current and future dividends per common share, asset j

$E(g_j)$ = expected growth in future cash flow returns to investors in asset j

$P_{0,j}$ = current price per common share, asset j

F_j = $(1+E(g_j))/(1+k_{e,j})$

As shown in the above formulation for the Three-Stage DCF, discounted prospective cash flows are represented by three terms that incorporate the factor "F," each of which is differentiated by expected growth (*E(g)*). In the Three-Stage approach—should we say multi-stage approach—investor expectations of future growth are differentiated among time frames. Unlike the single-stage DCF approach, the estimated cost of equity capital solution to the multi-stage model (the discount rate *k*) is obtained through a mathematical search procedure that iteratively searches for the discount rate that balances the left- and right-hand-sides of the equation. Appendix I provides a step-by-step derivation of the classical and multi-stage discounted cash flow models shown above.

Capital Asset Pricing Model. The CAPM was developed by William Sharpe (1961) and John Lintner (1964). CAPM was derived from mean-variation analysis and, in particular, portfolio selection developed by H. Markowitz (1952). The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk-free returns and an *adjusted risk-based return.* Surrogates for risk-free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. Some applications of CAPM, long-term debt. As a general rule, the cost rates for and market returns of government debt obligations are accepted as "riskless assets" and thus serve as appropriate proxies for risk free yields.

The adjusted risk-based return is based upon three factors: 1) the covariation of the returns to the asset and that of markets for risky assets, 2) the statistical variance of returns of the market for risky assets, and 3) the *difference* between expected overall returns on risky assets, and risk-free returns. The third parameter is referred to as the excess return, and is equal to the difference between the overall returns to risky assets for the market as a whole, and the risk-free return rate. The CAPM is shown below:

$$k_{e,j} = r_f + B_{jm}*(r_m - r_f) \qquad \textit{with, } B_{jm} = \sigma_{jm}/\sigma_m^2$$

with,

$k_{e,j}$ = cost of equity capital for risky asset *j*, stated in percentage terms

r_f = risk-free rate of return

B_{jm} = ratio of the covariation between risky asset *j* and the market as a whole, σ_{jm}, and the variance of market returns, σ_m^2

r_m = expected rate of return on equity markets, as a whole

Appendix II derives the Capital Asset Pricing Model, as shown above. The derivation is developed by David Luenberger.[16] The efficient market hypothesis plays an essential role in the determination of the cost of capital. Specifically, the working assumption, which is largely though not completely borne out by empirical analysis, is that capital markets are fairly efficient. This means that the supply and demand for risky financial assets, as reflected in bid and asked prices to buy and sell shares, result in financial assets being traded at price levels where *rates of return above the cost of capital cannot be systematically realized.* Above-normal returns—returns above the cost of capital—are realized only randomly. Essentially, the opportunities to systematically realize returns above the underlying cost of capital are exhausted by the competitive market process.

Estimating the cost of capital, though not trivial, can be fairly straightforward, and the four approaches employed in the immediate Study—DCF, CAPM, Historical Market Returns, and Risk Premium—provide a useful analytical framework from which the cost of equity can be inferred. The risks to investors in various sectors of the energy services industry cannot ever be known directly; risks and hence the implied cost of capital can only be inferred. Specifically, the determination of useful estimates of the cost of common equity capital within each method requires a discerning application of theory through careful analysis, such as that presented herein. In particular, the determination of the cost of equity capital faces two overarching challenges, as follows:

(i) The selected and applied methods herein are inherently forward looking, where future expectations are gauged from history. Hence, the results are highly dependent upon useful estimates of investor expectations about future market performance. However, future expectations are drawn from history and underlying relationships among historical information data. Arguably, all that we know—indeed, all knowledge—is based on observed facts (historical data) and perceptions of relationships among data; and,

(ii) Key underlying assumptions include efficient markets and rational behavior of investors such that all opportunities for above- and below-normal returns to capital are exhausted on an expected value basis. In short, capital

[16] David Luenberger, *Investment Science*, 1997.

markets value financial assets at the implied opportunity costs of capital, given investor perceptions of risk.

It is useful to mention that the notion of *risky assets* can apply to any real or financial asset wherein the prospective returns from holding the asset are uncertain. Risky assets include commodity contracts, financial property rights, financial derivatives, and real assets such as power delivery and generation facilities of electric utilities. Risk assessment and option theory, moreover, can be applied to the analysis of unbundled services, such as electricity transmission development plans. Within the context of this discussion, however, risky assets refers to financial obligations of firms—common stock—and asset values refers to prices of common stock as observed on major stock exchanges.

Measurements of *Realized Market Returns* and risk metrics are increasingly used as a basis to assess plausible returns in the future. As discussed, efficient markets suggest that *all* financial assets are priced at levels such that the *expected* future returns of individual assets are equivalent to the underlying opportunity cost. Thus, if historical returns guide expectations of future returns, historical returns provide a useful benchmark and, within reasonable bounds, reflect the opportunity cost of capital. In this respect, the *Realized Market Returns* methodology can be viewed as a market-based approach of Comparable Earnings, and thus fully satisfies the *Bluefield* and *Hope* criteria. More specifically, realized market return for a period is defined as:

$$\boldsymbol{R_{j,\,t-t\text{-}1} = (P_{j,\,t} + D_{j,\,t-t\text{-}1} - P_{j,\,t\text{-}1})/P_{j,\,t\text{-}1}}$$

with,

$R_{j,\,t-t\text{-}1}$ = market return realized within the interval $t - t\text{-}1$, for financial asset j

$D_{j,\,t-t\text{-}1}$ = dividends paid during the interval $t - t\text{-}1$, for financial asset j

$P_{j,\,t,\,t\text{-}1}$ = market value of financial asset j, at t and $t\text{-}1$

The key to successfully applying this third approach is identification and measurement of historical returns in a manner that reasonably reflects expectations of investors about the future outlook.

The *Risk Premium* methodology is based on ordering of types of financial assets according to yields—and thus risks—as observed historically. This ordering according to risks is a natural and inevitable result of competitive financial markets.

Essentially, because risk is costly, higher costs must be offset by higher returns. While the Risk Premium appraoch is not based upon a conceptual model and derived form, the application utilizes CAPM. The analysis of the risk premia among classes of risky assets provides a means to infer the underlying opportunity cost of capital. The underlying concept of the risk premium approach is that *differences* in perceptions of risks among financial assets such as equities and debt are revealed in differences between the historical market returns. The historical differences between equity and debt returns—*i.e.*, risk premia—can thus serve as estimates of required compensation for risk assumed by investors over future timeframes. The approach begins with expected inflation, and then takes account of the expected cost of short- and intermediate-term debt, equity risk premia, risk differences between equity markets as a whole and utilities as measured by CAPM beta, and size-related risk premia where appropriate. While risk premium models can assume various forms, the immediate application of the Risk Premium approach is codified as follows:

$$k_{e,j} = r^{st}{}_f + rp_{int-st} + rp_{m-nit} + rp^{CAPM}{}_{y-m} + rp^{s}{}_j$$

with,

$k_{e,j}$ = cost of equity capital for risky asset j, stated in percentage terms

$r^{st}{}_f$ = risk-free rate of return, for a short-term asset

rp_{int-st} = risk premium for intermediate-term asset *int* with respect to a short-term asset

rp_{m-int} = risk premium for equity market m with respect to an intermediate-term asset

$rp^{CAPM}{}_{y-m}$ = risk premium for industry y with respect to equity market m, where y refers to the relevant industry sample

$rp^{s}{}_j$ = size-based risk premium for risky asset j[17]

Application of the Risk Premium approach contains two potential pitfalls, as follows:

- the opportunity cost of common equity capital, stated in nominal terms, is sensitive to the demand for and supply of capital;
- risk premia among debt and equity instruments are also quite sensitive to expected inflation. Thus, Risk Premium analysis must account for expected inflation in the future. That is, the underlying rate of inflation and conditions

[17] Size-related risk premia are, as a general rule, relevant within the context of the Capital Asset Pricing Model. Specifically, the CAPM-based estimates of market returns appear to systematically understate the cost of equity capital for small-sized stocks. Size-related risk premia may not be relevant or appropriate in other model contexts.

of the historical period over which risk premia are estimated must match those of the expected conditions of the relevant period over which the common equity recommendation is being applied, and over which retail electricity prices are being set.

PART II: ANALYSIS OF COST OF CAPITAL

BUSINESS and FINANCIAL RISKS: BARBADOS LIGHT & POWER

Setting forth recommendations regarding the appropriate rate of return is not a mechanical model-driven result obtained in isolation. An understanding of business context to gauge capital risks is essential. Risk assessment should take account of the generic risks attending entities involved in energy markets and electricity service providers, as well as idiosyncratic risks associated with specific business context. Accordingly, analysis of the cost of capital, for purposes of setting the rate of return, should be fully informed and sensitive to the facts defining the relevant generic risks and the idiosyncratic risk profile of BLPC.

Generic business risks attending the cost of capital for electricity service providers are strongly interdependent and will be briefly mentioned. In the contemporary environment, electric utilities face rapidly rising costs at a time of general tightening of the supply-demand balance, ongoing advances in electricity demand, and rapidly heightened requirements for environmental compliance. Increased upward cost pressures, in turn, precipitate increased resistance to price increases and scrutiny by stakeholder groups of the prudency of utility resource decisions and the reasonableness of cost levels. Rising cost pressures are a particular concern for the Company in view of the surge in prices for primary fuels, driven in part by the sharp decline in the U.S. currency with respect to other major international currencies.

All too often, cost pressures from the perspective of investors and utility managers arise as a result of issues of timeliness of rate relief, and less than full recognition by regulators of legitimate costs. The end result is a shortfall of revenue with respect to cost levels, manifest as increased variation in operating income, lower interest coverage on debt, and earnings that may not cover investors' cost of capital.

BLPC is a comparatively small, full service integrated electric utility. On the basis of size alone, BLPC carries an element of risk additional to that of larger utilities delivering the same full range of services. As discussed below at considerable length, empirical evidence suggests that, within the context of diversifiable financial risks defined by the CAPM framework, the cost of capital rises with small size. Essentially, all other factors constant, small capitalization equities have higher non-diversifiable risks than larger companies. Additionally, investors may harbor higher risks because of uncertainty of market valuation attributable to limited information.

As an island power system, the Company and its investors are exposed to special dimensions of risks relative to utilities in larger economies. Island electric power systems implicitly harbor higher operating risks. Specifically, BLPC cannot immediately draw upon neighboring power systems in the case of a major equipment failure for either high voltage transmission or for generation reserves. Accordingly, the Company must carry fairly high levels of reserves for generation services. Furthermore, small-sized electric systems enmeshed within larger continental power systems and markets can diversify generation operational risks and costs by carrying a comparatively large number of small-scale ownership shares in multiple facilities. In comparison, BLPC's physical stock of generation resources is relatively indivisible. Capital indivisibility of generation adds to operational risks in obvious ways. In addition, however, capital indivisibility implies that generation additions, which come about frequently in view of the fairly high rates of growth of Barbados' electricity demand, are brought to commercial operation in rather lumpy increments.

In the case of power delivery, the Company is not embedded in highly integrated meshed power systems of the major continents; other factors constant, the implicit level of reserves within power delivery for BLPC must be at higher levels with respect to its counterparts in Continental power systems. Moreover, BLPC is unilaterally exposed to the damaging impacts of large storm systems that, from time to time, can threaten Barbados and the Company's power delivery systems. While the Company is partially insured for these events of major magnitude, the possibility of such events precipitates technical and institutional uncertainty that translates into risk regarding the continuity of revenue and the future returns to capital. Similarly, fuel supplies for BLPC cannot be readily diversified across fuel types, multiple sources, and transportation modes, as they can for continental systems.

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In summary, then, one must conclude that, from the perspective of investors, the Company is not readily able to diversify capital risks to the same degree as other utilities.

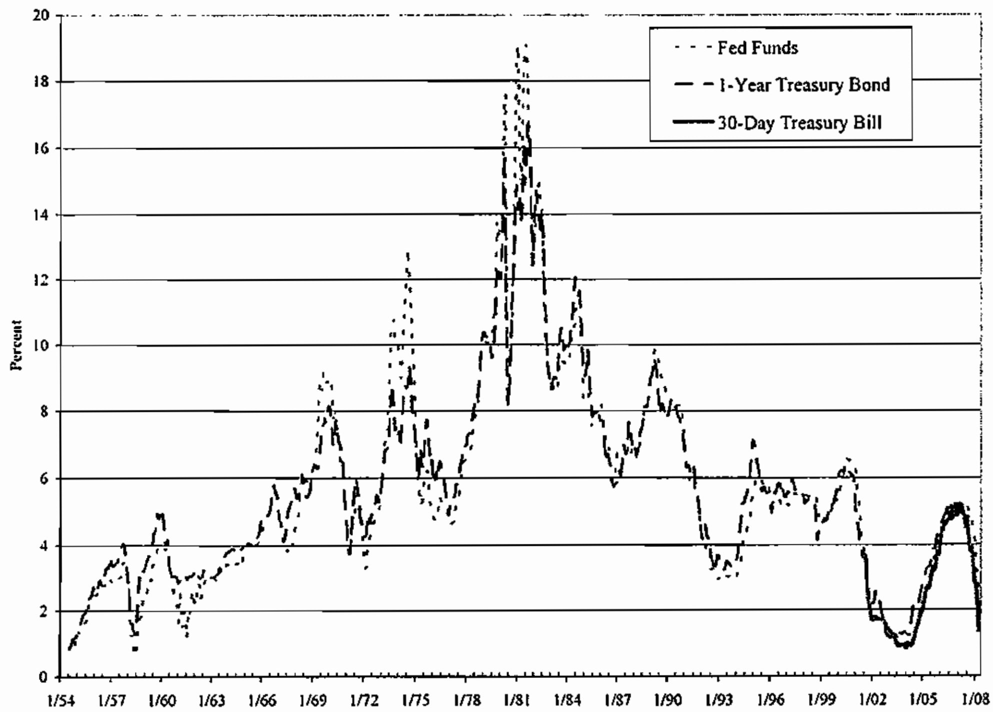
INTEREST RATES TRENDS

As mentioned earlier, long-term interest rates follow current and expected inflation to a substantial extent, whereas short-term interest rates are sensitive to both inflation and monetary policy geared to preserving real economic growth and stability. Indeed, a major international development during the mid-1990s has been much more disciplined money supply that has obtained a corresponding decline in worldwide inflation. Because less inflation is needed to compensate for the loss in purchasing power resulting from the escalation in money supply, interest rates have declined significantly.

In any case, it is useful to review the interest rate experience over both the long-term history and contemporary timeframes. Shown below are selected short- and long-term interest rates for the periods 1954 forward and 2000-2007. Short-term rates are represented by U.S. Fed Funds interest rates, and the yields for 30-Day treasury Bills and 1-Year Treasury Bills; and long-term rates are represented by the yields for AAA-rated corporate bonds, BAA-rated corporate bonds, 5-year U.S. Treasury Bonds, and 10-year Treasury Bonds.[18]

[18] There is a wide range of debt mediums—and thus interest rates—across U.S. financial markets, including prime rate commercial bank loans, rated and non-rated commercial paper, constant maturity U.S. Treasury bills and bonds, Fed Funds and London Interbank Offer Rate loans of various durations, corporate bonds including debenture and mortgage debt, municipal bonds, home mortgages including variable and fixed-rate loan vehicles, and a range of securitized debt referred to a structured finance.

SHORT-TERM U.S. INTEREST RATES, 1954 - 2007



The remarkably low short-term interest rates at the beginning of the period, the mid-1950s, were a direct result of very low inflation. As can be observed, short-term interest rates prior to the early 1970s resided below 6% except for the notable but short-lived excursion of 1969-70. In the 1970s and continuing through the recession of 1990-91, the U.S. experienced substantially higher short-term rates, typically in the range of 8-10%, with the exception of the 1979-1983 timeframe, where short-term interest rates ran briefly above 16% during an environment of highly restrictive monetary policy geared to reduce the high inflation of the period. Not surprisingly, this era of U.S. monetary history was also an era of much higher inflation, particularly during the very late 1970s-1985, with gradual declines thereafter. From 1991 forward, however, short-term interest rates receded back to sub-6% levels.

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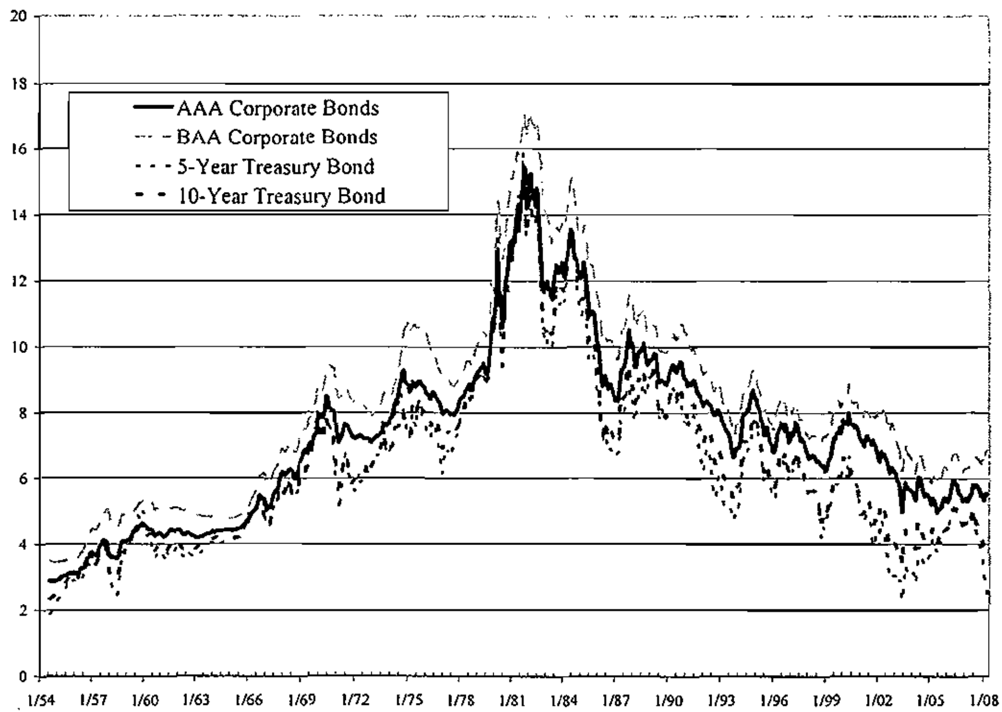
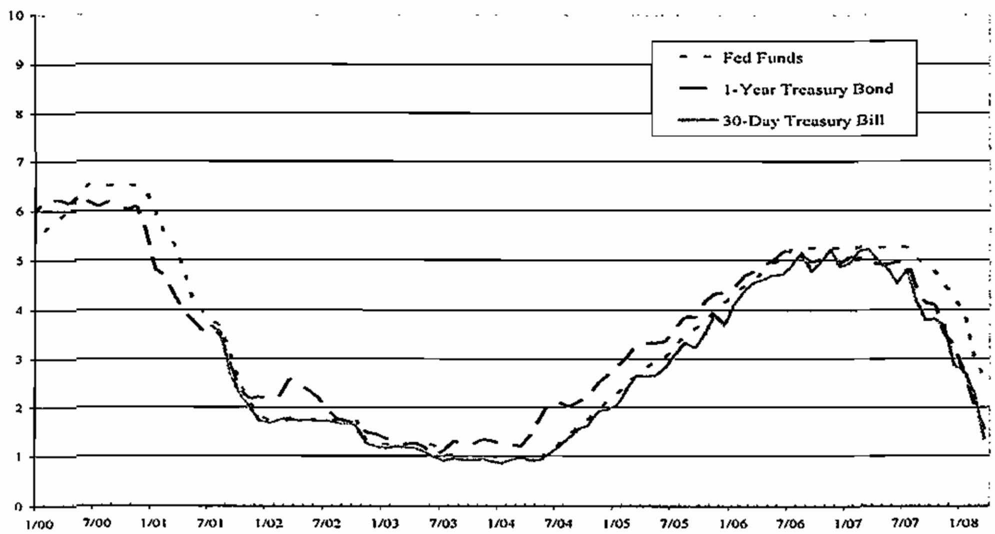
LONG-TERM U.S. INTEREST RATES, 1954 - 2007



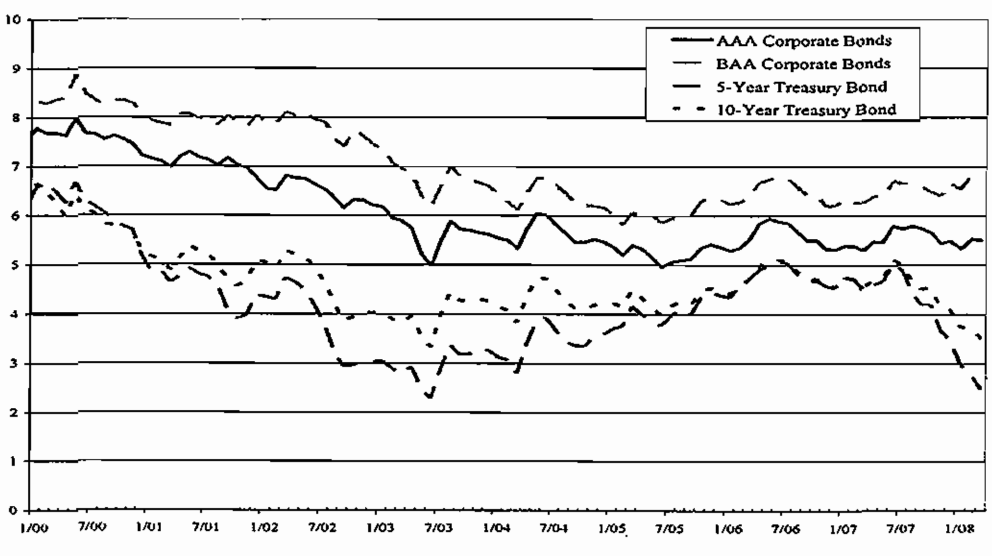
The pattern of long-term interest rates largely parallels that of short-term rates, as discussed above and shown in the previous graph. Not surprisingly, the interest rates on corporate debt consistently reside above those of U.S. Treasury debt. Most interesting, however, is the spread between corporate and treasury debt. The interest rate differences between corporate and treasury debt have increased significantly during the post-1991 period when compared to the period of comparable rates of inflation, 1954-1969.

SHORT-TERM U.S. INTEREST RATES, 2000 - 2007



Turning to the more contemporary period, two features are noteworthy. First, short-term interest rates, driven by expansionary monetary policy, dropped to unprecedented low rates of less than 2%, and remained at that level for the period 2002-2004. Second, beginning in late 2007, short-term rates declined precipitously, again driven by an accommodative monetary policy quickly implemented in response to the sudden decline the level of economic activity.

LONG-TERM U.S. INTEREST RATES, 2000 - 2007



The essential feature of long-term interest rates currently is the increase in the interest rate spread between corporate and U.S. treasury securities, particular for BAA bonds.

Whereas long-term treasury yields, following short-term interest rates, have declined by 1.5-2.5 percentage points since July 2007, corporate interest rates show little movement. Moreover, corporate BAA debt yields have risen, despite the general decline in interest rates, as a result of higher perceived default risks. No doubt, the relevant development occurring just recently within the U.S. and, to a lesser extent in international debt markets, is the sharply higher default risks associated with the structured financial vehicles (asset-based financing) of various types.

In the case of Canada, growth in real economic activity and productivity has assumed a general upward path since about 1991, commensurate with a gradual move favoring economic liberalization in the form of privatization and mitigation of regulatory burdens. In particular, the Bank of Canada has implemented more disciplined monetary policy that, in general, have resulted in reduced levels of inflation and corresponding decreases in short- and long-term interest rates, as revealed in the following table.[19]

CANADIAN TREASURY YIELDS (%)

Year	3-Month Bills	2-Year Bonds	10-Year Bonds
1982	13.7	12.9	13.7
1990	12.8	11.4	10.8
1991	8.7	8.8	9.4
1995	6.9	7.2	8.1
2000	5.5	5.9	5.9
2005	2.7	3.2	4.1

OVERALL EQUITY MARKET RETURNS AND RISK PREMIA

Market rates of return and equity risk premia are positively related to productivity and general economic performance. The economies of North America are fairly well positioned to realize and sustain substantial if not high rates of growth in productivity and real output, along with near full employment and modest inflation over the

[19] The historical interest rates shown for 2000 and 2005 confirm the risk-free Canadian cost rate of 4.64% (monthly, 2002-2006) utilized in the CAPM analysis for the Canadian samples 1 and 2, as discussed below.

foreseeable long-term future.[20] Investors generally share this consensus view and, accordingly, the analysis herein draws upon realized overall market rates of return and interest rates as representative surrogates for the near-term future, and over which retail prices are likely to be in place. The average percentage return for U.S. equity markets overall, as gauged by the S&P 500 index, was 12.8% from 1970 through 2006,[21] which is the period of representative levels productivity growth in view of future potential. The 12.8% overall market return level over 1970-2006 is used as the expected level of future returns to equity markets within the CAPM analysis for U.S. markets, with commensurate levels of market risk premia of 8.07%. Moreover, this longer-term experience is consistent with contemporary productivity levels and realized returns to equity markets. For the U.S. economy, the average rate of observed productivity growth for the period 1970 forward resides well within the range identified above, and covers a very slow-growth period—the late 1970s to early 1980s—and the high productivity growth of 1995 through 2003. Productivity growth appears in have receded somewhat in recent years from the exceptional levels obtained during '95-'03 timeframe. Given the relationship between market returns and productivity and other conducive factors, and because overall productivity growth over this timeframe is a reasonably close match to the expected range of productivity in the future (see Martin Baily, Dale Jorgenson) investors have reason to expect annual level of overall market returns to approach 11.5 to 13.0%. For U.S. equity markets, realized market returns for the period 1970 – 2006 comport well with realized market returns over extended periods, as shown below, with little change in sight.

[20] Generally speaking, Canadian productivity will likely remain slightly less than that of the U.S.

[21] Contemporary high rates of productivity growth were obtained through the widespread adoption of information technologies including computers, common communication and software platforms that facilitated efficient information transfer.

Total Market Returns through 2006		
Number of Years	Initial Year	Realized Historical Annual Return (%)
81	1926	12.30
70	1937	12.30
60	1947	13.20
50	1957	11.90
40	1967	12.30
30	1977	13.60
20	1987	13.00
10	1997	12.00
Average, '67-'07		12.7
Average, '77-'07		12.9

Similar reasoning—namely, the causal link of productivity growth to overall equity market returns and risk premia—leads to a Canadian risk premium of 6.63% over the relevant timeframe, 1991-2006. As alluded to in the above discussion, these levels of risk premia are consistent with the level of contemporary productivity growth and cost of capital for Canada[22], particularly when coupled to comparatively low levels of inflation and disciplined monetary policy—key contributing factors to realized equity market returns.

However, overall economic performance and long-term growth can be attenuated by events of a transitory nature and by various long-term processes that can contribute to capital risks such as the costs to maintain environmental quality, or world-wide cultural friction. An immediate example is the decline in credit market liquidity observed in recent weeks. Finally, it is important to mention the impact of government fiscal policy and global demand for capital on interest rates. As mentioned, the cost of capital is a function of the demand for and supply of funds, and we expect U.S. and world demand for capital to remain at high levels, thus placing steady upward pressure on interest rates. As a result, long-term interest rates are likely to remain at or near current levels, which are close to historical experience despite recent declines in short-term interest rates.

[22] This 16-year period experienced a market rate of return of 11.26%, which closely approximates the observed realized returns of 11.34% for the 2002-2006.

SELECTING COMPARABLE RISK COMPANIES: COST OF EQUITY

As defined by the "Bluefield" and "Hope" decisions of the U.S. Supreme Court, a public utility (to paraphrase), is entitled to a rate of return on shareholder capital committed for the convenience and necessity of the public equivalent to that realized by companies in other businesses of comparable risk. Thus, the task at hand is comparability: to identify the relevant markets, and to then select companies of comparable business, regulatory, and financial risks to those of BLPC. Estimates of the cost of equity are obtained by applying the cost of equity methods to the sample companies, with trading experience on the major exchanges of the North American Continent.

For several reasons, the study cannot readily draw upon, at a technical level, the capital market experience of utilities and companies in the Caribbean for purposes of capital valuation. The Caribbean exchange-traded capital markets, which effectively consist of the Exchanges for Barbados and for Trinidad and Tobago, have comparatively low levels of liquidity with shallow trading activity from which to estimate prospective market returns and risk premia. Second, the exchange listings contain few market-traded infrastructure entities from which to assemble a comparable risk utility sample – which is necessary in order to ensure that the study results conform to the Fair Rate of Return principles defined above. Third, the common stock trading experience of the Caribbean Exchanges is unusually thin, which would impose special analytical procedures on the study.

Accordingly, the study approach is to estimate the cost of equity for samples of utilities with equities that trade on the major exchanges of North America (U.S. and Canada), and to adjust the cost estimates for utilities of the Continent for the risk premium (cost rate difference) between Barbados and the Continent. An empirical estimate of the risk premium, which can be referred to as sovereignty risk, is detailed below in the section entitled *Cost of Equity Capital and Sovereignty Risk.* However, the sovereignty risk premium can also be gauged by comparing the expected real risk-free interest rate (rate of return) on the debt of the Central Banks of Barbados and the U.S., as shown in the following table.

RISK PREMIUM, BARBADOS (BB) WITH RESPECT TO U.S.

2005 Issues, Central Bank of Barbados		
Bond Issue Date	**Bond Maturity Date**	**Coupon Interest Rate (%)**
14-Feb	31-Mar-11	5.00
27-Jun	30-Jun-25	7.25
1-Sep	31-Mar-07	5.25
26-Sep	30-Sep-17	7.00
28-Nov	30-Sep-14	7.25
28-Dec	31-Dec-25	7.25

Risk Premium, Barbados with Respect to U.S.	
Interest Rates of BB Issues Maturing Beyond 2011	7.19%
2005 Inflation Rate, Barbados	3.86%
Implied Real Risk-Free Interest Rate, Barbados	3.32%
Interest Rate, U.S. 20-Year Bonds	4.65%
Expected Inflation, U.S.*	2.68%
Real Risk-Free Interest Rate (TIPS), U.S.	1.97%
Risk Premium, BB with respect to U.S.	1.36%

2008 Secondary Market Yields, Central Bank of Barbados		
Bond Issue Date	**Bond Maturity Date**	**Expected Yield to Maturity (%)**
Jun, '94 - Oct, '03	Oct, '18 - Oct, '20	6.75
Oct, '02 - Dec, '05	Oct, '22 - Mar, '30	7.46

Risk Premium, Barbados with Respect to U.S.	
Interest Rates of BB Issues Maturing Beyond 2017	7.10%
2007 Inflation, Proxy for Prospective Rate, Barbados	3.90%
Implied Real Risk-Free Interest Rate, Barbados	3.20%
Interest Rate, U.S. 20-Year Bonds	4.54%
Expected Inflation, U.S.*	2.54%
Real Risk-Free Interest Rate (TIPS), U.S.	2.00%
Risk Premium, BB with respect to U.S.	1.21%

* Difference Between U.S. 20-Year Constant Maturities and TIPS (Treasury Inflation Protected Securities) Interest Rates

The top half of the table provides an estimate of the risk premium for Barbados based on primary market issues by the Central Bank of Barbados in 2005, while the bottom half uses yields on secondary market values to provide an update for conditions in 2008. (There are insufficient primary issues in 2008 for an exact replication of the top half of the table.) The risk premium for Barbados appears to be reasonably stable, at 1.36% in 2005 and 1.21% in 2008.

Nonetheless, the study draws on the universe of equities of the U.S. and Canadian capital markets as a starting point from which to select comparable risk utilities and companies. Once selected, we then estimate the cost of common equity for the sample(s) of comparable companies. A key distinction regarding comparability is market size. As recent empirical evidence convincingly demonstrates that, predominantly because of information inefficiencies and uncertainty, the cost of capital rises as firm size declines all other factors held constant.

For the samples of U.S. companies, we have drawn heavily—though not exclusively—from a set of data and information sources including Value Line data banks, Ibbotson Associates (Morningstar), and the web-based services of Yahoo Finance, UBS Financial Services, and Zacks Financial Services. With few exceptions, the equity shares of the sample are traded on the New York Stock Exchange and the NASDAQ exchange originating from the over-the-counter trading procedures put in place by the National Association of Securities Dealers in years past. For these equity listings, a wide range of financial data, business descriptions and classifications, historical price experience, and various diagnostic statistics of interest are reported. The sample of Canadian companies is drawn from utility companies listed on the Toronto Stock Exchange, referred to as TSX.[23]

From the U.S. market portfolio we proceed to develop two utility company samples and a comparable risk non-utility sample. The first sample, Mid-Sized Electric

[23] The equity listings of NYSE, NASDAQ, and TSX very clearly do not constitute the full set of investment possibilities. Indeed, some 75 stock exchanges currently exist worldwide. Arguably, some combination of the Morgan Stanley Capital Markets (MSCI) plus exchange indexes of the North American equity markets is a more complete representation, when assessing the performance of equity markets at a summary level, which is necessary in the case of CAPM, Risk Premium, and also Arbitrage Pricing Theory-based methods. However, the North American equity markets, as represented by the many listings on these three exchanges, are highly liquid. Accordingly, movements and performance of the indexes for the North American markets closely parallel movements of other world indexes, though differences are observed as a result of currency exchange rate movements, unanticipated random social and physical events within regions, and significant changes in expectations of economic performance. In addition, the North American markets, unlike worldwide exchanges, carry equity listings for numerous utility companies.

Utilities (U.S. sample 1) is limited to retail electricity service providers that have modest yet significant levels of market participation and, with the exception of size-related capital risks, are of comparable risk to that of BLPC. The second U.S. utility sample is referred to as the Moderate-Sized U.S. Gas Distribution Utilities (U.S. sample 2), and is composed of retail natural gas service providers. Our studies demonstrate that, as a practical matter, the level of capital risks and thus the opportunity cost of capital for the two samples, electric utilities and natural gas utilities, is comparable. For purposes of determining the equity rate of return requirements of BLPC, the study also draws a third U.S. sample, referred to as Comparable Risk Non-Utility Companies (U.S. sample 3). Our methods tend to demonstrate that, particularly within contemporary capital markets with high levels of international capital flows, comparable risk is the predominant selection criterion. Line of business appears to have only a modest level of relevance to cost of capital, once the comparable risk criteria are satisfied. Thus, samples can be drawn from a broad range of business fields, generally speaking.

The determination of the first sample, the mid-sized electric utilities, involves two steps. The first step is to conduct an initial screen according to the predefined selection criteria. As mentioned, these criteria are as follows:

- *Liquidity*: companies that are of modest size but yet have sufficient market presence and participation to ensure sufficient market activity and transaction volume;
- *Business Line*: companies whose primary business line is retail electricity services; and,
- *Reasonably consistent financial performance.*

To determine U.S. sample 1, the study begins with 42 modest-sized entities within the U.S. electric utility and electric energy companies. For cost of capital analysis, twenty electric utility companies are selected from this initial set, where the criteria for selection are completeness and consistency of reported financial information and market data, and also electric utility services as the primary business line.[24] Some of these 20 electric companies have involvement in non-electric retail business lines including natural gas. It is virtually impossible these days to assemble a sample of companies that are exclusively in the retail electric business – sometimes referred to as a *pure play*. However, the U.S. electric utility sample is composed of entities that have a dominant share of business activity within electric power generation and delivery. This new diversity should not matter, at least on the surface, if the sample is determined on a basis of comparable risks. Indeed, endeavors to diversify risk over alternative business lines tend to reduce variation in earnings, variation in internal cash flow, and variation in market returns, thus reducing overall investment risk and the cost of capital.

From this set of 20 companies, eleven electric utilities are selected according to comparable risk criteria including. The second selection step in determining the electric utility sample applies risk criteria. These criteria include four dimensions, or metrics:

- *Equity Participation in Total Capital*;
- *Coefficient of Variation in Earnings* per share over five and ten years;
- *CAPM Beta* which, as discussed above, is the ratio of the covariation of the market returns of a specific stock of a company and the market as a whole, and the statistical variance of the returns of the market; and,
- *Variation in Market Returns*, which is measured as the coefficient of variation of monthly market prices—essentially, an index of volatility in market value (market capitalization).

Those eleven electric utility companies with risk metrics that generally fall within one standard deviation of the average for the sample of electric utilities as first drawn or are reasonably close to the metrics for BLPC are retained in U.S. sample one (mid-sized U.S. electric utilities). It is these utility companies that, by this arguably objective approach, satisfy the criteria of comparable risks and thus the U.S. Supreme Court guidelines regarding fair rate of return contained within the Bluefield

[24] The increased openness of U.S. electricity markets in recent years, including market entry as well as relaxation of financial restrictions, has resulted in an expanded range of business activity. Today, entities within the electricity services industry are, for example, involved in oil and gas exploration (MDU Resources), real estate (Pinnacle West), and significant non-electricity energy services (Integrys Energy). Arguably, Integrys Energy should be listed with the U.S. natural gas industry as it has substantial natural gas pipeline and distribution business lines in addition to two electric utility subsidiaries including Wisconsin Public Service ("WPS") and Upper Peninsula Power (UP Power).

Waterworks and Hope decisions. Tables at the end of Appendix III document the screening process.

The market capitalization of these companies, measured by common shares outstanding and market prices during 2006, ranges from $82 million for Florida Public Utilities Company to about $4.1 billion for SCANA (South Carolina Electric and Gas), stated in USD. The non-weighted average size of U.S. sample 1, the electric utilities, is about $1.8 billion USD.[25] CAPM Betas, arguably the most significant measure of capital risk, are shown in Appendix III in the adjusted form for 2006 and for 2002-2005 on average. In particular, CAPM Betas have risen over time, suggesting significantly increased capital risks associated with energy markets, including electric service providers.

The mean-variation *theory* on which the Capital Asset Pricing Model is based suggests that risk metrics other than CAPM Beta do not matter for the determination of portfolios that efficiently trade off risks and potential future return levels. However, empirical *evidence* suggests that: a) internal financial metrics such as items 1-3 above are also utilized by investors to value equities, and b) CAPM theory (as with other capital market theories) does not necessarily explain historical market returns particularly well. Thus, it appears that, to a substantial degree, information other than CAPM Beta is also relevant to investors in the valuation of equities.

Turning to the moderate-sized U.S. gas distribution utilities (U.S. sample 2) and the comparable risk non-utility companies (U.S. sample 3), the selection process proceeds in similar fashion using criteria equivalent to those employed to determine the U.S. mid-sized electric utility sample (U.S. sample 1). That is, a sample is first drawn on the bases of market liquidity and business line. The selected natural gas utilities and estimates of cost of equity for them are shown on Appendix IV. The initial set of natural gas utilities includes 27 entities that range from $55 million to 2.8 billion USD equity market capitalization in late 2007. From this initial draw,[26] 11 entities are initially selected and, through the application of the risk screen, 8 entities are

[25] Not shown but available are the compiled profiles of the sample utilities and non-utility companies, including brief reviews of the business, operating revenues, assets, and operating margins.

[26] The U.S. natural gas industry includes many regional and national distributors of liquid propane and specialty industrial gas products and services, such as Penn Octane Corporation, Suburban Propane Partners, and Continental Fuels Inc.

ultimately selected for use in the immediate cost of capital study. As with the U.S. electric utilities sample, these companies, although of comparatively modest scale by U.S. benchmarks, are all significantly larger than BLPC, which implies that BLPC has higher capital costs, holding other factors constant. In view of BLPC's business context, the Company appropriately underwrites its assets with higher equity participation than its U.S. counterparts.

The sample of comparable risk non-utility companies is drawn from U.S. non-utility economic sectors. The initial selection criteria were equity market capitalization of less than $750 million USD, equity participation in total capital of less than 0.80, CAPM Beta range of 0.40-1.00, and public domain financial data for ten years. These criteria resulted in the selection of 84 entities from well over 3,000 U.S. exchange-listed firms, where the selected firms include food markets, pipe manufacturing, financial services, health services, and a military equipment manufacturer. The application of a random selection procedure culled 27 entities[27] from the set of 84, and ultimately provided 24 entities ranging from $70 to $575 million USD equity market capitalization. The second selection screen—equity participation, CAPM beta, variation in market returns, and variation in earnings per share (internal business risk)—obtain 20 companies that together constitute the comparable risk non-utilities (U.S. sample 3). Appendix V presents the full data set for these companies.

While the U.S. sample 3 companies have similar overall risk levels to that of the U.S. electric and gas utilities, differences exist across the three samples for individual risk criteria. For example, the non-utility companies have, on average, equity participation of 70%, CAPM beta of 0.72, variation in annual market returns of 5.94%, and coefficient of variation (CV) in earnings per share of 0.37 and 0.45 for 5- and 10-years, respectively. The corresponding values for the electric utility samples are 49% equity participation, CAPM beta of 0.80, 4.00% variation in market returns, and CV in earnings per share ranging from 0.16 to 0.19. The "Selection Screen 2" Tables of Appendices V and III, respectively, present the full results.

[27] It should be mentioned that incomplete or anomalous financial data, as reported, caused some randomly selected entities to be substituted with other entities from a nearby location within the total list of 84 entities.

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The Canadian utilities, including samples 1 and 2, cover Toronto Stock Exchange-listed entities that are classified by the Exchange as utilities. The utility category covers private companies that provide a fairly broad range of infrastructure services including telecommunications, rail transportation, renewable energy, natural gas distribution, power generation, and gas transmission services, in addition to conventional integrated electricity services. Implicitly, this broad range of business and market context appears to imply, for some entities within the category, higher business and operational risks than typical U.S. electric and gas utilities. Accordingly, special caution is used in sample selection. Because of the limits in readily available financial information[28], and because the TSX-listed utility entities are comparatively few, the analysis of the Canadian utilities proceeds differently and is less comprehensive than the analysis performed for U.S. samples 1-3. Moreover, the formal selection procedures discussed above are unfortunately not directly applicable to Canada because of the small number of entities listed as utilities.

While some 22 companies are listed as utilities on TSX, half fall out of the selection process because of high-risk business context, uncertain financial performance, or because of high financial market risks, (as measured by CAPM beta). Examples of TSX-listed utilities excluded from the cost of capital study are Great Lakes Hydro (sudden, large decline in earnings), Algonquin Power Income Fund (specialized interest in renewable resources), EPCOR Power equity (holds EPCOR Power; negative earnings), Tellus Corporation (very high CAPM beta), Boralex Inc. (very high CAPM beta; power generation including hydro, wind, biomass, and natural gas cogeneration), ALTEK Power (independent power producer listed on TSX Venture), and Sierra Geothermal.

The result of the selection process is 11 Canadian utilities. Canadian sample 1 consists of conventional electric and gas utilities, whereas Canadian sample 2 consists

[28] Financial data reported by U.S. companies listed on the major U.S. equity markets including NYSE and NASDAQ are reported by the listed entities to the Securities and Exchange Commission ("SEC"). By law, the SEC imposes highly specific financial reporting standards. These data, in turn, are compiled by several financial services companies including Compustat, Value Line, Bloomberg, and others. Thus, compiled financial and equity market information can be readily obtained in non-compiled form directly from the SEC or in a compiled form from services such as these. This is not the case for Canadian companies. While compiled financial information is available through SEDAR, such data are much less complete, thus burdening valuation studies such as this with obtaining financial data in non-compiled form from the web sites of the entities of interest, and by other means.

of longstanding and consistently performing utility entities of moderate market risks in pipeline, rail transport, power generation, and telecommunication business lines. Unfortunately, the entities are comparatively large on average, and vary greatly in equity market capitalization. Specifically, the average size of Canadian sample 1 is $6.0 billion CND with a corresponding range of $15.7 to 1.7 billion, whereas the average size of Canadian sample 2 is $4.7 billion CND with a range from $65.5 million to $19.9 billion. The comparatively large size of the Canadian utilities makes the point of the necessity of incorporating size-related risk premia within the immediate cost of equity study.

In summary, the estimate of the cost of equity capital of this study involves five samples, including the three U.S. samples—the mid-sized U.S. electric utilities (U.S. sample 1), U.S. gas distribution utilities (U.S. sample 2), and comparable risk non-utility companies (U.S. sample 3); and the two samples of the Canadian utilities (CN samples 1 and 2). The estimate of the cost of capital, and thus the recommended return on common equity, is reflected as an interest rate that, by objective criteria of comparable risks, is the opportunity cost of capital incurred by the common shareholders of BLPC.

Market Liquidity is a necessary selection criterion, as stated above. The selection process results in generally smaller-sized electric and gas utilities that have sufficient liquidity. However, the selected utility companies are substantially larger than BLPC as a general rule. Because the cost of equity capital appears to increase progressively with smaller size, other factors constant, the implication is that the cost of equity capital, as estimated for the two samples, may not fully capture the inherent capital risks incurred by investors of BLPC. The topic of size-related risk premia is discussed more fully in the following section.

EMPIRICAL FINDINGS, COST OF EQUITY

This section presents the results of the analysis of the cost of equity capital appropriate for the determination of the return on equity for BLPC. The first step is to apply the four methods to estimation of cost for the comparable risk peer groups of BLPC. However, it is difficult to create a peer group for BLPC due to its small size relative to other companies. Because evidence suggests that the cost of capital rises progressively with smaller-sized entities,[29] the cost of equity estimates derived from the analysis of the peer groups will be systematically low. Also, the estimation procedures, including the selection of the comparable risk peer groups, do not explicitly take account of business context differences—in particular, the isolation associated with the Company's island power system. This analysis explicitly estimates the likely range of sovereignty risk, which is incorporated into the cost of equity capital recommendation.

Peer Group Estimates of the Cost of Equity

The analysis draws on recent and long-term historical experience as the basis to determine the cost of equity capital, which incorporates capital risks and future prospects for capital returns. While estimates of the cost of capital are inherently forward looking, the process of estimation draws upon historical assessments of risk and the future prospects for market returns—essentially, the realized returns to investors and savers, as holders of property rights claims to capital in the form of financial assets. The tables below summarize the analysis conducted using the four approaches for the U.S. and Canadian[30] utilities and U.S. comparable risk non-utility companies. Details appear in Appendices III-VI at the end of the report.

[29] Size-related risk premia, within the context of CAPM analysis, are reflected in higher levels of CAPM Beta with progressively smaller entities. This empirical result is expected. However, it appears that CAPM Beta for smaller capitalization entities, though higher, systematically understates realized historical returns. This second component of the size premium is explicitly recognized in the Risk Premium cost of equity approach used in this study.

[30] The study does not apply the discounted cash flow ("DCF") methodology to the two samples of Canadian utilities because of the limits of reported financial data for a sufficiently long historical period. DCF is also not applied to the U.S. comparable risk non-utility sample because of non-applicability, in view of the sparse dividend experience of the sample, which is non uncommon for non-utility companies.

DISCOUNTED CASH FLOW ANALYSIS: U.S. Utilities

Mid-Sized Electric Utilities (U.S. sample 1)		
Estimated Cost of Equity (%)	**Dividend Yield (%)**	**Expected Growth In Cash Flows (%)**
10.32	4.66	5.66
Gas Distribution Utilities (U.S. sample 2)		
Estimated Cost of Equity (%)	**Dividend Yield (%)**	**Expected Growth In Cash Flows (%)**
10.86	3.38	7.49

CAPM ANALYSIS: Canadian, U.S. Utilities and Non-Utility Companies

Peer Group Samples	Estimated Cost of Equity (%)	Estimated Future Risk Free Rate (%)	CAPM Beta	Estimated Overall Market Risk Premia (%)
Canadian Utility Sample 1	10.39	4.64	0.87	6.63
Canadian Utility Sample 2	10.60	4.64	0.90	6.63
U.S. Mid-Sized Electric Utilities (U.S. sample 1)	11.28	4.73	0.81	8.07
U.S. Natural Gas Distribution Utilities (U.S. sample 2)	11.32	4.73	0.82	8.07
U.S. Comparable Risk Non-Utility Companies (U.S. sample 3)	10.35	4.73	0.70	8.07

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COMPARABLE EARNINGS[31] (Historical Market Returns_)

Peer Group Samples	Realized Returns (%)
Canadian TSX Listed Utilities (sample 1)	13.36
Canadian TSX Listed Utilities (sample 2)	16.07
Mid-Sized Electric Utilities (U.S. sample 1)	10.41
Gas Distribution Utilities (U.S. sample 2)	9.34
Comparable Risk Non-Utility Companies (U.S. sample 3)	10.75

RISK PREMIUM ANALYSIS: U.S. Utilities and Non-Utility Companies

Peer Group Samples	Estimated Cost of Equity (%)
Mid-Sized Electric Utilities (U.S. sample 1)	12.07
Gas Distribution Utilities (U.S. sample 2)	12.12
Comparable Risk Non-Utility Companies (U.S. sample 3)	12.71

The estimates of cost of equity capital using single-stage DCF analysis for each of U.S. samples 1 and 2 are quite similar: 10.32% for the sample of U.S. mid-sized electric utilities and 10.86% for the sample of U.S. moderate-sized gas distribution utilities.[32] The dividend yields of the DCF analysis utilize the stated dividend rates observed during early- to mid-2007, and stock prices sampled during April-May of 2007. The DCF cost of equity results for the electric utilities reflect the slowdown in earnings and cash flow growth during 2005 and continuing in 2006, which is largely a result of rising input costs, particularly for new investment, that is not being recovered in current rates. Expected growth relies on the historical experience for both internal cash flow and earnings per share.

[31] *Comparable Earnings* in the context of market-based assessment of realized returns is referred to as *Historical Market Returns* elsewhere in the report including the Appendices.

[32] The three-stage DCF model results are similar in magnitude and are thus not reported.

The *CAPM* cost of capital results utilize estimated betas for two samples of Canadian utilities, which are based on the period 2002 forward and estimated monthly.[33] In the case of the samples of U.S. companies, including utilities and non-utilities, the CAPM analyses are based on and utilize Valueline estimates of CAPM betas, which are estimated on a weekly frequency over a 60-month period. Both the Canadian and U.S. CAPM analyses incorporate the Blume adjustment for long-run central tendency of betas to evolve toward unity.[34] All U.S. samples draw upon more contemporary betas, as estimated over the 60-month period ending in 2006, as it appears that the underlying market risks of electric and gas utilities have risen somewhat in the contemporary period. In addition, betas are also shown as for a five-year average of rolling averages for successive five-year periods ending 2002 (1998-2002); 2003 (1999-2003); and so forth. The CAPM analysis of the non-utility U.S. companies also utilize betas for the period ending 2006, in view of the significant difference in the typical 2006-ending beta value with reference to the rolling average.

As can be seen in the attached Appendices, the forward-looking risk-free or riskless cost rates used within the CAPM framework are not consistently drawn. In the case of the Canadian CAPM analysis of the cost of equity, the risk-free rate is set at the observed yields for the benchmark 10-year issues on Canadian government bonds for the period 2002-2006 of 4.64%. This recent, historically observed value[35] closely conforms to the recorded yields for the benchmark 10-year Canadian government bonds for mid-2007, 4.60%, which is the timeframe in which the cost of equity capital is estimated.

[33] The analysis that obtains CAPM Betas for the Canadian utilities utilizes monthly yields on intermediate-term Canadian government debt as the surrogate for the risk-free rate. These yields are used for the determination of the historical risk premia for estimation of CAPM Betas. However, these yields are only an approximation to the market returns on risk-free asset which, to be precise, include both the flow of interest income as well as *ex post* market appreciation (or loss should bond prices decline over the course of the month).

[34] The so-called Blume methodology derives from the work of Marshall Blume, as first presented in the article, "On the Assessment of Risk," *Journal of Finance*, Vol. 26, 1971. The alternative approach to adjust the estimated raw Betas is the so-called Vasicek technique, as proposed by O.A. Vasicek in "A Note on Using Cross-Sectional Information in Bayesian Estimation of Security Betas," *Journal of Finance*, vol. 28, 1973. Generally speaking, the Vasicek approach is considered the preferred methodology though considerable information is required for implementation. Commercial financial services including Bloomberg, Compustat and Valueline, utilize the Blume approach, whereas Ibbotson Associates employs the Vasicek correction method.

[35] It is useful to note that the yields on Canadian long-term debt declined dramatically in 2002 from the previous two years (5.84% for 2000 and 10.88% for 2001).

For the U.S.-based analysis, the study also utilizes 10-year yields on U.S. government bonds recorded for recent years (2000–2006). For intermediate term bonds, the monthly average yields over these contemporary years, 4.73%, appear to match fairly well with investor expectations during mid-year 2007, with observed 10-year yields of 5.00% and 5.10% for June and July, respectively. Accordingly, this value (4.73%) serves well as a historically-based risk-free cost rate for the CAPM analysis for the three U.S. samples. Nonetheless, this bond yield level resides at about 85 basis points above current 10-year government bond yields, in view of the recent sharp decline in interest rates since December 2007. For reference, the 2006 inflation-indexed U.S. long-term government bond yield resides at 2.53%, suggesting an expected 2.5% rate of overall price inflation (5.00% or 5.10% minus 2.53%) for the U.S., which is best captured historically by the chain-weighted gross domestic product (GDP) price deflator.

When applied to the Canadian and U.S. samples, the CAPM analysis obtains similar results, with the cost of equity estimates ranging from 10.35% for the Comparable Risk Non-Utilities (U.S. sample 3) to 11.32% for the U.S gas distribution utilities (U.S. sample 2. The corresponding CAPM results for the Canadian samples 1 and 2 are 10.39% and 10.60%, respectively.

The *Comparable Earnings* (Historical Returns) approach of our overall framework for estimation of cost of equity capital is in keeping with a market-based analysis. As a matter of interpretation, the Comparable Earnings approach, otherwise known as Historical Market Returns, provides the only relevant basis for determining the realized returns to capital. To a substantial extent, history is the basis upon which investors form expectations. In fact, the historical market returns interpretation of the Comparable Earnings basis is well founded by empirical evidence of capital market experience. For this reason, we draw upon the historical market returns realized by the four samples of Canadian and U.S. utilities as well as the U.S. comparable risk non-utility companies (U.S. sample 3). The realized market returns generally conform to the forward-looking estimates of cost of capital, including DCF, CAPM, and Risk Premium, where the reported realized returns range from 9.34% for Moderate-Sized U.S. Gas Distribution Utilities (U.S. sample 2) to 13.36% for Canadian sample 1. The realized historical returns for Canadian sample 2 appear to be unusually high (16.07%) and may overstate the cost of equity capital if accepted in isolation of the valuation results for the other methods and samples. Accordingly, the cost of capital study results reported here do not incorporate Canadian sample 2 realized historical returns. These results do not require explanation, though we wish to mention that the historical returns shown in the Appendices incorporate the combined impact of realized dividends as well market appreciation.

Finally, we wish to note that the interpretation of Comparable Earnings as either book returns to capital or authorized returns, as is so often the case, constitutes a clear example of circular reasoning, where regulators set authorized returns on a basis of book returns set by others. This results in book returns potentially departing from the underlying cost of capital by substantial margins. Thus, we suggest that the Fair Trading Commission, in its deliberation of return on equity employ reasonable caution in referring to realized book returns on equity as surrogates for estimates of the cost of equity, for the determination of the rate-of-return level for BLPC.

The *Risk Premium* approach to valuation draws upon observed historical risk premia across realized market returns for classes of debt and equity vehicles. Risk premia can be calculated in many ways. The analyses, here, draw upon the risk premia reported and published by Ibbotson Associates. The analyses suggest that efficient capital markets demand substantially higher market rates of return on equity vis-à-vis debt of various terms. Specifically, equity risk premia are reported with respect to short-, intermediate-, and long-term government debt. We summarize risk premia in selected pages of Appendices III-V.

Cost of Equity Capital and Firm Size

It is worth noting that extensive analysis of realized returns within U.S. equity markets reveals that progressively higher equity risk premia—and, thus, cost of capital—attend small-sized companies, particularly for micro-sized companies like BLPC. For this reason, our estimated cost of capital results and rate of return recommendations are conservative and, in fact, may understate the underlying cost of capital for BLPC.

Risk premia associated with small size, sometimes referred to as small capitalization risk premia, reflect intuition, well established principles that serve as the foundation of finance theory, and the observed realities of capital markets. First, ordinary common sense would lead one to recognize that small entities face higher business risks than large entities. Higher risks attending small size come about from the principle of large numbers. Specifically, the financial impacts of random business events, which occur over the course of business enterprise, cannot be diversified by small entities as well as by large entities. Essentially, the impacts of business events within larger enterprises get absorbed within a pool of other events, both positive and negative, with the result that such events are substantially muted in their total impacts on the financial results of the enterprise.

The intuitive idea of diversification of business activity is reflected in portfolio theory. In this regard, the larger entity can be viewed as, essentially, a larger portfolio of individual business activities with the attending diversification effects, providing that individual business activities have less than perfect correlation.

Capital markets reveal that, among other factors, the variability of the returns to capital, reflected as operating income, will typically be higher for smaller entities than larger entities. Second, historical market returns for entities with smaller market capitalization will have higher variation than for entities with higher capitalization levels. Within the context of CAPM theory, the core of modern finance theory, the relevant and well known measure of risk is the covariation of market returns of individual equities with the market as a whole, normalized by the variance of the overall market, referred to as CAPM Beta. Insofar as this notion of risk—*i.e.*, systematic risk—is the only relevant measure of risk given optimal portfolio theory, competitive capital markets would ensure that equities are priced at levels such that the realized market returns of individual equities would be ordered according to CAPM Betas.

Essentially, CAPM theory would then suggest that, to the degree that the higher risks of small capitalization entities can be diversified—*i.e.*, are non-systematic—CAPM Betas would still reflect the most relevant risks. To the degree that higher risks of small capitalization entities cannot be fully diversified—*i.e.*, are systematic—higher risks are reflected in higher CAPM Betas.

Empirical evidence suggests that while CAPM Betas are typically higher for smaller-sized equities, CAPM Betas do not fully explain the higher realized market returns of small capitalization entities. Indeed, a substantial body of evidence suggests that CAPM underestimates—and thus understates—historical market returns of small firms. In one interpretation, the difference between the realized market returns of small capitalization firms and the estimated market returns under CAPM constitutes *the small-capitalization risk premium. A second interpretation is that, after* accounting for various factors, it appears that size, as reflected in capitalization, is inversely related to historical market returns and that the relationship is systematic – both repeatable and non-random. The magnitude of small capitalization risk premium is large, as best demonstrated by the published analytical work of Ibbotson Associates, Eugene Fama and Kenneth French, Banz, Kaplan, and Roger Ibbotson. In the latest published work, the analyses of Ibbotson Associates[36] demonstrate that for entities organized into deciles according to capitalization, as a measure of size, size-related risk premia not captured by CAPM Beta assume the magnitudes presented in the table below.

SIZE-RELATED RISK PREMIA IN EXCESS OF CAPM[37]

Size Decile	Size-Related Risk Premium (%)
1	-0.36
2	0.65
3	0.81
4	1.03
5	1.45
6	1.67
7	1.62
8	2.28
9	2.70
10	6.27

[36] *SBBI Valuation Edition Yearbook* by Ibbotson Associates, 2007.

[37] The deciles organize equities into capitalization groups, where the largest entities are within Decile 1, and the smallest entities are within Decile 10.

It is useful to mention that, as reported, Decile 9 includes entities with market capitalization of $265.1-$586.4 million, while Decile 10 includes entities with market capitalization of $1.1-265.0 million. Recent studies by Ibbotson Associates have further segmented Decile 10 into larger and smaller entities, with results that confirm the pattern shown above, with the smaller group of entities within Decile 10 demonstrating very high size-related premia not captured within CAPM Beta. Excess market return (and cost of equity capital) not captured by CAPM—*i.e.*, size-related risk premium—appears to rise with progressively smaller sized entities. In addition, size premia are specific to industry and, generally speaking, we can infer that the size premium for electric utilities is somewhat smaller than for other industries. For the U.S. samples 1 and 2, industry-specific size-related risk premia are utilized in the study, though the industries are rather broadly defined.

CAPM theory, when used in isolation from other valuation methods, can be challenged for a number of reasons that warrant consideration for purposes of setting the rate of return for BLPC. In terms of size-related risk premia, the reasons for the understatement of market returns by CAPM for small-sized entities are perhaps not widely understood at this time. Our general view, however, is that, for small entities, the cost of acquiring information regarding the prospects for future returns and assessment of risks is unusually high. Because the acquisition of information is costly, less information and knowledge within the investment community about small entities is available. Hence, investors with positions in small entities inherently incur higher risks. For small-sized entities, higher returns are thus the compensation for the assumption of higher risks. It is useful to emphasize that CAPM over long timeframes does reveal higher risk premia and cost rates for smaller entities. However, and as discussed here evidence also suggests that CAPM systematically understates risk premia, and thus the cost of capital, attending comparatively small sized equity listings. The study's Risk Premium analysis, which is based on the CAPM framework and explicitly incorporates sized-related risk premia not captured by CAPM Beta, is incorporated into the analysis for the three U.S. samples, and finds that the cost of equity capital ranges from 12.07% to 12.71%. The size premium not captured by CAPM included within this range is estimated at a level of 1.20-1.60% for both the U.S. electric utilities (U.S. sample 1) and U.S. gas utilities (U.S. sample

2), and 1.90-3.90% for comparable risk non-utility companies (U.S. sample 3).[38] Size-related premia have been extensively studied, for U.S. equity markets, and have also been shown to be present within equity market experience, internationally.

Cost of Equity Capital and Sovereignty Risk

The estimates for the cost of equity above do not incorporate any allowance for sovereignty risks. As we have discussed, sovereignty risk refers to risk differences of financial assets sourced across various sovereign countries. Such risks are relevant to the outstanding debt of public and private entities and common stocks that are traded either on exchanges of emerging economies. Sovereignty risks are also relevant to over-the-counter traded securities. To better understand and estimate country risks, the study employs two general methods, referred to as *Credit Score Differences* and *Relative Risks of Equity Market Returns*. The first approach, *Credit Score Differences*, utilizes the surveys of securities traders involved in the assessment of financial markets of global capital markets. The second approach, *Relative Risks of Equity Market Returns* is based on the relative risks (statistical variance or standard deviation) of historical market returns for exchanges of emerging nations, with respect to exchange indexes of developed markets such as the U.S. NYSE Composite or S&P500 equity market indexes.

The *Credit Score Differences* utilizes the 2007 survey of credit scores conducted by *Institutional Investor*,[39] where the survey-based study results in credit scores of countries, with 174 countries included in the survey.[40] The approach estimates the statistical relationship between observed real interest rates among countries and the survey-based credit scores. Once estimated, the statistical relationship is then used as the basis to estimate the likely difference in short-term real interest rates (risk premium) that results from credit score differences, where the U.S. or a group of developed countries with high credit ratings serve as the benchmark.

[38] For the industry segment grouping that includes electric utilities, Ibbotson Associates reports a size premium of 3.20% for small entities relative to large. However, this level incorporates a premium that is captured by CAPM Beta although the effects are very small. Second, this size premium level is for a fairly heterogeneous industry group.

[39] Institutional Investor conducts its survey semi-annually.

[40] A similar approach would be to utilize the credit ratings assigned by risk assessment and credit rating service entities, such as Moody's, S&P, and Fitch. The credit ratings would need to assigned numeric values that are then used as the basis to gauge real interest rate differences.

The credit rating scores range up to a potential score of 100. Worldwide, Switzerland earns the highest survey-based credit score of 96.40, with the lowest score of 4.70 assigned to Somalia. The *Institutional Investor* survey-based credit scores are shown below for selected countries, including Barbados and several neighboring countries.

The study covers all sovereignties for which positive real short-term interest rates are reported. Of this sample of 73 countries, the statistical analysis is conducted on credit score and interest rate data for 55 counties with credit scores no less than 40.00, with Nigeria having the lowest included credit score. The analysis is conducted using two sets of data, including 1) individual country credit scores and real short-term interest rates, and 2) 10-observation averages of credit scores and interest rates. The analysis results suggest that short-term real interest rates rise by 4.1 to 4.8 basis points for each 1.0 point decline in credit score. With the U.S. serving as the benchmark low credit risk country (credit score 94.10), the estimated sovereignty risk premium for Barbados is from 1.25% to 1.48%. Using the average credit scores for selected Caribbean neighbors of Barbados including Bahamas, Trinidad & Tobago, and Jamaica, the analysis obtains an implied level of sovereignty risk premium for the group ranging from 1.45% to 1.72%.

The *Relative Risks of Market Returns* analysis is based on annual market indexes for three Caribbean stock exchanges including those for Barbados, Trinidad & Tobago, and Jamaica. Of the Caribbean exchanges, the Barbados Stock Exchange has the longest history, with its composite index reaching back to 1989. The index for the Trinidad and Tobago stock exchange is available from 1997, while the index for the Jamaican Stock Exchange is available from 2001. The S&P 500 index is used as the benchmark exchange index in view of its market capitalization and because of its wide recognition as an overall indicator of market performance. The analysis calculates annual market returns for the stock market indexes (without recognition of dividends), and the statistical variance of market returns, as shown below.

(see following page)

ANNUAL MARKET RETURNS FOR CARIBBEAN STOCK EXCHANGES[41]

Year	Barbados Stock Exchange	Jamaican Stock Exchange	Trinidad & Tobago Stock Exchange	S&P 500 Index
1990	-13.24%			-6.56%
1991	1.58%			26.31%
1992	-15.37%			4.46%
1993	19.92%			7.06%
1994	6.28%			-1.54%
1995	-5.38%			34.11%
1996	-0.03%			20.26%
1997	50.52%			31.01%
1998	47.58%		23.86%	26.67%
1999	-8.37%		-4.32%	19.53%
2000	-14.23%		5.76%	-10.14%
2001	-6.25%		-1.66%	-13.04%
2002	10.55%	34.21%	25.65%	-23.37%
2003	29.04%	48.88%	27.23%	26.38%
2004	26.36%	66.68%	54.82%	8.99%
2005	5.83%	-7.23%	-0.68%	3.00%
2006	-6.77%	-3.67%	-9.20%	13.62%
Cumulative Realized Historical Returns	5.82%	24.38%	11.90%	8.52%
STATISTICAL VARIATION IN MARKET RETURNS				
1990 - 2006	20.57%			16.94%
1998 - 2006			20.84%	18.0%
2002 - 2006		32.46%		18.4%

As expected, the Caribbean exchanges reveal substantially higher risks (variation of realized returns) than U.S. equity markets, as represented by the S&P 500 index.

Estimates of sovereignty risks constitute real capital cost differences, and are implicitly present in the differences in *ex ante* equity market returns between the Caribbean region and U.S. markets, as reflected in, for example, the S&P 500 index. On average, risk premia with respect to intermediate term debt for the S&P 500 index

[41] While the Jamaican Stock Exchange is shown above, the study does not utilize experience from the Jamaican exchange because of insufficient history from which to estimate relative risks.

have ranged from 5.5% to over 8.0% for the period 1970 forward. Using values of 6.0% and 8.0%, the incremental risk premium associated with the Barbados Stock Exchange is equal to (20.57%/16.94% -1)*(6.0 to 8.0)%, or 1.12% to 1.72%. Incorporating the experience of the Trinidad & Tobago Stock Exchange into the analysis yields a similar level of 1.29%-1.49%.

In summary, the Credit Score Differences and Relative Risks of Equity Market Returns obtain a sovereignty risk premium for Barbados ranging from 1.12% to 1.72%, with an average value of 1.43%.[42]

Analysis Summary

The cost of equity studies described above draw upon the cost of capital tool box and provide reliable and well-grouped estimates for return on equity. The cost of equity estimates result from the application of the valuation methods to two Canadian utility samples and three U.S. samples including two groups of utilities and a group of comparable risk non-utility companies. The results range from 8.65% to 11.51%, notwithstanding the exceptionally high Historical Market Returns (Comparable Earnings) realized for the Canadian utilities, sample 2.

These comparable risk peer group estimates of the cost of equity likely understate BLPC's cost of equity for several reasons. It is essential that several factors not incorporated directly into the cost of equity capital studies, as reviewed above, be presented and fully accounted for, as follows:

- *Issuance Costs*: The analyses do not incorporate issuance costs which, for very small entities, are likely to be upwards of 7.00-9.00% of the realized proceeds from the sale of equity securities in order to cover registration fees, audit fees, and the charges for underwriting and marketing the securities. Recognition of issuance costs typically translates into approximately 30-40 basis points. Only a portion of the incremental equity capital of Barbados Light and Power is likely to be obtained from external sources[43]—*i.e.*, through the sale of new shares—which implies that, to determine the opportunity cost

[42] Also, this estimated range of the level of sovereignty risk is paralleled by the difference between the real risk-free interest rates of Central Bank debt of Barbados and the U.S., as presented earlier within the Report.

[43] The remainder of new equity capital of the firm is raised internally, and shows up in the ongoing accrual of retained earnings.

of equity, the effective adjustment for issuance costs is less. This is because issuance costs are applicable only to the share of incremental capital raised externally. Three basis points (0.03%) are incorporated into the return on equity recommendation.

- *Isolation Associated With An Island System*: As the report discusses, the Barbados Light and Power Company serves an island economy and is thus not part of the larger integrated systems of the major continent. Accordingly, BLPC is exposed to an unusual business context resulting in inherently higher operating risks than the risks of continental firms making up the peer group of comparable risk entities for which the cost of equity estimates are determined. No specific cost rate adjustment is incorporated into the return on equity recommendation for isolation.

- *Size-Related Risk Premium*: Size premia for very small entities are explicitly captured only within the Risk Premium cost of equity capital methodology, as applied to the U.S. sample companies. While, in the absence of further research, we cannot be sure, it is likely that the cost of equity for BLPC is somewhat understated for this reason. As reported, the size-related risk premium appears to be in the range of 1.20-1.60% for comparable risk utilities, and noticeably higher for non-utility companies. In conservative fashion, a range of size premia of 1.20% (low) and 1.60% (high) is applied to the market-based estimates of the cost of equity.[44]

- *Sovereignty Risks*: Because the technical estimates of the cost of equity capital are obtained from samples drawn from North America, such estimates do not incorporate sovereignty risks specific to Barbados or its neighbors in the Caribbean region. Based on two methods used in the study—including Credit Score Analysis and Relative Risks of Market Returns—country risks are likely to range from 1.12% to 1.72%, with an average of 1.43%.

- *High Equity Participation*: The weighted average cost of capital incorporates fairly high equity participation of 65%, when compared to the sample of

[44] The adjustment is factored appropriately in order to not "double count" the size-related risk premium, which is explicitly incorporated with the Risk Premium analysis.

comparable risk U.S. electric and gas distribution utilities. BLPC's comparatively high equity share is necessary in view of business context, an isolated island system facing substantial capital expenditures. Nonetheless, because increased equity share in total capital reduces capital risks, other factors constant, the Company's high equity participation translates into a downward adjustment to the cost of equity. A downward adjustment of 51 basis points is incorporated in the study results.[45]

- *Quarterly Payment of Dividends*: Where relevant, the quarterly payment of dividends typically yields an upward adjustment of 20-30 basis points. The cost rate adjustment for quarterly payments is 25 basis points.

The cost of equity study suggests that the return on equity averages 11.16%, with a range from 9.34 to 13.36%, as far as the market-based cost estimates are concerned. [46] (As mentioned above, the study declines to include the extreme value of 16.07% realized historical returns for Canadian sample 2.)

Taking full account of the above adjustment factors suggests, moreover, that the cost of equity capital for BLPC resides at a level well above the market cost estimates that are obtained from the five North American samples. These adjustment factors, moreover, are additive. Taking a conservative view of the adjustment factors through recognition of lower estimated values for size premia and sovereignty risks results in a minimum adjustment of 2.05%. Alternatively, utilizing the upper level risk premium estimates for size and sovereignty risks lead to an adjustment level of 2.71%. This range of adjustment can be viewed as upper and lower bounds—2.05% and 2.71%, respectively. Applying these adjustment factors to the estimate of 11.16% for the market cost of equity for North American utilities obtains an adjusted cost of equity for the Company of 13.18% to 13.85%, with 13.51% the average.

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[45] The adjustment amount, in basis points, is related to the sensitivity of the cost of common equity, as a matter of assumption, to the impact of an increase in equity share on the volatility in earnings and cash flow per share equity returns. However, the adjustment does not account for the samples of companies used in the study, including Canadian samples 1 and 2 and the U.S. non-utility company sample (sample 3), which have equity participation of 70%, thus more closely approximating that of BLPC.

[46] This value is obtained by calculating the average of the cost of equity estimates that result from the four methodologies. In addition, the average of all the individual market cost of equity estimates (excluding the 16.07% for Canadian sample 2) is virtually identical (11.13%).

Accordingly, we recommend that The Barbados Light & Power Company Limited adopt, in its filing before the Fair Trading Commission, 13.50% for Return on Equity.

WACC and RATE OF RETURN: BARBADOS LIGHT AND POWER

As mentioned, the weighted average cost of capital incorporating the weighted cost rates for both traditional components and non-traditional elements[47] is the basis for determination of the overall rate of return. For the development of the WACC and the overall rate of return, an appropriate starting point is the observed capital structure stated on a traditional basis. For the test period 2007, BLPC underwrites its assets with the following capital structure, shown with capitalization shares and corresponding cost rates:

WEIGHTED AVERAGE COST OF CAPITAL FOR CONVENTIONAL CAPITAL STRUCTURE
Based on Total 2007 Balances

Capital Component	Observed Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$115,406	21.44%	5.25%	1.13%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$422,804	78.56%	13.50%	10.61%
Total	$538,210	100.00%		11.73%

As can be seen, the Company is financing assets with an unusually high concentration of equity participation, resulting in a weighted average cost of capital (overall rate of return), not including income tax effects, of over ten percent. Viewed in the context of the capital structure experience of the industry, the Company's high equity participation may cause the Company's WACC to depart from a least-cost level, although the Company's unusual business context provides reason for equity to remain at a fairly intensive level and above that of the electric power industry as a whole. Accordingly, we recommend that the Company, within its upcoming submission before the Fair Trading Commission, utilize a capital structure that departs from BLPC's observed capital structure. Specifically, we recommend consideration

[47] Traditional financing vehicles include long- and short-term debt, preferred and preference stock, and common equity. Non-traditional elements include customer deposits, deferred balances of income taxes, investment tax credits and, for Barbados, the manufacturers' allowance.

of a policy-based imputed capital structure that contains 65% equity participation. The WACC associated with this policy-based capital structure is shown below:

WEIGHTED AVERAGE COST OF CAPITAL FOR POLICY-BASED (IMPUTED) CONVENTIONAL CAPITAL STRUCTURE
Based on Total 2007 Balances

Capital Component	Implied Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$188,374	35.00%	5.25%	1.84%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$349,837	65.00%	13.50%	8.78%
Total	$538,210	100.00%		10.61%

As can be seen, reducing equity participation from 79% to 65% lowers the weighted average cost of capital by over 110 basis points. The imputed capital structure shown above significantly reduces equity participation, while also sustaining sufficient equity and debt-equity balance. This result, we believe, is consistent with the least cost financing mix for the Company's capital resources given its inherent business context and risks, while also providing BLPC with a satisfactory level of interest coverage.

The proposed approach is in keeping with the capital attraction and financial integrity concepts of fair rate of return principles. The 65% participation of equity is plentiful—a level that is above that of most mid-sized and large electric utilities in the U.S., though a number of registered Canadian utilities tend to utilize equity participation levels that are equivalent to or above those of their U.S. counterparts. This level of equity participation is adequate and desirable, when viewed from the Company's unusual business context and small size.

The policy-based traditional capital structure with 65% equity participation provides the basis for the regulatory capital structure that, as mentioned, incorporates both traditional and non-traditional capital components, as follows:

RATE OF RETURN RECOMMENDATION:
WEIGHTED AVERAGE COST OF CAPITAL FOR
REGULATORY CAPITAL STRUCTURE
Based on Total 2007 Balances

Capital Component	Balances ($ 000)	Capitalization Shares	Cost Rates	Weighted Cost Rate
Long Term Debt	$188,374	31.32%	5.25%	1.65%
Short-Term Debt	$0	0.00%	0.00%	0.00%
Common Equity	$349,837	58.17%	13.50%	7.85%
Customer Deposits	$20,010	3.33%	6.46%	0.22%
Deferred Investment Tax Credits	$30,099	5.00%	10.61%	0.53%
Deferred Manufacturers' Allowance	$13,052	2.17%	10.61%	0.23%
Total	$601,371	100.00%		10.48%

The inclusion of non-traditional elements such as the manufacturers' allowance, when "costed" at the policy-based WACC level, results in an overall cost of capital that is slightly lower, 10.48%, whereas the policy-based WACC is 10.61%. We recommend that BLPC adopt a WACC (and overall rate of return recommendation) of 10.48% within its upcoming submission in the current regulatory proceeding to the Fair Trading Commission, for the purpose of setting retail prices for electricity services.

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TECHNICAL APPENDICES

APPENDIX I

PRESENT VALUE OF INVESTMENT AND DERIVATION OF THE CONSTANT GROWTH AND MULTI-STAGE DISCOUNTED CASH FLOW MODEL (DCF)

Present Value Theory

As wages are the compensation to labor, interest is the compensation or return to savings and capital. Savings is the share of current income held back to be consumed in later periods. A unit of current consumption has greater value than an equivalent amount of consumption later. Hence, savings must obtain greater consumption later, in order to compensate for its reduced (discounted) value.

The inducement to save is interest; essentially, the accrual of interest on savings offsets the reduction in value of later consumption vis-à-vis current consumption. Without the expectation of interest, savings would be largely exhausted as consumption in the current period. Savings are invested and, over time, give rise to and constitute the accumulation of capital. Savings realize the market rate of interest. Savings and investment—and thus the accumulation of capital—rise as expected interest increases.

Returns to savings, investment, and capital can be viewed as cash flow returns, and can be stated as an annual percentage amount. Cash flows in subsequent periods forego the interest that would have accrued on earlier cash flows. Because of foregone interest, later cash flows are worth less than those of earlier periods by the amount of interest that would have been realized on the earlier flows.

Cash flows over time can be ordered with a discounting procedure commonly known as present value. Present value revalues future cash flows according to the accrual of interest that would have been realized, had they occurred in the present. Specifically, the cash flow within a time step is discounted by a factor equal to the inverse of one plus the market rate of interest, k, compounded by time – $(1/(1+k))^t$. The present value procedure can be shown more formally as:

$$PV = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n} \qquad (1)$$

or,

$$\sum_{t=1}^{n} \frac{CF_t}{(1+k)^t} \qquad (2)$$

where,

PV = present value

CF_t = cash flow in time t

k = market cost (rate) of interest.

Hence, $1/(1+k)^t$ is the discount factor by which the cash flows at time t are reduced.

Present value analysis equates cash flows at different points in time to the present, and constitutes a fundamental principle of financial and investment analysis. Essentially, present value normalizes the cash flows at the market rate of discount.

Consider a cash flow occurring at time, $t=0$. Since the cash flow occurs in the present and, unlike the subsequent cash flows shown in (3), below, no interest is foregone and thus it is not discounted:

$$NPV = CF_o + \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n}. \qquad (3)$$

Presume that a savings agent, a household, invests savings. The purchase of an investment or financial asset such as securities or other liquid assets by the agent constitutes a negative cash flow – an outflow of money. It is the expectation of positive cash flows later that induces the purchase. Positive cash flows prospectively, as expected, tend to balance the negative cash outflow associated with the purchase of the asset. All negative and positive cash flows are contained in net present value, as shown in (4) below:

$$NPV = -CF_o + \sum_{t=1}^{n} \frac{CF_t}{(1+k)^t} \qquad (4)$$

where,

$NPV =$ net present value – *i.e.*, the net of all positive and negative cash flows

If net present value (NPV) is positive, the investment action is "economic" in the sense that the expected positive cash flows, discounted at the market cost of capital, are greater than—or at least equivalent to—the purchase price of the asset, the negative flow.

Competitive capital markets—or the processes of market competition—seek to discover and exhaust all opportunities for positive and negative present values. That is, the *expected* NPV of investment opportunities approximates zero, given the implicit rate of discount harbored by investors. Essentially, the market value of assets is driven to its competitive level prospectively because of arbitrage inherent to competitive markets. Market forces bid prices up in the presence of expected positive returns (NPV), or bid prices down if negative returns are expected. The discounted positive cash flows equate to and balance the purchase cost of the asset, as shown in (5), below:

$$CF_o = \sum_{t=1}^{n} \frac{CF_t}{(1+k)^t}. \qquad (5)$$

In market equilibrium, then:

$$P_o = \frac{CF_1}{(1+k)^1} + \frac{CF_2}{(1+k)^2} + \frac{CF_3}{(1+k)^3} + \cdots + \frac{CF_n}{(1+k)^n} \qquad (6)$$

$$P_o = \sum_{t=1}^{n} \frac{CF_t}{(1+k)^t} \qquad (7)$$

where,

P_o = market price at time $t=0$.

The market cost of capital implicitly incorporates investor's perceptions of risk and expectations about inflation over the life of future cash flows. It is straightforward to solve for the market cost of capital, k, as we are confronted with one equation and one unknown value. For example, to solve for the internal rate of cost of a debt obligation of a borrowing firm, such as bond, simply determine the internal rate of discount that equates the positive cash flow occurring at time zero, CF_o, and the negative flows, -ΣCF_t, which represent the annual interest cost and retirement of the principle. The discounted negative cash flows from the perspective of the borrowing firm can be shown as $-\Sigma CF_t/l1+k)^t$. The analysis problem for lenders is precisely the same except that the signs attending the cash flows are reversed. Hence, the rate of discount is both the opportunity cost of capital to investors, given market arbitrage, and the cost of capital to the borrowing firm.

Constant Growth Discounted Cash Flow

For equity capital, investors' expected earnings reflect expectations of future cash flows associated with shares of stock, and thus determine the stock price currently. Assume that investors expect earnings, E_t, and dividends, D_t, to grow at some constant rate, g, over the future, such that:

$$E_t = (1+g)E_{t-1} \tag{8}$$
$$E_1 = (1+g)E_o$$
$$E_2 = (1+g)E_1 = (1+g)^2 E_o$$
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$$En = (1+g)^n E_o.$$

Dividends of course are a function of earnings and therefore represent, along with price appreciation, the discounted cash flows. Dividends can thus be shown similarly to that of earnings, as below:

$$D_t = (1+g)D_{t-1} \tag{9}$$
i.e., $$D_1 = (1+g)D_o$$
$$D_2 = (1+g)D_1 = (1+g)^2 D_o$$
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$$D_n(1+g)^n D_o.$$

Further, assume that dividends, D_t, are a fixed share, m, of earnings, E_t, such that:

$$D_t = mE_t \quad \text{and,} \quad D_t / E_t = m.$$
(10)

From equation (8), then:

$$D_t = m(1+g)E_{t-1}$$

(11)

and, $D_n = m(1+g)^n E_o$.

Restating equation (7) to represent dividends as a fixed share of earnings which are paid out, provides:

$$P_o = \sum_{t=1}^{n} \frac{mE_t}{(1+k)^t}$$

(12)

$$= \frac{mE_1}{(1+k)^1} + \frac{mE_2}{(1+k)^2} + \frac{mE_3}{(1+k)^3} + \cdots + \frac{mE_n}{(1+k)^n}.$$

Observation will disclose that in fact the payout ratio is volatile and tends to offset the volatility in earnings so that dividend growth (realized cash flows) is smoothed.

Equation (12) can be restated to read:

$$P_o = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \frac{D_3}{(1+k)^3} + \cdots + \frac{D_n}{(1+k)^n}$$

(13)

$$= \sum_{t=1}^{n} \frac{D_t}{(1+k)^t}.$$

The relationship between D_{t-1} and D_t is simply $(1+g)$, which is also the relationship between E_{t-1} and E_t defined in (8). And, with an assumed constant payout ratio or share of earnings, the following is obtained:

$$P_o = \frac{D_o(1+g)}{(1+k)} + \frac{D_o(1+g)^2}{(1+k)^2} + \frac{D_o(1+g)^3}{(1+k)^3} + \cdots + \frac{D_o(1+g)^n}{(1+k)^n}$$

(14)

$$= \sum_{t=1}^{n} \frac{D_o(1+g)^t}{(1+k)^t}.$$

Now, assume an infinite time horizon:

$$P_o = \frac{D_o(1+g)}{(1+k)} + \frac{D_o(1+g)^2}{(1+k)^2} + \frac{D_o(1+g)^3}{(1+k)^3} + \cdots + \frac{D_o(1+g)^\infty}{(1+k)^\infty}.$$

(15)

Equation (15) above is simply a geometric series with a growth and discounting parameter, $(1+g)/(1+k)$, that defines the relative value of any two sequential terms.[48] Therefore, (15) may be expressed as:

$$P_o = \frac{D_o(1+g)}{(1+k)}\left[\frac{1-[(1+g)/(1+k)]^{\infty}}{1-(1+g)/(1+k)}\right].$$

(16)

And since $[(1+g)/(1+k)]^{\infty}$ is zero,[49] and $(1-(1+g)/(1+k))$ is equal to $(k-g)/(1+k)$, the following form can be obtained:

$$P_o = D_o(1+g)/(k-g).$$

(17)

Multiplying through by $(k-g)$ and $1/P_o$, and rearranging gives:

$$k = D_o(1+g)/P_o + g.$$

(18)

This is the derived form of the constant growth Discounted Cash Flow model.

In addition, the assumption of an infinite time horizon can be relaxed. Assume that the investor has a finite time horizon, n, with a salvage value equal to P_n and a constant price-earnings ratio. Equation (14) is then restated as:

$$P_o = \sum_{t=1}^{n}\frac{D_o(1+g)^t}{(1+k)^t} + \frac{P_n}{(1+k)^n}.$$

(19)

Since $P_o/E_o = P_n/E_n$, $P_n = P_o(1+g)^n$. Thus, (19) can be restated as:

$$P_o = \sum_{t=1}^{n}\frac{D_o(1+g)^t}{(1+k)^t} + \frac{P_o(1+g)^n}{(1+k)^n}.$$

(20)

The first term on the right may be restated as described above, and incorporated into (20), shown below:

$$P_o = \frac{D_o(1+g)}{(k-g)}\left[1-(1+g)^n/(1+k)^n\right] + P_o(1+g)^n/(1+k)^n.$$

(21)

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[48] With $(1+g) = d$, and $(1+k) = r$, a series of the form:

$$\sum_{t=1}^{n} a(d/r)^t = a\sum_{t=1}^{n}(d/r)^t.$$

This may be alternately expressed as:

$$a\frac{d}{r}[(1-(d/r)^n)/(1-(d/r))].$$

[49] If $k>g$

Rearranging and simplifying terms obtains:

$$P_o - P_o(1+g)^n/(1+k)^n = \frac{D_o(1+g)}{(k-g)}[1-(1+g)^n/(1+k)^n]$$

(22)

or,

$$P_o[1-(1+g)^n/(1+k)^n] = \frac{D_o(1+g)}{(k-g)}[1-(1+g)^n/(1+k)^n].$$

Now, dividing both sides by $[1-(1+g)^n/(1+k)^n]$ gives an equivalent result to (16):

$$P_o = D_o(1+g)/(k-g).$$

(23)

Rearranging terms provides:

$$k = D_o(1+g)/P_o + g.$$

(24)

Thus, the constant growth form of Discounted Cash Flow is derived for a finite time horizon.

Multi-Stage DCF

The model of constant growth over the future holding period may not be a fully satisfactory representation of investor expectations under some market conditions. The constant growth form can be generalized to a varying growth path or growth with stochastic elements. Such approach increases complexity.

As a practical matter, a useful extension of the constant growth model known as multi-stage DCF can be easily developed. Arguably, multi-stage DCF presents a platform for a more accurate representation of expectations of growth harbored by investors. A derived form of the multi-stage form is developed below:

Multi-stage DCF can be shown as a restatement of Equation 14 with three patterns or rates of growth applicable to specific forward timeframes or stages:

$$P_o = \sum_{t=1}^{5}\frac{D_o(1+g_1)^t}{(1+k)^t} + \sum_{t=1}^{5}\frac{D_5(1+g_2)^t}{(1+k)^t}(1/(1+k)^5) + \sum_{t=1}^{\infty}\frac{D_{10}(1+g_3)^t}{(1+k)^t}(1/(1+k)^{10})$$

(25)

Each stage can be shown in a simplified form. We begin by separating out the first stage, S_1 – *i.e.*, the first rhs term with growth = g_1 – as follows:

$$S_1 = \sum_{t=1}^{5}\frac{D_o(1+g_1)^t}{(1+k)^t}.$$

(26)

Pulling out the initial rate of dividends, D_0, from the sum,

$$S_1 = D_o \sum_{t=1}^{5} \frac{(1+g_1)^t}{(1+k)^t}.$$

Presenting the ratio of the growth and discount factors as a single term, $F = \frac{(1+g_1)}{(1+k)}$,

and incorporating F into the sum, $S_1 = D_o \sum_{t}^{5} F^t$.

The sum can then be expanded as follows:

$$S_1 = D_o \left(F^1 + F^2 + \cdots + F^5\right).$$
(27)

Defining a new term equal to unity, $\frac{(1-F)}{(1-F)}$, and including the term into the rhs of Equation 27:

$$S_1 = D_o \left(F^1 + F^2 + \cdots + F^5\right)\left(\frac{(1-F)}{(1-F)}\right),$$ and then expanding,

$$S_1 = D_o \left(\left(F^1 + F^2 + \cdots + F^5\right) - \left(F^2 + F^3 + \cdots + F^6\right)\right)/(1-F).$$
(28)

Canceling terms of Equation 28 provides, $S_1 = D_o(F^1 - F^6)/(1-F)$, and then collecting common terms gives a simplified result, as follows:

$$S_1 = D_o F^1 (1-F^5)/(1-F).$$
(29)

Expanding F in Equation 28 provides,

$$S_1 = D_o \left(\frac{(1+g_1)}{(1+k)}\right)\left(1 - \left(\frac{(1+g_1)}{(1+k)}\right)^5\right) / \left(\frac{(1+k)-(1+g_1)}{(1+k)}\right).$$

Finally, canceling terms to simplify Equation 29 provides the result,

$$S_1 = D_o (1+g_1)\left(1 - \left(\frac{(1+g_1)}{(1+k)}\right)^5\right)/(k-g_1).$$
(30)

The above result for Stage 1 can be stated as follows,

$$S_1 = D_o \left(\frac{(1+g_1)}{(k-g_1)}\right)\left(1 - \left(\frac{(1+g_1)}{(1+k)}\right)^5\right).$$
(31)

Note that this outcome for Stage 1 is identical to Equation 22, above.

Stage 2 of Equation 24 is:

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$$S_2 = \sum_{t=1}^{5} \frac{D_5(1+g_2)^t}{(1+k)^t}(1/(1+k)^5).$$

The derived form of Stages 2 and 3 are obtained through application of the same procedures as above, and need not be reviewed. The derived result for Stage 2 is as follows:

$$S_2 = D_5\left(\frac{(1+g_2)}{(k-g_2)}\right)\left(1-\left(\frac{(1+g_2)}{(1+k)}\right)^5\right)(1/(1+k)^5).$$

(32)

Stage 3 of Equation 25 is:

$$S_3 = \sum_{t=1}^{\infty} \frac{D_{10}(1+g_3)^t}{(1+k)^t}(1/(1+k)^{10}).$$

Similarly, the derived form of Stage 3 is:

$$S_3 = D_{10}\left(\frac{(1+g_3)}{(k-g_3)}\right)\left(1-\left(\frac{(1+g_3)}{(1+k)}\right)^\infty\right)(1/(1+k)^{10}).$$

(33)

Note that in Stage 3, the second term in the second bracket of the rhs vanishes as a result of, by assumption, $k>g$.

APPENDIX II

Capital Asset Pricing Model (CAPM)[50]

The Sharpe-Lintner Capital Asset Pricing Model (CAPM)—William Sharpe (1964) and John Lintner (1966)—is an extension of the one-period, mean-variance portfolio model of Markowitz (1959) and Tobin (1958), which in turn is built on the expected utility model of von Neumann and Morgenstern (1953). The Markowitz mean-variance analysis is concerned with how the investor should allocate wealth among the various assets available in the market, given that the investor is a one-period utility maximizer.

The derived CAPM shows how the valuation of a financial asset (price) is based upon two components: risk free returns and an *adjusted risk-based return.* Surrogates for risk free returns can be observed directly in capital markets, and include market returns on short- and intermediate-term debt. As a general rule, the cost rates and market returns on government debt obligations serve as appropriate surrogates.

The CAPM defines the market rate of return of asset j as a combination of the risk free return, R_f, and the product of a risk factor and the excess return above the risk free return, $\beta_{jm}(R_m - R_f)$. Excess return is determined as the difference between the return of the market as a whole, R_m, and the risk free return. The relevant risk factor is the well known market beta, which is defined as, the covariation of the market return of individual assets and equity markets as a whole

$$\beta_{jm} = \sigma_{jm}/\sigma^2_m \tag{1}$$

Start with an investment amount, I, where the share, α, is invested in asset j, and the share $(1-\alpha)$ is invested in the market portfolio, m. The rate of return on the portfolio is,

$$R_\alpha = \alpha R_j + (1-\alpha)R_m \tag{2}$$

The measure of variation I the portfolio returns is defined as,

$$\sigma_\alpha = [\alpha^2\sigma_j^2 + 2\alpha(1-\alpha)\sigma_{jm} + (1-\alpha)^2\sigma_m^2]^{(1/2)}. \tag{3}$$

If the portfolio share coefficient, α, is equal to zero, then the return on the portfolio is equal to R_m. This return point within rate of return – risk space is equivalent to the tangency point of market portfolio with the well-known market line.

Taking the relevant derivatives,

$$dR_\alpha/d\alpha = R_j - R_m \tag{4}$$

[50] As derived by and shown in *Investment Science*, by David Luenberger, 1998.

$$\sigma_a/d\alpha = [\alpha\sigma_j^2 + (1 - 2\alpha)\sigma_{jm} + (\alpha - 1)\sigma_m^2] / \sigma_a. \qquad (5)$$

For $\alpha=0$, the solution to (5) is,

$$\sigma_a/d\alpha = (\sigma_{jm} - \sigma_m^2) / \sigma_m. \qquad (6)$$

Defining a key relationship:

$$dR_a/d\sigma_a = (dR_a/d\alpha) / (d\sigma_a/d\alpha). \qquad (7)$$

For $\alpha=0$, the above result obtains,

$$dR_a/d\sigma_a = (R_j - R_m)\sigma_m / (\sigma_{jm} - \sigma_m^2). \qquad (8)$$

The result in (8) defines a rate of change with respect to σ_a, which must be equivalent to the slope of the capital market line. Therefore,

$$(R_j - R_m)\sigma_m / (\sigma_{jm} - \sigma_m^2) = (R_m - R_f)/\sigma_m. \qquad (9)$$

Now solving for R_j obtains the capital asset pricing model, stated in its well-known form,

$$R_j = R_f + [(R_m - R_f) / \sigma_m^2]\sigma_{jm} = R_f + \beta_{jm}(R_m - R_f) \qquad (10)$$

where β_{jm} is defined as above.

In summary, the CAPM can be shown in the context of the general and well known formulation (as model (referred to in footnote 27 of the report text), where the expected rate of return is a function of risk:

$$R_j = f[E(F)] = R_f + \beta(R_m - R_f).$$

In this formulation, R_j and $f(E(F)]$ are shown to be equivalent. As denoted in (3), R_f is the risk-free rate of return, R_M is the market rate of return and $(R_m - R_f)$ is the market price of risk, making β the risk premium attached to holding asset j in the (market) portfolio. The essential issue, then, is whether or not the relevant risk parameter (β) adequately captures all risks, as perceived by investors. As discussed below, recent empirical evidence suggests that it may not.

Issues Associated with CAPM

The results of the early studies of CAPM have suggested that a significant positive relationship existed between realized return and systematic risk, as measured by β, and that the relationship between risk and return appeared to be linear. However, the prediction of Sharpe-Lintner version of the model—that a portfolio or asset uncorrelated with the market should have an expected return equal to the risk-free rate of interest—have not done well. Evidence has suggested that the average return on "zero-beta" portfolios are higher than the risk-free rate.

The first tests of CAPM on individual stocks, within the context of the excess return form, appear to have been conducted by Lintner (1965) and Douglas (1968), who found that the estimated intercept is significantly different from the risk-free rate r_f and the estimate of β is statistically significant but takes a small value and the residual risk has effect on security returns. Thus, their results appear to contradict the CAPM model. However, the Douglas and Lintner studies appear to suffer from various statistical weaknesses that might explain their anomalous results. The measurement error that might be present in estimated betas in their studies could be explained by the fact that the assumptions of the regression model are not satisfied in practice.[51]

With regard to the test of CAPM in terms of stock portfolios, one classic test was performed by Fama and MacBeth (1973), who used a combined time series-cross sectional estimation to investigate whether the risk premia of the factors are non-zero. Their results showed that the beta coefficient was statistically insignificant and remained small for many sub-periods. In addition, the estimated intercept term was significantly greater than the risk-free rate, once again implying that the predictions of the CAPM might not hold.

Black, Jensen, and Scholes (1972) (Black *et al*) tested CAPM by using time series regression analysis. The results again showed that the intercept term is significantly different from zero and is time varying. They found that when $\beta > 1$, the intercept is negative and conversely when $\beta < 1$, the intercept is positive. Thus the findings of Black *et al* suggest the predictions of CAPM are not supported empirically. Stambaugh (1982) employed a slightly different methodology to test CAPM and found support for Black's version but not for the Sharpe-Lintner version. Gibbons (1982) has used a similar method as the one used by Stambaugh but instead was led to reject both standard and zero-beta CAPM formulations.

One of the principal arguments against the one-factor CAPM that uses only the market to explain excess returns is that it fails to capture the impact of other economic factors that influence investors' expected return (i.e., risk premium). Thus, another avenue of attack on the Sharpe-Lintner-Black CAPM formulations includes studies that have identified variables other than market β to explain a cross-section of expected returns. For example, Basu (1977) showed that the earnings-to-price (E/P) ratio has marginal explanatory power after controlling for β and expected returns appear to be positively related to E/P. Banz (1981) found that a stock's size (i.e., price times share) could help explain expected returns, which means that in the Sharpe-Lintner-Black framework, allowing for market β, expected returns on small stocks are too low and expected returns on large stocks are too high. Bhandari (1988) found that leverage is positively related to expected stock returns, and Fama and French (1992) found that higher book-to-market ratios are associated with higher expected returns in their tests that also include market β.

These anomalies of the Sharpe-Lintner-Black CAPM formulations are stylized facts that can be explained by a multifactor asset pricing model, of the type considered by Merton (1973) and Ross (1976). For example, Ball (1978) argued that E/P is a catch-all proxy for omitted factors in asset pricing tests and one can expect it to have explanatory power when an asset pricing model is expanded to include multiple factors but all relevant factors are not included in the estimated model. Chan and

[51] The violations of the standard model assumptions are that the error terms are not normally distributed, not independently distributed and may be correlated with the excess market return (i.e., the explanatory variable in the regression) perhaps due to omitted variables.

Chen (1991) argued that the "stock size" effect is due to the fact that small stocks include depressed firms whose performance is sensitive to business conditions.[52] Fama and French (1992) have shown that since leverage and book-to-market equity are also largely driven by market value of equity, they may also be used as proxies for risk factors that are related to market judgments about the relative prospects of firms. One can expect when asset pricing models allow for multiple factors and, at least in theory, when all relevant factors are included in the asset pricing tests, the anomalies found in earlier work would be resolved.

An alternative approach, as shown in Chen, Roll, and Ross (1986), is to look for economic variables that are correlated with stock returns and then to test whether the loading of these economic factors describe the cross section of expected returns. This approach provides insight into how the factors relate to uncertainties about consumption and portfolio opportunities that are of concern to an investor. They examined a range of business condition variables that might be related to return because they are related to shocks to expected future cash flows or discount rates. The most powerful variables are the growth rate of industrial production and the difference between the return on long-term, low-grade corporate bonds and long-term government bonds. The unexpected inflation rate and the difference between the return on long and short government bonds are found to be less significant.

Merton (1973) has constructed a generalized inter-temporal asset pricing model in which factors other than market uncertainty are priced. In Merton's formulation, individuals are solving a lifetime consumption decision in a multi-period setting. He has shown that expected return on assets depends not only on the covariance of the asset with the market but also with the covariance of the asset with changes in the investment opportunity set. Therefore, Merton's formulation can be interpreted as another form of arbitrage pricing theory model. Fama and French (1992) demonstrated that two variables—size and book-to-market-equity—combine to capture the cross-sectional variation in average stock return associated with market beta, size, leverage, book-to-market ratio, and earning-to-price ratio.

In addition to the theoretical problems associated with the application of the CAPM to estimating risk premia, there are also statistical issues to be addressed. The problems of estimating and forecasting systematic risk, (i.e., beta) in the CAPM have been studied by several authors such as Lam (1999), Lally (1998), Bowie and Bradfield (1998), Boabang (1996), Draper and Paudyal (1995), Murray (1995), and Bartholdy and Riding (1994). The classical estimator for β is the well-known ordinary least squares (OLS) estimator, but several authors have shown that this estimator suffers from several deficiencies. For example, it has a mean reversion tendency, it is inefficient when return distributions are non-normal, and has significant bias problems when shares are thinly traded.

Several alternatives to OLS have been proposed in the literature. Included among these are Vasicek (1973) and Blume (1973) who both proposed estimators to improve the mean reversion tendency of the OLS estimator of β, Chan and Lakonishok (1992) proposed robust estimators to ensure more efficient estimation of β, and Scholes and

[52] The presence of depressed firms or firms highly sensitive to the business cycle introduces what is known as a martingale effect in expected returns.

Williams (1977) proposed estimators to deal with the bias problem when shares are infrequently traded. A host of empirical studies have been carried out in order to evaluate the performance of the estimators under various conditions including studies by Draper and Paudyal (1995), Murray (1995), Boabang (1996), and Lally (1998). Of the above-mentioned estimators, the Vasicek-estimator and the robust estimators seem to perform well over a wide range of empirical studies.

APPENDIX III

ESTIMATES OF COST OF EQUITY: U.S. ELECTRIC UTILITIES (U.S. sample 1)

CAPITAL ASSET PRICING MODEL

Electric Utilities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	Ticker	2006	5 Year Average, 2006 Ending	2006	5 Year Average, 2006 Ending
Hawaiian Elec.	HE	0.70	0.63	0.55	0.45
Empire Dist. Elec.	EDE	0.85	0.65	0.78	0.48
MGE Energy	MGEE	0.85	0.61	0.78	0.42
Otter Tail Corp.	OTTR	0.75	0.58	0.63	0.37
CH Energy Group	CHG	0.85	0.76	0.78	0.64
Energy East Corp.	EAS	0.85	0.77	0.78	0.66
Florida Public Utilities	FPU	0.55	0.60	0.33	0.40
SCANA Corp.	SCG	0.75	0.55	0.63	0.33
UIL Holdings	UIL	0.90	0.75	0.85	0.63
G't Plains Energy	GXP	0.85	0.78	0.78	0.67
Vectren Corp.	VVC	0.90	0.77	0.85	0.66
	Average	0.80	0.64	0.65	0.47
	Standard Deviation	0.10	0.08	0.16	0.12
	Weighted Average:	0.81	0.68	0.72	0.53

MARKET INPUTS: AVERAGE YIELDS & OVERALL RETURNS

	1-Year Gov't Debt Interest Rates (%)	10-Year Gov't Debt Interest Rates (%)	1- to 10-Year Spread in Debt Rates (%)	S&P500 Total Return (%)	Chain-Weighted Rates of Inflation (%)
1950s	2.62	3.22	0.60		2.60
1960s	4.40	4.67	0.28		2.62
1970s	7.00	7.50	0.50	7.92	6.82
1980s	9.74	10.60	0.85	18.23	4.44
1990s	5.36	6.66	1.30	18.99	2.14
2000s	3.32	4.73	1.41	2.45	1.83
60s, 70s, 90s	5.58	6.28	0.74		
Overall	5.40	6.23	0.83	12.80	3.57

VARIATION IN YIELDS AND RETURNS (%)

	1-Year	10-Year	1- to 10-Year Spread	S&P500 Total Return
1950s	1.07	0.63	0.51	
1960s	1.32	0.91	0.46	
1970s	1.75	0.99	1.02	20.36
1980s	2.70	2.16	1.02	13.07
1990s	1.21	1.00	0.96	14.16
2000s	1.75	0.67	1.23	17.73
60s, 70s, 90s	1.43	0.97	0.81	
Overall	1.96	1.53	0.87	16.33

CAPM ESTIMATES: MID-SIZED ELECTRIC UTILITIES

	Equity Capital, Unadjusted	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	9.36%	3.96%	0.79	10.84%	3.96%
High	13.25%	5.49%	0.84	14.76%	5.49%
Weighted Average	11.28%	4.73%	0.81	12.80%	4.73%
			U.S. Equity Market Risk Premia:	8.07%	

ESTIMATES OF COST OF EQUITY: U.S. ELECTRIC UTILITIES (U.S. sample 1)

DISCOUNTED CASH FLOW

Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend Rate	Average Market Price Per Share, April - May '07	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
Hawaiian Elec.	HE	1.24	$1.26	$25.25	4.99%	3.18%	8.17%
Empire Dist. Elec.	EDE	1.28	$1.31	$23.98	5.45%	4.25%	9.71%
MGE Energy	MGEE	1.41	$1.45	$34.84	4.16%	5.40%	9.55%
Otter Tail Corp.	OTTR	1.17	$1.22	$33.31	3.65%	7.75%	11.40%
CH Energy Group	CHG	2.16	$2.17	$47.67	4.55%	0.93%	5.48%
Energy East Corp.	EAS	1.21	$1.22	$24.20	5.04%	1.43%	6.47%
Florida Public Utilities	FPU	0.43	$0.45	$12.60	3.55%	7.97%	11.52%
SCANA Corp.	SCG	1.56	$1.62	$42.96	3.76%	7.12%	10.88%
UIL Holdings	UIL	1.73	$1.74	$33.48	5.19%	0.68%	5.87%
G't Plains Energy	GXP	1.66	$1.74	$31.66	5.49%	9.57%	15.07%
Vectren Corp.	VVC	1.27	$1.34	$28.86	4.66%	11.66%	16.31%

DCF ESTIMATES, MID-SIZED ELECTRIC UTILITIES

	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	4.59%	5.45%	10.04%
S. D.	0.72%	3.68%	3.52%
Range			
Low	4.23%	3.61%	8.28%
High	4.95%	7.29%	11.80%
Weighted Average	4.66%	5.66%	10.32%

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HISTORICAL MARKET RETURNS, AVERAGE PER ANNUM

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006
Hawaiian Elec.	11.23%	10.19%	12.46%	11.78%	11.14%
Empire Dist. Elec.	8.32%	9.05%	9.29%	9.59%	9.11%
MGE Energy	12.59%	13.21%	12.83%	13.08%	11.29%
Otter Tail Corp.	16.90%	13.65%	11.84%	11.58%	11.53%
CH Energy Group	13.70%	10.72%	10.74%	10.03%	10.03%
Energy East Corp.	19.66%	17.09%	17.80%	16.92%	14.83%
Florida Public Utilities	17.71%	17.34%	17.85%	17.59%	16.00%
SCANA Corp.	9.47%	8.96%	9.39%	10.39%	10.97%
UIL Holdings	15.32%	10.58%	14.28%	13.93%	14.62%
G't Plains Energy	1.78%	6.49%	8.08%	7.52%	7.00%
Vectren Corp.	13.21%	9.38%	10.30%	11.11%	9.95%
Average	12.72%	11.51%	12.26%	12.14%	11.50%
Weighted Average	12.02%	11.00%	11.91%	11.86%	11.24%
			Across Years,	**Average:**	12.03%
				Weighted:	11.61%

HISTORICAL MARKET RETURNS, 5-YEAR AVERAGES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2002 - 2005	2003 - 2006
Hawaiian Elec.	11.23%	8.99%	15.39%	16.55%	13.28%
Empire Dist. Elec.	8.32%	5.46%	3.58%	5.37%	8.59%
MGE Energy	12.59%	12.56%	14.95%	17.77%	11.34%
Otter Tail Corp.	16.90%	12.73%	10.20%	9.76%	5.37%
CH Energy Group	13.70%	8.79%	9.55%	11.58%	7.91%
Energy East Corp.	19.66%	3.92%	4.27%	9.44%	9.36%
Florida Public Utilities	17.71%	12.62%	11.62%	16.03%	15.32%
SCANA Corp.	9.47%	6.01%	8.21%	6.37%	12.22%
UIL Holdings	15.32%	1.20%	8.24%	9.52%	11.29%
G't Plains Energy	1.78%	6.04%	11.42%	10.72%	10.06%
Vectren Corp.	13.21%	9.38%	10.30%	11.11%	9.33%
Average	12.72%	7.79%	9.79%	11.29%	10.37%
Weighted Average	12.02%	6.72%	9.21%	10.26%	10.47%
			Across Years,	**Average:**	10.39%
				Weighted:	9.74%

HISTORICAL MARKET RETURNS, CUMULATIVE

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006
Hawaiian Elec.	10.62%	9.65%	11.86%	11.25%	10.65%
Empire Dist. Elec.	7.47%	8.32%	8.67%	9.03%	8.61%
MGE Energy	12.01%	12.71%	12.41%	12.71%	10.83%
Otter Tail Corp.	16.59%	13.14%	11.32%	11.12%	11.13%
CH Energy Group	12.67%	9.67%	9.84%	9.23%	9.32%
Energy East Corp.	15.50%	13.54%	14.72%	14.21%	12.31%
Florida Public Utilities	16.57%	16.39%	17.03%	16.87%	15.27%
SCANA Corp.	8.42%	8.08%	8.63%	9.69%	10.33%
UIL Holdings	13.61%	8.64%	12.24%	12.15%	13.01%
G't Plains Energy	1.53%	5.81%	7.41%	6.93%	6.47%
Vectren Corp.	5.09%	4.52%	5.70%	6.74%	6.45%
Average	10.91%	10.04%	10.89%	10.90%	10.40%
Weighted Average	9.75%	9.20%	10.25%	10.36%	9.91%
			Across Years,	**Average:**	10.63%
				Weighted:	9.89%

ESTIMATES OF COST OF EQUITY: U.S. ELECTRIC UTILITIES (U.S. sample 1)

RISK PREMIUM

Timeframes	S&P 500 minus Intermediate Term Debt: Average Per Annum	S&P 500 minus Intermediate Term Debt: Geometric	S&P 500 minus Short Term Debt: Average Per Annum	S&P 500 minus Short Term Debt: Geometric	GDP Inflation
1950s	18.2%	16.6%	19.0%	17.4%	2.6%
1960s	4.2%	3.2%	4.8%	3.8%	2.6%
1970s	0.4%	-1.3%	1.2%	-0.7%	6.8%
1980s	8.2%	7.4%	9.3%	8.4%	4.4%
1990s	12.7%	11.8%	14.1%	13.2%	2.1%
2000s	-1.7%	0.0%	-0.6%	0.0%	1.8%
1950-Forward	7.5%				
Average, 50s-90s	8.7%	7.5%	9.7%	8.4%	3.7%
'50s, '60s, '80s, '90s	10.8%	9.8%	11.8%	10.7%	2.5%
'70s, '80s	4.3%	3.0%	5.2%	3.9%	5.6%
2000s	-1.7%	0.0%	-0.6%	0.0%	1.8%

Timeframes	Mid-Cap Size Premia, Differences From Market Index: Average	Mid-Cap: S.D	Small-Cap Size Premia, Differences From Market Index: Average	Small-Cap: S.D.	Micro-Cap Size Premia, Differences From Market Returns: Average	Micro-Cap: S.D.	1-Year Treasury Yields	1-Year 10-Year Spread
1950s	1.8%	2.1%	2.3%	2.9%	3.6%	4.3%	2.6%	0.6%
1960s	3.0%	3.3%	4.5%	6.5%	8.3%	10.7%	4.4%	0.3%
1970s	3.4%	5.5%	4.6%	9.8%	5.6%	13.8%	7.0%	0.5%
1980s	2.2%	4.2%	3.6%	8.0%	2.4%	11.3%	9.7%	0.9%
1990s	-1.0%	4.2%	-1.6%	5.3%	-1.5%	8.1%	5.4%	1.3%
2000s	3.2%	5.3%	5.9%	6.9%	11.3%	11.2%	3.3%	1.4%
Average, 50s-90s	1.9%	3.8%	2.7%	6.5%	3.7%	11.0%	6.6%	0.7%
'50s, '60s, '80s, '90s	1.5%	3.4%	2.2%	5.7%	3.5%	7.7%	4.1%	0.7%
'70s, '80s	2.8%	4.8%	4.1%	8.9%	4.0%	12.5%	8.4%	0.7%
2000s	3.2%	5.3%	5.9%	6.9%	11.3%	11.2%	3.3%	1.4%
S. D. Across Decades	1.6%		2.6%		4.5%		2.6%	0.5%

Equity Market Return

Cost Rate Components	Market Return Requirements: Lower Bound	Market Return Requirements: Upper Bound
1-Year Treasuries	2.0%	4.6%
1-Yr - 10-Yr Spread	1.2%	1.6%
Equity - T. Debt Risk Premia	7.5%	
Expected Overall Market Return	11.4%	13.0%

Cost Rate Adjustments, Small-Sized Equities

Adjustment Component	Lower Bound	Upper Bound
Diversifiable Risks	-1.6%	-1.3%
Small Capitalization Equities	1.2%	1.6%

Cost of Capital, Small-Size

	Lower Bound
w/o issuance Costs	10.97%
Average:	12.07%

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ESTIMATES OF COST OF EQUITY: U.S. ELECTRIC UTILITIES (U.S. sample 1)

SELECTION SCREEN 1

Company	Ticker	06 Market Cap ($M)	2006 Year End Beta	Average Beta 2002-2005	Standard Deviation, Beta 2002-2006	2006 Stock Price	2006 Financial Results: Revenues (M$)	2006 Financial Results: Operating Margins (M$)	2006 Financial Results: Total Assets (M$)	2006 Financial Results: Assets/ Revenue
Black Hills	BKH	1,163	1.10	0.94	0.11	34.85	657	37.56	2,245	3.42
Hawaiian Elec.	HE	2,203	0.70	0.65	0.07	27.04	2,461	15.90	9,891	4.02
PNM Resources	PNM	2,053	0.95	0.86	0.12	26.79	2,472	16.01	6,166	2.49
Cleco Corp.	CNL	1,356	1.35	1.09	0.15	23.55	1,001	19.33	2,461	2.46
Empire Dist. Elec.	EDE	679	0.85	0.69	0.09	22.44	413	32.60	1,316	3.18
MGE Energy	MGEE	686	0.85	0.64	0.09	32.70	508	21.74	982	1.94
OGE Energy	OGE	3,055	0.75	0.70	0.07	33.50	4,006	15.33	4,902	1.22
Otter Tail Corp.	OTTR	865	0.75	0.58	0.05	29.32	1,105	13.37	1,259	1.14
Cen. Vermont Pub. Serv.	CV	210	0.85	0.54	0.11	20.77	326	14.37	501	1.54
CH Energy Group	CHG	771	0.85	0.79	0.06	48.94	993	11.17	1,461	1.47
Energy East Corp.	EAS	3,592	0.85	0.80	0.08	24.28	5,231	21.44	11,562	2.21
Florida Public Utilities	FPU	82	0.55	0.60	0.06	13.58	134	15.55	181	1.35
NSTAR	NST	3,279	0.75	0.71	0.06	30.70	3,578	23.96	7,769	2.17
SCANA Corp.	SCG	4,094	0.75	0.58	0.10	36.23	3,885	22.96	8,996	2.32
UIL Holdings	UIL	866	0.90	0.79	0.10	34.83	846	17.02	1,631	1.93
UNITIL Corp.	UTL	140	0.45	0.41	0.03	24.84	261	17.42	483	1.85
G't Plains Energy	GXP	2,382	0.85	0.81	0.09	29.64	2,675	15.69	4,336	1.62
DPL Inc.	DPL	3,066	0.90	0.90	0.07	27.13	1,394	30.97	3,612	2.59
Vectren Corp.	VVC	2,073	0.90	0.79	0.05	27.24	2,042	19.03	4,092	2.00
Pinnacle West Capital	PNW	4,338	1.00	0.86	0.12	43.40	3,402	29.27	11,456	3.37
Average		1,848	0.85	0.74	0.08		1,869	20.53	4,265	2.21
Standard Deviation			0.19	0.16						0.79

ESTIMATES OF COST OF EQUITY: U.S. ELECTRIC UTILITIES (U.S. sample 1)

SELECTION SCREEN 2

		Equity Participation in Total Capital					Measures of Market Risk				Measures of Business and Financial Risk			
											Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share
Company	Ticker	1997	2001	2004	2006	Average	2006 Beta	*Average* Beta, 2002 - 2005	*S.D.,* CAPM Beta	Annual *Variation In* Market Return (%)	5 Year	5 Year	10 Year	10 Year
Black Hills	BKH	56%	55%	50%	56%	54%	1.10	0.94	0.11	6.27	0.25	0.12	0.56	0.27
Hawaiian Elec.	HE	44%	42%	51%	49%	46%	0.70	0.65	0.07	3.96	0.13	0.09	0.12	0.08
PNM Resources	PNM	53%	51%	52%	49%	51%	0.95	0.86	0.12	5.54	0.27	0.20	0.44	0.29
Cleco Corp.	CNL	49%	42%	53%	58%	51%	1.35	1.09	0.15	3.20	0.10	0.07	0.16	0.12
Empire Dist. Elec.	EDE	49%	43%	49%	50%	48%	0.85	0.69	0.09	2.05	0.24	0.21	0.29	0.25
MGE Energy	MGEE	58%	58%	63%	61%	60%	0.85	0.64	0.09	5.74	0.18	0.10	0.20	0.12
OGE Energy	OGE	52%	41%	47%	54%	49%	0.75	0.70	0.07	4.22	0.37	0.20	0.32	0.18
Otter Tail Corp.	OTTR	48%	53%	61%	64%	57%	0.75	0.58	0.05	4.62	0.14	0.09	0.18	0.12
Cen. Vermont Pub. Serv.	CV	58%	48%	60%	57%	56%	0.85	0.54	0.11	4.05	0.63	0.54	0.54	0.50
CH Energy Group	CHG	53%	65%	59%	59%	59%	0.85	0.79	0.06	5.22	0.28	0.11	0.29	0.10
Energy East Corp.	EAS	53%	38%	41%	43%	44%	0.85	0.80	0.08	3.93	0.14	0.09	0.26	0.15
Florida Public Utilities	FPU	52%	36%	45%	48%	45%	0.55	0.60	0.06	2.78	0.13	0.22	0.10	0.18
NSTAR	NST	46%	39%	40%	40%	41%	0.75	0.71	0.06	4.59	0.09	0.05	0.20	0.12
SCANA Corp.	SCG	48%	55%	42%	43%	47%	0.75	0.58	0.10	3.98	0.23	0.10	0.35	0.16
UIL Holdings	UIL	38%	50%	53%	53%	48%	0.90	0.79	0.10	4.16	0.29	0.19	0.46	0.24
UNITIL Corp.	UTL	50%	40%	45%	41%	44%	0.45	0.41	0.03	2.00	0.14	0.10	0.17	0.11
G't Plains Energy	GXP	43%	45%	53%	67%	52%	0.85	0.81	0.09	2.79	0.32	0.15	0.37	0.19
DPL Inc.	DPL	56%	24%	33%	31%	36%	0.90	0.90	0.07	4.30	0.41	0.36	0.34	0.27
Vectren Corp.	VVC	N/A	46%	52%	49%	49%	0.90	0.79	0.05	2.63	0.16	0.10	0.24	0.17
Pinnacle West Capital	PNW	46%	48%	53%	52%	50%	1.00	0.86	0.12	4.05	0.34	0.13	0.45	0.16
Average		50%	46%	50%	51%	49%	85%	74%	8%	4.00	24%	16%	30%	19%
Standard Deviation						6%	0.19	0.16	0.03	1.17	0.13	0.11	0.14	0.10

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APPENDIX IV

ESTIMATES OF COST OF EQUITY: U.S. GAS UTILITIES (U.S. sample 2)

CAPITAL ASSET PRICING MODEL

Electric Utilities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	Ticker	2006	5 Year Average, 2006 Ending	2006	5 Year Average, 2006 Ending
Atmos Energy	ATO	0.80	0.67	0.70	0.51
EnergySouth Inc	ENSI	0.65	0.53	0.48	0.30
Laclede Group	LG	0.90	0.71	0.85	0.57
New Jersey Resource	NJR	0.80	0.71	0.70	0.57
Northwest Nat. Gas	NWN	0.80	0.66	0.70	0.49
Piedmont Natural Gas	PNY	0.80	0.73	0.70	0.60
Southwest Gas	SWX	0.85	0.76	0.78	0.64
WGL Holdings Inc.	WGL	0.85	0.73	0.78	0.60
Average		0.81	0.67	0.69	0.50
Standard Deviation		0.07	0.07	0.12	0.11
Weighted Average:		0.82	0.70	0.73	0.56

MARKET INPUTS: AVERAGE YIELDS AND OVERALL RETURNS

	1-Year Gov't Debt Interest Rates (%)	10-Year Gov't Debt Interest Rates (%)	1- to 10-Year Spread in Debt Rates (%)	S&P500 Total Return (%)	Chain-Weighted Rates of Inflation (%)
1950s	2.62	3.22	0.60		2.60
1960s	4.40	4.67	0.28		2.62
1970s	7.00	7.50	0.50	7.92	6.82
1980s	9.74	10.60	0.85	18.23	4.44
1990s	5.36	6.66	1.30	18.99	2.14
2000s	3.32	4.73	1.41	2.45	1.83
60s, 70s, 90s	5.58	6.28	0.74		
Overall	5.40	6.23	0.83	12.80	3.57

VARIATION IN YIELDS AND RETURNS (%)

	1-Year	10-Year	1- to 10-Year Spread	S&P500 Total Return
1950s	1.07	0.63	0.51	
1960s	1.32	0.91	0.46	
1970s	1.75	0.99	1.02	20.36
1980s	2.70	2.16	1.02	13.07
1990s	1.21	1.00	0.96	14.16
2000s	1.75	0.67	1.23	17.73
60s, 70s, 90s	1.43	0.97	0.81	
Overall	1.96	1.53	0.87	16.33

CAPM ESTIMATES: MOEST-SIZED GAS DISTRIBUTION UTILITIES

	of Equity Capital	Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	9.46%	3.96%	0.80	10.84%	3.96%
High	13.23%	5.49%	0.84	14.76%	5.49%
Weighted Average	11.32%	4.73%	0.82	12.80%	4.73%

U.S. Equity Market Risk Premia: 8.07%

ESTIMATES OF COST OF EQUITY: U.S. GAS UTILITIES (U.S. sample 2)

DISCOUNTED CASH FLOW

Electric Utility	Ticker	Dividend Per Share	Effective Year Forward Dividend Rate	Average Market Price Per Share, April - May '07	Adjusted Dividend Yield	Expected Growth	Single Stage DCF Estimates of Cost of Equity Capital
Atmos Energy	ATO	1.28	$1.33	$40.67	3.26%	7.09%	10.34%
EnergySouth Inc	ENSI	0.96	$1.00	$44.11	2.28%	9.37%	11.65%
Laclede Group	LG	1.45	$1.48	$31.28	4.72%	3.54%	8.26%
New Jersey Resources	NJR	1.52	$1.59	$54.24	2.94%	9.64%	12.58%
Northwest Nat. Gas	NWN	1.44	$1.51	$50.32	3.00%	9.61%	12.61%
Piedmont Natural Gas	PNY	0.99	$1.03	$26.47	3.88%	7.29%	11.17%
Southwest Gas	SWX	0.86	$0.90	$37.92	2.37%	8.58%	10.94%
WGL Holdings Inc.	WGL	1.35	$1.39	$34.56	4.02%	5.59%	9.61%

DCF ESTIMATES, MID-SIZED ELECTRIC UTILITIES

	Adjusted Dividend Yield	Expected Growth	Unadjusted Cost Rate
Average	3.31%	7.59%	10.90%
S. D.	0.85%	2.18%	1.48%
Range			
Low	2.88%	6.50%	10.15%
High	3.73%	8.68%	11.64%
Weighted Average	3.38%	7.49%	10.86%

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ESTIMATES OF COST OF EQUITY: U.S. GAS UTILITIES (U.S. sample 2)

HISTORICAL MARKET RETURNS, AVERAGE PER ANNUM

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006
Atmos Energy	4.49%	5.38%	6.67%	7.73%	7.15%
EnergySouth Inc	12.79%	12.83%	15.75%	15.87%	15.62%
Laclede Group	6.74%	7.37%	9.34%	9.74%	9.66%
New Jersey Resources	13.86%	13.63%	14.62%	15.00%	13.86%
Northwest Nat. Gas	7.47%	6.91%	8.31%	9.74%	9.51%
Piedmont Natural Gas	12.45%	12.18%	13.07%	13.50%	12.92%
Southwest Gas	9.99%	7.92%	8.67%	9.13%	10.95%
WGL Holdings Inc.	7.39%	6.47%	7.72%	8.75%	7.78%
Average	9.40%	9.09%	10.52%	11.19%	10.93%
Weighted Average	8.92%	8.62%	9.82%	10.57%	10.25%
			Across Years,	**Average:**	10.22%
				Weighted:	9.63%

HISTORICAL MARKET RETURNS, 5-YEAR AVERAGES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2002 - 2005	2003 - 2006
Atmos Energy	4.49%	2.00%	5.25%	12.89%	8.66%
EnergySouth Inc	12.79%	9.55%	17.65%	21.48%	20.77%
Laclede Group	6.74%	6.40%	10.56%	14.34%	11.98%
New Jersey Resources	13.86%	11.51%	13.47%	15.20%	14.13%
Northwest Nat. Gas	7.47%	5.84%	10.23%	15.20%	13.60%
Piedmont Natural Gas	12.45%	8.03%	10.36%	15.31%	12.42%
Southwest Gas	9.99%	5.18%	2.48%	9.86%	11.56%
WGL Holdings Inc.	7.39%	4.11%	7.07%	8.77%	6.66%
Average	9.40%	6.58%	9.63%	14.13%	12.47%
Weighted Average	8.92%	5.89%	8.28%	13.16%	11.14%
			Across Years,	**Average:**	10.44%
				Weighted:	9.48%

HISTORICAL MARKET RETURNS, CUMULATIVE

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006
Atmos Energy	2.98%	4.09%	5.51%	6.67%	6.20%
EnergySouth Inc	11.76%	11.97%	14.79%	15.03%	14.87%
Laclede Group	6.32%	7.01%	8.93%	9.38%	9.34%
New Jersey Resources	13.73%	13.52%	14.50%	14.89%	13.71%
Northwest Nat. Gas	6.94%	6.46%	7.87%	9.29%	9.10%
Piedmont Natural Gas	11.56%	11.43%	12.40%	12.91%	12.38%
Southwest Gas	8.23%	6.38%	7.32%	7.94%	9.76%
WGL Holdings Inc.	7.18%	6.28%	7.51%	8.53%	7.56%
Average	8.59%	8.39%	9.85%	10.58%	10.37%
Weighted Average	8.03%	7.86%	9.12%	9.93%	9.65%
			Across Years,	**Average:**	9.56%
				Weighted:	8.92%

ESTIMATES OF COST OF EQUITY: U.S. GAS UTILITIES (U.S. sample 2)

RISK PREMIUM

Timeframes	S&P 500 minus Intermediate Term Debt		S&P 500 minus Short Term Debt		GDP Inflation
	Average Per Annum	Geometric	Average Per Annum	Geometric	
1950s	18.2%	16.6%	19.0%	17.4%	2.8%
1960s	4.2%	3.2%	4.8%	3.8%	2.6%
1970s	0.4%	-1.3%	1.2%	-0.7%	6.8%
1980s	8.2%	7.4%	9.3%	8.4%	4.4%
1990s	12.7%	11.6%	14.1%	13.2%	2.1%
2000s	-1.7%	0.0%	-0.6%	0.0%	1.8%
1950-Forward	7.5%				
Average, 50s-90s	8.7%	7.5%	9.7%	8.4%	3.7%
'50s, '60s, '80s, '90s	10.8%	9.8%	11.8%	10.7%	2.5%
'70s, '80s	4.3%	3.0%	5.2%	3.9%	5.6%
2000s	-1.7%	0.0%	-0.6%	0.0%	1.8%

Timeframes	Mid-Cap Size Premia, Differences From Market Index		Small-Cap Size Premia, Differences From Market Index		Micro-Cap Size Premia, Differences From Market Returns		1-Year Treasury Yields	1-Year 10-Year Spread
	Average	S.D	Average	S.D.	Average	S.D.		
1950s	1.8%	2.1%	2.3%	2.9%	3.6%	4.3%	2.6%	0.6%
1960s	3.0%	3.3%	4.5%	6.5%	8.3%	10.7%	4.4%	0.3%
1970s	3.4%	5.5%	4.6%	9.8%	5.6%	13.6%	7.0%	0.5%
1980s	2.2%	4.2%	3.6%	8.0%	2.4%	11.3%	9.7%	0.9%
1990s	-1.0%	4.2%	-1.6%	5.3%	-1.5%	8.1%	5.4%	1.3%
2000s	3.2%	5.3%	5.9%	6.9%	11.3%	11.2%	3.3%	1.4%
Average, 50s-90s	1.9%	3.8%	2.7%	6.5%	3.7%	11.0%	6.6%	0.7%
'50s, '60s, '80s, '90s	1.5%	3.4%	2.2%	5.7%	3.5%	7.7%	4.1%	0.7%
'70s, '80s	2.8%	4.8%	4.1%	8.9%	4.0%	12.5%	8.4%	0.7%
2000s	3.2%	5.3%	5.9%	6.9%	11.3%	11.2%	3.3%	1.4%
S. D. Across Decades	1.6%		2.6%		4.5%		2.6%	0.5%

Equity Market Return

Cost Rate Components	Market Return Requirements	
	Lower Bound	Upper Bound
1-Year Treasuries	2.0%	4.6%
1-Yr - 10-Yr Spread	1.2%	1.6%
Equity - T. Debt Risk Premia	7.5%	
Expected Overall Market Return	11.4%	13.0%

Cost Rate Adjustments, Small-Sized Equities

Adjustment Component	Lower Bound	Upper Bound
Diversifiable Risks	-1.6%	-1.3%
Small Capitalization Risk Premia	1.2%	1.6%

Cost of Capital, Small-Sized Equities

	Lower Bound	Upper Bound
w/o issuance Costs	11.02%	13.21%
Average:	12.12%	

ESTIMATES OF COST OF EQUITY: U.S. GAS UTILITIES (U.S. sample 2)

SELECTION SCREEN 1

Company	Ticker	06 Market Cap ($M)	2006 Year End Beta	Average Beta 2002-2005	Standard Deviation, Beta 2002-2006	2006 Stock Price	2006 Financial Results: Revenues (M$)	Operating Margins (M$)	Total Assets (M$)	Assets/ Revenue
AGL Resources	ATG	2,849	0.85	0.84	0.09	36.67	2,621	25.41	6,147	2.35
Atmos Energy	ATO	2,211	0.80	0.69	0.05	27.05	6,152	12.73	5,720	0.93
EnergySouth Inc	ENSI	244	0.65	0.54	0.05	30.65	136	36.62	263	1.93
Laclede Group	LG	688	0.90	0.74	0.09	32.23	1,998	6.72	1,570	0.79
New Jersey Resources	NJR	1,247	0.80	0.73	0.06	45.13	3,300	5.49	2,399	0.73
Nicor Inc.	GAS	1,931	1.05	1.06	0.11	43.00	2,960	15.02	4,090	1.38
Northwest Nat. Gas	NWN	1,015	0.80	0.68	0.06	37.25	1,013	20.13	1,957	1.93
Piedmont Natural Gas	PNY	1,837	0.80	0.75	0.04	24.62	1,925	14.08	2,734	1.42
South Jersey Inds.	SJI	856	0.70	0.59	0.09	29.17	931	18.96	1,573	1.69
Southwest Gas	SWX	1,318	0.85	0.78	0.06	31.56	2,025	18.67	3,485	1.72
WGL Holdings Inc.	WGL	1,466	0.85	0.75	0.07	29.99	2,638	11.20	2,791	1.06
Average		1,424	0.82	0.74	0.07	33.39	2,336	16.82	2,975	1.45
Standard Deviation			0.10	0.14						0.53

ESTIMATES OF COST OF EQUITY: U.S. GAS UTILITIES (U.S. sample 2)

SELECTION SCREEN 2

		Equity Participation in Total Capital					Measures of Market Risk				Measures of Business and Financial Risk			
											Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share
Company	Ticker	1997	2001	2004	2006	Average	2006 Beta	Average Beta, 2002 - 2005	S.D., CAPM Beta	Annual Variation In Market Return (%)	5 Year	5 Year	10 Year	10 Year
AGL Resources	ATG	49%	39%	46%	50%	46%	0.85	0.84	0.09	6.87	0.35	0.15	0.59	0.33
Atmos Energy	ATO	52%	46%	57%	43%	49%	0.80	0.69	0.05	2.86	0.20	0.12	0.36	0.24
EnergySouth Inc	ENSI	46%	44%	53%	61%	51%	0.65	0.54	0.05	6.58	0.18	0.11	0.27	0.20
Laclede Group	LG	62%	50%	48%	50%	53%	0.90	0.74	0.09	3.80	0.42	0.23	0.33	0.20
New Jersey Resources	NJR	49%	50%	60%	65%	56%	0.80	0.73	0.06	8.75	0.27	0.11	0.48	0.23
Nicor Inc.	GAS	57%	62%	60%	64%	61%	1.05	1.06	0.11	2.88	0.37	0.15	0.33	0.13
Northwest Nat. Gas	NWN	49%	53%	54%	54%	52%	0.80	0.68	0.06	4.98	0.29	0.15	0.34	0.19
Piedmont Natural Gas	PNY	52%	52%	56%	52%	53%	0.80	0.75	0.04	3.88	0.16	0.13	0.16	0.15
South Jersey Inds.	SJI	36%	36%	51%	55%	45%	0.70	0.59	0.09	6.26	0.48	0.29	0.52	0.40
Southwest Gas	SWX	32%	40%	36%	39%	37%	0.85	0.78	0.06	3.82	0.37	0.26	0.35	0.26
WGL Holdings Inc.	WGL	56%	56%	57%	60%	57%	0.85	0.75	0.07	2.32	0.44	0.23	0.34	0.19
Average		49%	48%	53%	54%	51%	0.82	0.74	0.07	4.82	0.32	0.18	0.37	0.23
Standard Deviation						7%	0.10	0.14	0.02	2.04	0.11	0.06	0.12	0.08

APPENDIX V

ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

CAPITAL ASSET PRICING MODEL

Electric Utilities		Adjusted CAPM Beta		Unadjusted Beta, as Inferred	
Company	Ticker	2006	5 Year Average, 2006 Ending	2006	5 Year Average, 2006 Ending
Great Southern Bancorp	GSBC	0.75	0.52	0.63	0.28
Steinway Musical	LVB	0.90	0.69	0.85	0.54
U S Lime & Minerals	USLM	0.70	0.56	0.55	0.34
Winmark Corp	WINA	0.60	0.63	0.40	0.45
CPI Corp.	CPY	0.85	0.72	0.78	0.58
Indep Bank Corp/MI	IBCP	0.80	0.64	0.70	0.46
Patriot Transportation Holdin	PATR	0.50	0.53	0.25	0.30
Vitran Corporation Inc	VTN.TO	0.70	0.66	0.55	0.49
Supreme Inds Inc.	STS	0.65	0.77	0.48	0.66
Farmers Capital Bank Corp.	FFKT	0.65	0.63	0.48	0.45
Alamo Group	ALG	0.65	0.54	0.48	0.31
Northwest Pipe Co	NWPX	0.75	0.52	0.63	0.28
Oil-Dri Corp of Amer	ODC	0.55	0.51	0.33	0.27
Samuel Manu-Tech Inc.	SMT.TO	0.60	0.59	0.40	0.39
Meadowbrook Ins Grou	MIG	0.60	0.80	0.40	0.70
Frisch's Restaurants	FRS	0.60	0.57	0.40	0.36
Sunlink Health Sys	SSY	0.80	0.59	0.70	0.39
Old Second Bancorp	OSBC	0.75	0.55	0.63	0.33
Village Super Market 'A'	VLGEA	0.60	0.62	0.40	0.43
Utah Medical Prods.	UTMD	0.55	0.59	0.33	0.39
	Average	0.72	0.61	0.59	0.42
	Standard Deviation	0.13	0.08	0.21	0.12
	Weighted Average:	0.70	0.61	0.55	0.42

MARKET INPUTS: AVERAGE YIELDS AND OVERALL RETURNS

	1-Year Gov't Debt Interest Rates (%)	10-Year Gov't Debt Interest Rates (%)	1- to 10-Year Spread in Debt Rates (%)	S&P500 Total Return (%)	Chain-Weighted Rates of Inflation (%)
1950s	2.62	3.22	0.60		2.60
1960s	4.40	4.67	0.28		2.62
1970s	7.00	7.50	0.50	7.92	6.82
1980s	9.74	10.60	0.85	18.23	4.44
1990s	5.36	6.66	1.30	18.99	2.14
2000s	3.32	4.73	1.41	2.45	1.83
60s, 70s, 90s	5.58	6.28	0.74		
Overall	5.40	6.23	0.83	12.80	3.57

VARIATION IN YIELDS AND RETURNS (%)

	1-Year	10-Year	1- to 10-Year Spread	S&P500 Total Return
1950s	1.07	0.63	0.51	
1960s	1.32	0.91	0.46	
1970s	1.75	0.99	1.02	20.36
1980s	2.70	2.16	1.02	13.07
1990s	1.21	1.00	0.96	14.16
2000s	1.75	0.67	1.23	17.73
60s, 70s, 90s	1.43	0.97	0.81	
Overall	1.96	1.53	0.87	16.33

CAPM ESTIMATES: COMPARABLE RISK NON-UTILITY COMPANIES

Market Cost of Equity Capital, Unadjusted		Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	10.09%	4.73%	0.66	12.80%	4.73%
High	10.60%	4.73%	0.73	12.80%	4.73%
Weighted Average	10.35%	4.73%	0.70	12.80%	4.73%
		U.S. Equity Market Risk Premia:		8.07%	

ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

HISTORICAL MARKET RETURNS, AVERAGE PER ANNUM

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006
Great Southern Bancorp	22.59%	21.38%	25.40%	23.30%	19.89%
Steinway Musical	0.35%	-1.62%	9.63%	7.54%	7.18%
U S Lime & Minerals	-9.17%	-7.42%	9.72%	23.61%	26.27%
Winmark Corp	5.33%	11.66%	18.76%	14.92%	14.32%
CPI Corp.	-1.98%	0.60%	-0.40%	1.83%	12.64%
Indep Bank Corp/MI	23.72%	25.05%	22.75%	21.52%	18.74%
Patriot Transportation Holdin	3.08%	2.99%	6.14%	12.05%	15.81%
Vitran Corporation Inc	6.06%	19.14%	26.53%	23.04%	21.82%
Supreme Inds Inc.	2.79%	1.83%	6.17%	7.79%	6.70%
Farmers Capital Bank Corp.	12.95%	10.78%	10.58%	9.23%	8.36%
Alamo Group	-0.39%	-1.31%	4.30%	6.67%	6.41%
Northwest Pipe Co	-1.68%	-5.09%	-0.96%	5.76%	6.68%
Oil-Dri Corp of Amer	-8.37%	-3.43%	6.59%	7.64%	8.11%
Samuel Manu-Tech Inc.	-8.62%	-6.21%	-0.78%	3.17%	5.12%
Meadowbrook Ins Grou	-30.56%	-22.06%	-11.08%	-8.59%	-1.02%
Frisch's Restaurants	7.84%	9.49%	13.84%	12.06%	10.24%
Sunlink Health Sys	0.00%	0.00%	0.00%	0.00%	0.00%
Old Second Bancorp	18.93%	19.58%	21.13%	20.43%	18.33%
Village Super Market 'A'	27.34%	21.35%	21.94%	23.42%	26.19%
Utah Medical Prods.	15.40%	18.67%	17.57%	16.06%	18.34%
Average	4.28%	5.77%	10.39%	11.57%	12.51%
Weighted Average	6.32%	7.81%	11.93%	12.94%	13.48%
			Across Years,	**Average:**	8.90%
				Weighted:	10.50%

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ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

HISTORICAL MARKET RETURNS, 5-YEAR AVERAGES

Company	1998 - 2002	1999 - 2003	2000 - 2004	2002 - 2005	2003 - 2006
Great Southern Bancorp	22.59%	17.52%	26.20%	32.82%	21.74%
Steinway Musical	0.35%	-7.82%	10.92%	12.88%	14.98%
U S Lime & Minerals	-9.17%	-8.72%	14.13%	39.91%	53.68%
Winmark Corp	5.33%	11.69%	31.29%	36.97%	30.92%
CPI Corp.	-1.98%	-3.03%	-7.48%	-0.78%	22.03%
Indep Bank Corp/MI	23.72%	22.64%	29.70%	33.21%	17.26%
Patriot Transportation Holdin	3.08%	-1.86%	7.90%	21.25%	33.81%
Vitran Corporation Inc	6.06%	17.08%	30.05%	35.90%	43.57%
Supreme Inds Inc.	2.79%	-6.83%	2.24%	13.73%	17.82%
Farmers Capital Bank Corp.	12.95%	1.11%	3.58%	4.37%	2.61%
Alamo Group	-0.39%	0.94%	16.58%	14.70%	12.32%
Northwest Pipe Co	-1.68%	-5.94%	3.78%	18.18%	17.88%
Oil-Dri Corp of Amer	-8.37%	-5.33%	9.51%	16.26%	24.01%
Samuel Manu-Tech Inc.	-8.62%	-7.40%	6.00%	15.89%	22.85%
Meadowbrook Ins Grou	-30.56%	-28.63%	-7.25%	6.12%	23.86%
Frisch's Restaurants	7.84%	11.45%	23.99%	24.34%	17.63%
Sunlink Health Sys	0.00%	0.00%	0.00%	0.00%	0.00%
Old Second Bancorp	18.93%	19.94%	26.76%	32.88%	24.43%
Village Super Market 'A'	27.34%	20.81%	20.49%	28.81%	37.12%
Utah Medical Prods.	15.40%	26.80%	29.46%	29.59%	27.57%
Average	4.28%	3.72%	13.89%	20.85%	23.30%
Weighted Average	6.32%	5.47%	15.62%	22.67%	23.37%
			Across Years,	**Average:**	13.21%
				Weighted:	14.69%

ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

HISTORICAL MARKET RETURNS, CUMULATIVE

Company	1998 - 2002	1998 - 2003	1998 - 2004	1998 - 2005	1998 - 2006
Great Southern Bancorp	18.94%	18.33%	22.35%	20.55%	17.06%
Steinway Musical	-1.18%	-2.97%	5.74%	4.05%	4.07%
U S Lime & Minerals	-9.50%	-7.78%	3.90%	14.17%	17.47%
Winmark Corp	-2.14%	4.28%	10.99%	7.82%	8.01%
CPI Corp.	-3.21%	-0.60%	-1.45%	0.73%	8.65%
Indep Bank Corp/MI	18.26%	20.40%	18.69%	17.96%	15.36%
Patriot Transportation Holdin	-0.14%	0.30%	3.51%	8.73%	12.34%
Vitran Corporation Inc	1.27%	11.92%	18.89%	16.15%	15.69%
Supreme Inds Inc.	-2.95%	-2.96%	1.43%	3.48%	2.86%
Farmers Capital Bank Corp.	10.84%	8.94%	9.00%	7.81%	7.07%
Alamo Group	-3.85%	-4.20%	0.93%	3.48%	3.57%
Northwest Pipe Co	-3.39%	-6.80%	-2.94%	2.72%	3.93%
Oil-Dri Corp of Amer	-9.31%	-4.81%	3.12%	4.54%	5.33%
Samuel Manu-Tech Inc.	*-10.78%*	-8.21%	-3.34%	0.39%	2.47%
Meadowbrook Ins Grou	-34.62%	-27.61%	-19.31%	-16.23%	-10.02%
Frisch's Restaurants	5.65%	7.58%	11.70%	10.11%	8.41%
Sunlink Health Sys	0.00%	0.00%	0.00%	0.00%	0.00%
Old Second Bancorp	16.03%	17.14%	18.96%	18.52%	16.49%
Village Super Market 'A'	23.69%	17.60%	18.70%	20.49%	23.30%
Utah Medical Prods.	11.91%	15.47%	14.81%	13.60%	15.96%
Average	1.28%	2.80%	6.78%	7.95%	8.90%
Weighted Average	3.13%	4.68%	8.29%	9.33%	9.87%
			Across Years,	**Average:**	5.54%
				Weighted:	7.06%

ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

RISK PREMIUM

Timeframes	S&P 500 minus Intermediate Term Debt: Average Per Annum	S&P 500 minus Intermediate Term Debt: Geometric	S&P 500 minus Short Term Debt: Average Per Annum	S&P 500 minus Short Term Debt: Geometric	GDP Inflation
1950s	18.2%	16.6%	19.0%	17.4%	2.6%
1960s	4.2%	3.2%	4.8%	3.8%	2.6%
1970s	0.4%	-1.3%	1.2%	-0.7%	6.8%
1980s	8.2%	7.4%	9.3%	8.4%	4.4%
1990s	12.7%	11.8%	14.1%	13.2%	2.1%
2000s	-1.7%	0.0%	-0.6%	0.0%	1.8%
1950-Forward	7.5%				
Average, 50s-90s	8.7%	7.5%	9.7%	8.4%	3.7%
'50s, '60s, '80s, '90s	10.8%	9.8%	11.8%	10.7%	2.5%
'70s, '80s	4.3%	3.0%	5.2%	3.9%	5.6%
2000s	-1.7%	0.0%	-0.6%	0.0%	1.8%

Timeframes	Mid-Cap Size Premia, Differences From Market Index: Average	Mid-Cap: S.D	Small-Cap Size Premia, Differences From Market Index: Average	Small-Cap: S.D.	Micro-Cap Size Premia, Differences From Market Returns: Average	Micro-Cap: S.D.	1-Year Treasury Yields	1-Year 10-Year Spread
1950s	1.8%	2.1%	2.3%	2.9%	3.6%	4.3%	2.6%	0.6%
1960s	3.0%	3.3%	4.5%	6.5%	8.3%	10.7%	4.4%	0.3%
1970s	3.4%	5.5%	4.6%	9.8%	5.6%	13.8%	7.0%	0.5%
1980s	2.2%	4.2%	3.6%	8.0%	2.4%	11.3%	9.7%	0.9%
1990s	-1.0%	4.2%	-1.6%	5.3%	-1.5%	8.1%	5.4%	1.3%
2000s	3.2%	5.3%	5.9%	6.9%	11.3%	11.2%	3.3%	1.4%
Average, 50s-90s	1.9%	3.8%	2.7%	6.5%	3.7%	11.0%	6.6%	0.7%
'50s, '60s, '80s, '90s	1.5%	3.4%	2.2%	5.7%	3.5%	7.7%	4.1%	0.7%
'70s, '80s	2.8%	4.8%	4.1%	8.9%	4.0%	12.5%	8.4%	0.7%
2000s	3.2%	5.3%	5.9%	6.9%	11.3%	11.2%	3.3%	1.4%
S. D. Across Decades	1.6%		2.6%		4.5%		2.6%	0.5%

Equity Market Return

Cost Rate Components	Market Return Requirements: Lower Bound	Market Return Requirements: Upper Bound
1-Year Treasuries	2.0%	4.6%
1-Yr - 10-Yr Spread	1.2%	1.6%
Equity - T. Debt Risk Premia	7.5%	
Expected Overall Market Return	11.4%	13.0%

Cost Rate Adjustments, Small-Sized Equities

Adjustment Component	Lower Bound	Upper Bound
Diversifiable Risks	-2.7%	-2.2%
Small Capitalization Equities	1.9%	3.9%

Cost of Capital, Small-Sized Equities

	Lower Bound	Upper Bound
w/o issuance Costs	10.69%	14.73%
Average:	12.71%	

ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

SELECTION SCREEN 1

Company	Ticker	06 Market Cap ($M)	2006 Year End Beta	Average Beta 2002-2005	Standard Deviation, Beta 2002-2006	2006 Stock Price	2006 Financial Results: Revenues (M$)	Operating Margins (M$)	Total Assets (M$)	Assets/ Revenue
Merchants Bancshares Inc.	MBVT	141	0.60	0.61	0.05	23.98			1,137	
Great Southern Bancorp	GSBC	389	0.75	0.53	0.10	28.43			2,240	
Steinway Musical	LVB	243	0.90	0.68	0.03	29.00	385	7.66	447	1.16
U S Lime & Minerals	USLM	188	0.70	0.58	0.05	30.24	119	26.26	154	1.30
NewBridge Bancorp	NBBC	146	0.80	0.76	0.09	17.35			988	
Winmark Corp	WINA	131	0.60	0.61	0.07	23.13	27	20.33	38	1.37
CPI Corp.	CPY	216	0.85	0.73	0.03	33.90	294	15.05	90	0.31
Indep Bank Corp/MI	IBCP	575	0.80	0.65	0.04	25.16			3,430	
Patriot Transportation Holdin	PATR	215	0.50	0.53	0.06	71.54	147	20.74	219	1.49
Vitran Corporation Inc	VTN.TO	297	0.70	0.69	0.09	22.15	514	7.80	358	0.70
Supreme Inds Inc.	STS	89	0.65	0.76	0.03	6.99	341	3.93	142	0.42
Farmers Capital Bank Corp.	FFKT	257	0.65	0.63	0.03	32.62			1,824	
Alamo Group	ALG	218	0.65	0.54	0.05	22.33	456	7.06	327	0.72
Northwest Pipe Co	NWPX	256	0.75	0.53	0.06	28.78	347	9.55	424	1.22
Oil-Dri Corp of Amer	ODC	101	0.55	0.51	0.03	14.89	205	7.58	140	0.68
Samuel Manu-Tech Inc.	SMT.TO	418	0.60	0.56	0.09	13.04	905	10.54	570	0.63
Meadowbrook Ins Grou	MIG	254	0.60	0.81	0.11	8.73			969	
Frisch's Restaurants	FRS	120	0.60	0.58	0.03	23.75	291	31.59	175	0.60
Sunlink Health Sys	SSY	70	0.80	0.64	0.14	9.52	136	20.75	74	0.55
NAPCO Security Systems Inc.	NSSC	153	0.80	0.48	0.05	7.66	70	15.41	72	1.03
Old Second Bancorp	OSBC	403	0.75	0.56	0.06	30.67			2,459	
Village Super Market 'A'	VLGEA	189	0.60	0.63	0.05	29.25	1,017	4.03	271	0.27
Utah Medical Prods.	UTMD	125	0.55	0.58	0.03	31.63	29	39.88	44	1.54
SL Inds. Inc.	SLI	93	0.95	0.84	0.03	16.55	177	7.73	107	0.60
Average		220	0.70	0.62	0.06		321	15	696	0.86
Standard Deviation			0.12	0.10						0.42

ESTIMATES OF COST EQUITY: U.S. Non-Utilities (U.S. sample 3)

SELECTION SCREEN 2

		Equity Participation in Total Capital					Measures of Market Risk				Measures of Business and Financial Risk			
											Variation in Earnings per share	CV in Earnings per Share	Variation in Earnings per share	CV in Earnings per Share
Company	Ticker	1997	2001	2004	2006	Average	2006 Beta	Average Beta, 2002 - 2005	S.D., CAPM Beta	Annual Variation In Market Returns (%)	5 Year	5 Year	10 Year	10 Year
Merchants Bancshares Inc.	MBVT	89%	97%	48%	42%	69%	0.60	0.61	0.05	5.18	0.10	0.06	0.22	0.13
Great Southern Bancorp	GSBC	28%	24%	36%	46%	33%	0.75	0.53	0.10	8.93	0.25	0.14	0.53	0.38
Steinway Musical	LVB	40%	37%	41%	48%	42%	0.90	0.68	0.03	5.12	0.80	0.64	0.61	0.41
U S Lime & Minerals	USLM	92%	49%	54%	55%	62%	0.70	0.58	0.05	8.39	0.74	0.71	0.63	0.82
NewBridge Bancorp	NBBC	100%	56%	49%	55%	65%	0.80	0.76	0.09	2.05	0.19	0.19	0.13	0.13
Winmark Corp	WINA	80%	98%	100%	56%	84%	0.60	0.61	0.07	6.86	0.13	0.23	0.16	0.30
CPI Corp.	CPY	63%	57%	57%	57%	59%	0.85	0.73	0.03	5.94	0.86	0.70	0.71	0.58
Indep Bank Corp/MI	IBCP	26%	36%	57%	61%	45%	0.80	0.65	0.04	7.56	0.22	0.13	0.53	0.44
Patriot Transportation Holdin	PATR	68%	61%	70%	66%	66%	0.50	0.53	0.06	16.26	0.54	0.27	0.63	0.39
Vitran Corporation Inc	VTN.TO	48%	55%	91%	65%	65%	0.70	0.69	0.09	6.81	0.20	0.16	0.34	0.35
Supreme Inds Inc.	STS	72%	81%	70%	66%	72%	0.65	0.76	0.03	1.58	0.13	0.31	0.17	0.32
Farmers Capital Bank Corp.	FFKT	97%	92%	71%	67%	82%	0.65	0.63	0.03	3.52	0.20	0.10	0.15	0.08
Alamo Group	ALG	79%	77%	90%	70%	79%	0.65	0.54	0.05	4.18	0.29	0.28	0.27	0.26
Northwest Pipe Co	NWPX	64%	67%	71%	72%	68%	0.75	0.53	0.06	5.36	0.61	0.40	0.44	0.27
Oil-Dri Corp of Amer	ODC	82%	68%	76%	70%	74%	0.55	0.51	0.03	3.10	0.30	0.51	0.40	0.68
Samuel Manu-Tech Inc.	SMT.TO	53%	58%	86%	77%	68%	0.60	0.56	0.09	3.02	0.60	0.48	0.51	0.50
Meadowbrook Ins Grou	MIG	100%	59%	83%	78%	80%	0.60	0.81	0.11	8.71	0.26	0.56	1.01	
Frisch's Restaurants	FRS	N/A	67%	67%	75%	75%	0.60	0.58	0.03	6.13	0.47	0.23	0.69	0.47
Sunlink Health Sys	SSY	77%	24%	79%	80%	65%	0.80	0.64	0.14	2.60	0.28	0.96	0.60	
NAPCO Security Systems Inc.	NSSC	70%	60%	86%	92%	77%	0.80	0.48	0.05	2.23	0.12	0.65	0.10	0.75
Old Second Bancorp	OSBC	100%	79%	81%	83%	86%	0.75	0.56	0.06	9.05	0.28	0.16	0.54	0.43
Village Super Market 'A'	VLGEA	70%	66%	80%	85%	75%	0.60	0.63	0.05	7.74	0.32	0.15	0.73	0.46
Utah Medical Prods.	UTMD	80%	88%	100%	89%	89%	0.55	0.58	0.03	8.84	0.35	0.20	0.60	0.47
SL Inds. Inc.	SLI	98%	97%	96%	72%	91%	0.95	0.84	0.03	3.34	0.49	0.56	0.73	1.21
Average		73%	65%	72%	68%	70%	0.70	0.62	0.06	5.94	0.36	0.37	0.48	0.45
Standard deviation						14%	0.12	0.10	0.03	3.28	0.22	0.24	0.24	0.25

APPENDIX VI

ESTIMATES OF COST OF EQUITY: Canadian Utility Companies (CN sample 1)

CAPITAL ASSET PRICING MODEL

TSX LISTED UTILITIES (Sample 1)

Company Name	Ticker	CAPM Beta, 2002 - 2006 Adjusted	Unadjusted
Canadian Utilities	CU	0.86	0.72
Enbridge Inc.	ENB	0.82	0.67
Gax Metro	GZM	0.94	0.84
Fortis Inc.	FTS	0.82	0.67
Transalta Power	TPW	0.93	0.84
Emera Inc.	EMA	0.84	0.71
	Average	0.87	0.74
	Standard Deviation	0.05	0.08
	Weighted Average:	0.85	

AVERAGE YIELDS AND OVERALL MARKET RETURNS

	1-Year Gov't Debt Interest Rates	10-Year Gov't Debt Interest Rates	30-Year Gov't Debt Interest Rates	TSX Total Return	Variation in Monthly TSX Returns (S.D.)
2000	5.75%	5.84%	5.12%	11.59%	6.16%
2001	7.05%	10.88%	10.82%	-17.62%	5.93%
2002	3.01%	5.37%	5.55%	-14.24%	3.93%
2003	2.95%	4.90%	5.28%	26.68%	2.63%
2004	2.48%	4.66%	5.14%	8.04%	2.36%
2005	3.00%	4.08%	4.35%	27.09%	3.64%
2006	3.87%	4.17%	4.06%	9.15%	2.68%
Average	4.01%	5.70%	5.76%	7.24%	3.90%
Average,'02-'06	3.06%	4.64%	4.88%	11.34%	2.83%

VARIATION IN YIELDS AND RETURNS, OVER YEARS

	1-Year	10-Year	30-Year	TSX Returns Return
Standard Deviation	1.72%	2.37%	2.29%	17.68%

CANADIAN UTILITY COMPANIES (Sample 1)

CAPM ESTIMATES OF COST OF EQUITY CAPITAL

Market Cost of Equity Capital, Unadjusted		Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	9.10%	4.16%	0.86	9.92%	4.16%
High	12.47%	5.11%	0.88	13.48%	5.11%
Average	10.39%	4.64%	0.87	11.26%	4.64%

Canadian Equity Market Risk Premia, '91 - '06: 6.63%

0713

ESTIMATES OF COST OF EQUITY: Canadian Utility Companies (CN sample 2)

CAPITAL ASSET PRICING MODEL

TSX LISTED UTILITIES (Sample 2)

Company Name	Ticker	CAPM Beta, 2002 - 2006 Adjusted	Unadjusted
Pacific Northern Gas	PNG	0.91	0.81
Maxim Power Corp	MXG	0.99	0.79
Canadian Hydro	KHD	0.91	0.80
Manitoba Telecom	MBT	0.87	0.74
TransCanada Pipelines	TRP	0.82	0.67
Average		0.90	0.76
Standard Deviation		0.06	0.06
Weighted Average:		0.830	

AVERAGE YIELDS AND OVERALL MARKET RETURNS

Year	1-Year Gov't Debt Interest Rates	10-Year Gov't Debt Interest Rates	30-Year Gov't Debt Interest Rates	TSX Total Return	Variation in Monthly TSX Returns (S.D.)
2000	5.75%	5.84%	5.12%	11.59%	6.16%
2001	7.05%	10.88%	10.82%	-17.62%	5.93%
2002	3.01%	5.37%	5.55%	-14.24%	3.93%
2003	2.95%	4.90%	5.28%	26.68%	2.63%
2004	2.48%	4.66%	5.14%	8.04%	2.36%
2005	3.00%	4.08%	4.35%	27.09%	3.64%
2006	3.87%	4.17%	4.06%	9.15%	
Average	4.01%	5.70%	5.76%	7.24%	4.11%
Average,'02-'06	3.06%	4.64%	4.88%	11.34%	2.88%

VARIATION IN YIELDS AND RETURNS, OVER YEARS

	1-Year	10-Year	30-Year	TSX Returns Return
Standard Deviation	1.72%	2.37%	2.29%	17.68%

CANADIAN UTILITY COMPANIES (Sample 2)

CAPM ESTIMATES OF COST OF EQUITY CAPITAL

Market Cost of Equity Capital, Unadjusted		Risk-Free Rate	Market Beta, Adjusted	Expected Market Return	Risk Free Rate
Low	9.27%	4.16%	0.89	9.92%	4.16%
High	12.76%	5.11%	0.91	13.48%	5.11%
Weighted Average	10.60%	4.64%	0.90	11.26%	4.64%

Canadian Equity Market Risk Premia, '91 - '06: 6.63%

ESTIMATES OF COST OF EQUITY: Canadian Utility Companies (CN samples 1&2)

HISTORICAL MARKET RETURNS

CANADIAN UTILITIES (Sample 1)

Company	2002	2003	2004	2005	2006
Canadian Utilities	2.94%	15.03%	8.23%	50.58%	11.54%
Enbridge Inc.	-1.83%	28.04%	15.18%	25.51%	14.41%
Gax Metro	7.64%	21.01%	5.63%	-5.44%	-14.29%
Fortis Inc.	11.78%	14.20%	22.12%	42.79%	25.28%
Transalta Power	-20.79%	11.17%	3.33%	47.54%	9.24%
Emera Inc.	-2.90%	12.57%	12.80%	15.09%	12.32%
Average	-0.53%	17.00%	11.21%	29.34%	9.75%
				Average Across Years:	13.36%

CANADIAN UTILITIES (Sample 2)

Company	2002	2003	2004	2005	2006
Pacific Northern Gas	0.00%	0.00%	0.00%	-2.75%	-3.56%
Maxim Power Corp	-34.29%	82.61%	-11.90%	97.30%	-7.12%
Canadian Hydro Developer:	9.27%	-1.79%	54.09%	71.98%	2.06%
Manitoba Telecom Services	2.16%	25.68%	15.74%	-12.69%	21.68%
TransCanada Pipelines	15.34%	24.17%	11.38%	27.54%	14.94%
Average	-1.50%	26.13%	13.86%	36.28%	5.60%
				Average Across Years:	16.07%

МТО

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates.

AFFIDAVIT OF MICHAEL O'SHEASY

I, **MICHAEL O'SHEASY**, of 5001 Kingswood Drive, Roswell, Georgia, in the United States of America being duly sworn make oath and say as follows:

INTRODUCTION

1. I am a Vice President at Christensen Associates Energy Consulting, LLC ("Christensen" or "CAEC"), a subsidiary of Laurits R. Christensen Associates, LLC, an economic research and consulting firm. The organization in which I work serves the needs of energy companies. My responsibilities include supervising the efforts of a team of CAEC economists. The team assisted The Barbados Light & Power Company Limited ("BLPC" or "the Company") in the filing of an application for a review of electricity rates ("the Application"). The team included Dr. Steven Braithwait who focused upon load sampling and load research development, Dr. Mike Welsh who was primarily involved with cost of service, Mr. Bruce Chapman who performed an integral administrative role and assisted in load research and rate design, Mr. David Armstrong who assisted with statistical analyses and marginal cost, and Mr. Robert

Camfield who led the development of cost of capital and marginal cost. Prior to joining Christensen, I worked for one of the largest electric utilities in North America, the Southern Company and its subsidiary Georgia Power Company, from which I retired in 2001. I have authored a number of professional articles which are set out in my resume. The resume also contains an overview of my responsibilities and the names of the utilities to which I have consulted. A copy of my resume is attached hereto and marked as Exhibit "**MTO1**."

EDUCATION AND PROFESSIONAL EXPERIENCE

2. I received a Bachelor of Industrial Engineering degree from Georgia Institute of Technology in 1970. In 1974, I earned a Masters in Business Administration degree from Georgia State University. From 1971 to 1975, I was employed by the John W. Eshelman Company, a Division of the Carnation Company, as a plant superintendent in their Chamblee, Georgia operation. From 1975 to 1980, I worked for the John Harland Corporation initially as an assistant plant manager and then as a plant manager in its Jacksonville, Florida plant and later as their plant manager in Miami, Florida. I joined Southern Company Services ("SCS") in 1980 as an engineering cost analyst and progressed through various positions, during which time I began serving as an expert witness in costing. I testified as Gulf Power Company's cost-of-service expert witness and provided other support to Gulf Power in matters before the Florida Public Service Commission. In 1990, I became Manager of Product Design for Georgia Power Company ("Georgia Power" or "GPC") and testified before the Georgia Public Service Commission as an expert witness on rate design and pricing. I retired from Georgia Power on May 1, 2001, and became a consultant with Christensen. I have also testified before the Public Service Commission of the Commonwealth of Kentucky and the Corporation Commission of the State of Oklahoma as an expert witness on rate design and costing.

PURPOSE OF TESTIMONY

3. The purpose of my testimony is to present and explain the embedded cost-of-service ("COS") study which was prepared by CAEC for BLPC in

support of the Application. In April 2007, CAEC was retained by BLPC to prepare a COS study. A copy of the embedded COS study is attached hereto and marked as Exhibit "**MTO2**." This study was prepared under my supervision and conforms to sound and accepted cost-of-service principles applied by the regulatory authorities within the electricity industry in the U.S.A. I shall provide the reasons for my conclusions in the COS study and the methods which were employed to establish my reasons. I shall also offer opinions on the proposed rate designs for BLPC.

<u>WHAT IS A COS STUDY AND WHAT IS ITS TRADITIONAL USE IN REGULATORY PROCEEDINGS?</u>

4. A COS study is first a compilation of a utility's total electric investments, revenues, and expenses that are used and useful in providing electricity. It divides these costs among rate groups by allocating or directly assigning the company's revenues, investments, and expenses among the various rate groups served by the company. This division is done based upon the causative nature of the costs incurred. The Federal Energy Regulatory Commission ("FERC") of the United States of America indicates that a guiding principle is that the allocation must reflect cost causation.[1] The results of the COS study will reveal the rate of return being earned by the company based on the different rate groups that are served by the company.

5. A COS study is traditionally used as the primary tool to determine the cost of providing electricity based upon costs authorized by the regulatory body. The COS study reveals how well overall costs are being covered for the regulated utility as well as individual cost coverage by the specific rate groups of customers and therefore shows the earnings for the company and its rate groups.

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[1] *See, e.g., Kentucky Utilities Co., Opinion No. 116-A, 15 FERC 61,222, p. 61,504 (1983); Utah Power & Light Co., Opinion No. 113, 14 FERC 61,162, p. 61, 298 (1981).*

6. In order for regulators to review the company's earnings and to evaluate the contribution made by the various rates to cover costs, it is necessary to analyze the cost to serve the respective rate groups. BLPC, like many other electric utilities, maintains its books and records in accordance with "International Financial Accounting Standards" under the historic cost convention which are generally considered to be sound accounting principles. This system of recording, which is traditionally based upon financial costs, does not separate the Company's investments, revenues, and expenses by rate groups. Hence, the COS study conducted for BLPC accomplishes this objective.

7. Since a goal of a COS study is to identify what costs are incurred to provide service to certain groups of customers, such a COS study can be a useful (and often times the primary) tool for determining the adequacy of current rates. For those rates which the COS study reveals as inadequate at current rate levels, the COS study is an appropriate tool for determining what rate changes should be made.

8. The Fair Trading Commission ("FTC") can use these costs of service results to ascertain the utility's overall revenue requirement as well as evaluate the adequacy of rates for the different classes. The National Association of Regulatory Utility Commissioners ("NARUC") in the United States of America identifies the COS study as among the basic tools of ratemaking, and it is used to attribute costs to different categories of customers based on how those customers cause costs to be incurred.[2]

9. The three major uses of the COS study in the preparation of the Application were: (1) to observe the earnings under present and proposed revenue based on the rate base and net operating income, (2) to ascertain how well each existing rate group covered cost, and (3) to assist BLPC in the design of the proposed rates for their rate groups and customers.

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[2] *ELECTRICITY UTILITY COST ALLOCATION MANUAL*, January 1992, NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISONERS.

GUIDING PRINCIPLES AND OBJECTIVES FOR COST OF SERVICE

10. The overall objective is to assign or allocate costs fairly and equitably to all customers. This objective is accomplished when the resulting COS study reflects "cost causation," *i.e.*, those customers who caused a particular cost to be incurred by the Company in providing them service should be responsible for those costs.

11. When certain costs are readily identified with a particular customer group, the assignment of those costs to that group clearly reflects cost causation, and is fair and equitable to all rate groups and customers. However, it must be recognized that most parts of an electric system are planned, designed, constructed, operated, and maintained to serve all rate groups and customers. The majority of BLPC's costs have been incurred to serve all rate groups of customers, and these costs are referred to as joint or common costs. Joint or common costs must be allocated to rate groups based on the nature of the costs incurred, and the aggregate requirements and service characteristics of the customers that caused the costs to be incurred. The industry over time has developed a number of standard allocation methods that are generally accepted in the industry as reasonable. By adhering to this fundamental and essential principle of cost causation and thereby using appropriate allocators, the results of the COS study will be fair and equitable to rate groups and customers.

MAJOR DRIVERS IN COST CAUSATION

12. There are three primary drivers that cause costs to be incurred by an electric utility. Therefore, costs are classified into three respective components: (1) a demand-related component based upon peak demands (kWs), (2) an energy-related component based upon kilowatt hours (kWhs), and (3) a customer-related component based upon number of customers. Some costs are incurred to meet peak demands, i.e., the highest quantity of electricity required over a specified short time interval. Other costs are incurred to provide the total quantity of electricity (energy measured in kWh) requested over a longer time interval, usually a year. Still other costs are driven by the number of customers, that is by the fact that a customer is simply being served (hooked up to the electric system).

Each of these three drivers has its own separate and respective demand-related, energy-related, and customer-related allocators to spread its respective costs to the associated rate groups.

HOW THE ANALYSIS IS PERFORMED

13. The utility company's financial data are compiled and analyzed to determine how groups of rates influence the actual incurrence of cost by the utility. This review discloses certain direct costs that should be directly assigned to the specific rate group for which these costs were directly incurred. However as previously mentioned, the majority of costs is incurred to perform a common function within the electric system for various rate groups, and therefore must be allocated to the various rate groups of customers.

14. The utility's financial costs are in general at too high an aggregate level of detail to allocate accurately to rate groups. The financial data must therefore be divided into smaller components, small enough to apply appropriate cost-based allocators. The financial data are divided into the functional service that they provide and next into their respective level of service. The final task is to divide these costs into their cost-causative component (i.e., the three cost drivers: demand component, energy component, and customer component). This task is often referred to as "classification" of costs. An example of this division of costs into cost-causative component is substation transformers. Since substation transformers are normally sized for maximum demand requirements, it is by general agreement in the profession that substation transformers should be considered in the demand component.

15. Once costs have been analyzed to disclose their functions, level of service, and appropriate cost-causative component category, then the corresponding allocator can be applied to apportion these common costs to the area of responsibility. By eventually summing all of these allocated common costs along with the directly assigned costs by rate group and with revenues received, the rate of return for each rate group can be determined.

SUMMARY OF THE MAJOR STEPS THAT ARE REQUIRED TO PERFORM A COS STUDY

16. Typically the electricity industry undertakes six fundamental steps when conducting a COS study. These steps are: (1) financial data compilation, (2) functionalization, (3) levelization, (4) classification, (5) assignment; and (6) allocation.

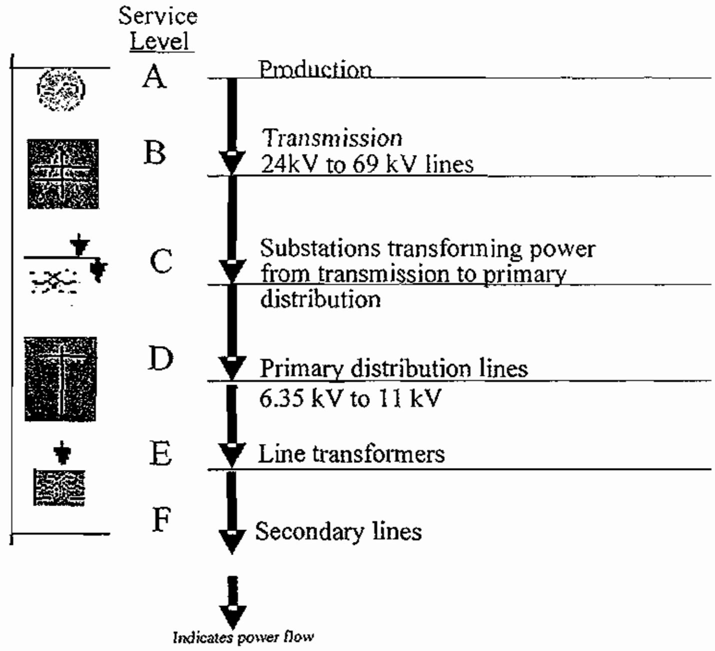
(1) Financial data compilation is the process of gathering and compiling the revenue, expenses, and investment items that are *used and useful* in providing electric service for the test period. It is this data when divided among the rate groups that will enable parties to determine how well customer groups are covering the cost to serve them.

(2) Functionalization separates the investment and expenses of the Company into specific functions based on the operations involved in providing electric service. Those functions are production or generation, transmission, distribution, and general plant. General plant supports the three primary functions of production, transmission, and distribution, and also provides customer services (customer accounting, customer assistance, billing, etc.), and administrative and general (A&G).

(3) Levelization separates costs into service levels that are associated with producing electricity and delivering it to customers across the system. The service level designations are a means of identifying and associating investment and expenses with rate groups of customers and their loads at established points of service. In general, the lower the particular level of service required by the rate group, the greater is the cost of providing service since additional equipment is necessary to deliver service to lower levels of service. In addition, more losses are incurred in the delivery process for lower levels of service.

The following power flow diagram illustrates the paths on which electricity flows through the BLPC system. These paths are indicated on the chart by vertical lines. The horizontal lines identify the various levels of service that are necessary in providing electric service. These service levels enable the efficient allocation of costs to rate groups. The letter designations of service levels on the left side are a means of identifying the investment and expenses at these established points. These levels are referred to in the COS study on *numerous occasions. This allows for the proper identification and* association of system cost responsibility with the rate group's requirements to serve them at the respective service levels.

Service Level Designation and Power Flow Diagram



(4) Classification segregates costs into the three primary components of cost drivers based upon the "cost causative" characteristics for each account of the investment and expense elements within each function. As previously mentioned, these components are:

(a) Demand component: those costs that are incurred as a consequence of the magnitude of the load imposed on the system by customers over short intervals of time. This generally refers to costs experienced by the utility in order to *provide the capacity necessary to serve the instantaneous* peak load(s) throughout the year.

(b) Energy component: those costs that vary with the amount of energy consumed by the customer over long periods of time. This generally refers to costs such as fuel and variable operations and maintenance expenses which vary with the kilowatt-hours (kWh) consumed by the customers.

(c) Customer component: those costs that vary with the number of customers on the system. This generally refers to the costs incurred by the utility to attach a customer to the distribution system and be ready to serve him or her, and for customer metering, customer billing, and certain administrative functions.

(5) Direct assignment is the association of specific cost and revenues with specific customers or rate groups where cost causation can be directly identified with this specific rate group of customers.

(6) Allocation is the division of joint and common costs according to well-established rules for cost allocation by using allocators based upon cost causation.

17. The above steps were employed in the preparation of the COS Study for BLPC.

EXAMPLE OF THE IMPORTANCE OF PROPER CLASSIFICATION AND ALLOCATION

18. A meter is necessary to measure the amount of electricity provided to a customer. Within limits, a meter can operate adequately regardless of the maximum demand and overall quantity of electricity requested. The cost of a meter incurred by the utility to serve a customer does not vary with quantity of energy used; rather, it is driven by the fact that each customer needs a meter. As a result, utilities will usually consider meters to be customer-related, and therefore allocate meter costs to a rate group based upon an allocator which reflects the number of customers in these rate groups.

19. If meters were misclassified as kWh-related, then the corresponding kWh allocator would spread more meter cost to large customers and less meter cost to small customers, despite the fact that the large customers and the

small customer in this example both required the same meter with related cost incurrence by the utility.

PURPOSE OF THE ALLOCATIONS AND HOW ALLOCATORS WERE DEVELOPED FOR THE COS STUDY

20. In general there are two primary steps and purposes of the allocations: one is to allocate the financial costs to cost functional category and the other is to allocate the resultant functional category financial costs to BLPC's five rate groups: Domestic Service, General Service, Secondary Voltage Power, Large Power, and Street Lighting. The cost functional categories can be observed in Schedules 5 and 6 to Exhibit "MTO2," as column headings. Sometimes mere direct assignments can be made if BLPC accounting records are separated to that degree. In most situations though, cost-causative allocators must be developed. BLPC provided analyses which often help to allocate to cost functional category and possibly even to rate group. An example of a Company-provided allocator to cost functional category would be the division of investment in poles to distribution service levels D and F in which BLPC provided such an analysis of poles by service level. Allocators for the various accounts to cost functional category can be viewed in Schedules 9-13 of Exhibit "MTO2."

21. The development of allocators to rate group began with the collection and analysis of load research data. The process began with BLPC providing to me an enumeration of the utility's customers by rate and service level, along with their annual kWh. Christensen, under my supervision, developed a stratified random load research sample designed to meet industry standard statistical accuracy of 10 percent error at a 90 percent confidence level. BLPC then placed hourly interval data recorders on the resulting overall sample of 405 customers distributed by rate, providing hourly demands (kW) for the period October 8, 2007 through July 1, 2008. These sample load data were then expanded to the rate population using kWh-based sample expansion factors that were based on the original stratified sample designs. This produced hourly load shapes by rate. The hourly load shapes for General Services ("GS") and Secondary Voltage Power ("SVP") were then apportioned to the two separate service levels at

which they receive service on the basis of information provided by BLPC on the proportion of load for each respective rate that is served at each respective service level. Each rate population's hourly values for the sampled period were then scaled to provide hourly load shapes for a 12-month time period for 2008. These load shapes for the different rate levels provided the ability to identify specific peak demands for each rate group for each month of the 2008 test year.

22. Next, the number of customers and their respective demand and energy sales by level of service were analyzed, as well as the supply including losses for annual system energy and demands. The demands of interest by rate group were at the time of BLPC's monthly coincident peaks (MCP) or during the non-coincident individual rate peaks (NCP). Load flows were created and balanced at the various service levels.

23. This balancing of system load flows for demand and energy were developed through a load flow program, which computes total system losses for each service level. The load flow process begins by taking the total system energy sales at Level F (the secondary distribution lines level), multiplies these sales by the loss percentage at Level F, and then combine these calculated losses and sales. This amount is then added to the system sales at Level E, and this new total is in turn multiplied by the loss percentage at Level E. This procedure is continued up to Level A, the production level. Comparisons are made to the actual system loads by hour at the production level and the program then adjusts the loss percentages at each level and iterates the above process until the sum of the losses at each level matches the total system losses, and a balanced flow is produced. These total system loss percentages are then applied to each rate group's sales, and then rolled up into the respective service levels by adding loads plus losses for each respective rate group. Each rate group's loads with losses at that service level will become a part of the allocator for each respective service level. This process calculates the demand allocators known as the "12-MCP," "3-MCP," "NCP," and "energy" allocators along with the "number of customers" allocator (although there are no losses necessary for the "number of customers" allocator).

24. In some instances, an allocator is "mixed" and is created by combining several allocators into one aggregate allocator that best reflects how

these costs are incurred. An example of this combining is the Salaries and Wages (S&W) allocator.

25. In Schedules 9-13 of the COS study found in Exhibit MTO2, adjacent to the accounting description is the designation of the allocator of financial costs to cost functional category. Schedules 3-7 will indicate how the financial cost functional category totals are allocated to rate group. "DA" indicates a direct assignment of cost rather than an allocation.

26. The rationale and use of these allocators are explained in the COS study.

SOURCE OF FINANCIAL DATA FOR THE COS STUDY

27. The financial information for BLPC for the test year of 2008 was provided by Mr. Hutson Best, Chief Financial Officer of BLPC. These investment, revenue, and expense items were then assigned or allocated to each rate group by me and my team of analysts. All data were provided in an acceptable manner and clearly explained.

HOW THE CAPITAL COSTS AND RELATED O&M EXPENSES FOR PRODUCTION WERE ALLOCATED

28. Production investment/capital-related costs, which are found at Level A, are first classified as demand-related and then allocated using the 12-MCP. The 12-MCP demand is the sum of the highest kilowatt load for BLPC predicted to occur in each month of the test year divided by twelve. This concept incorporates the fact that BLPC's system is planned and operated for the purpose of meeting these demands for electricity every month of the year as well as the fact that the Company's system load shape is relatively consistent throughout the year. It also reflects a consideration for scheduled maintenance, unscheduled outages, and the fact that Barbados is an island utility without interconnections to other utilities. 12-MCP is one of the most common and popular allocators throughout the industry.

29. I have seen a copy of an embedded Cost-of-Service Study of BLPC undertaken for the Fair Trading Commission by NERA Economic Consulting in 2006. In this study, NERA used a technique called "Cap-Sub" to first classify investment/capital related costs of production to

demand and energy. The energy cost classification is supposed to reflect costs which are incurred to provide cheaper energy. The residual is considered to be demand-related.

30. Cap-Sub has some philosophical logic and appeal. It does make sense that some resources such as low-speed diesel units are selected today to enable lower energy costs. However, the implementation of such a methodology is complex, controversial, and a utility's planning constraints and circumstances may change over time. Classification of production plant as all demand-related and use of 12-MCP as the allocator for these costs has a solid rationale and traditional usage within the industry and Barbados. 12-MCP allocation of all production cost recognizes that generating requirements are sized to serve the maximum loads to be imposed upon the system throughout the year, maintenance requirements must be met, and it accommodates well the system's relatively consistent, flat load shape without significant seasonal patterns of usage. 12-MCP allocation is also relatively stable in its COS impacts over time, simple to administer, possesses sound philosophical logic, has been proven with widespread usage and acceptability over long periods of time, and aligns well with a flat fuel clause like the Company's Fuel Adjustment Clause (FAC). Therefore we selected 12-MCP as the allocator for production capital cost.

31. I did examine the Cap-Sub splits into demand and energy components derived by NERA along with their use of 12-MCP for the allocation of the Cap-Sub demand cost and with an energy allocation for the residual energy piece of production. The conclusion is that if these Cap-Sub factors were applied to the present COS study, it would not create materially different earnings implications from the Company's COS study use of demand classification of all production and resultant 12-MCP allocation of all production. It appears that the biggest impact of NERA's Cap-Sub factors would be a decrease in the Domestic Service class's rate of return (ROR) which would then suggest a higher rate increase for Domestic than the COS study.

32. A complete and specific listing of all account allocations, is provided in the COS study found in Exhibit MTO2.

33. **Exhibit MTO2 Outline.** This exhibit is the COS report and study for BLPC. There is an index which provides a listing of schedules and designates the major sections of the COS study. Schedule 1 presents, in summary form, the results of the COS study for the total system and by the five rate groups for the test period ended December 31, 2008. One can observe the earnings position under present rates and proposed rates for BLPC and each of the five rate groups. The parity ratios shown in Schedule 1 are the ratios of the rate groups' rates of return divided by the rate of return for BLPC.

34. Schedule 2 provides cost functional category definitions and rate group listings which are used in the COS study along with the cost functional category allocators to rate group. Schedule 3 is a listing of each of the allocators to rate group used in the COS study.

35. The remainder of the schedules provides the supporting analyses which reveal the actual allocations or direct assignments to cost functional category or rate group. Starting from the back of these schedules and working forward, Schedules 9-13 list the individual expense and investment accounts and their allocators to cost functional category. Schedule 8 provides a detail of revenues by rate group. Schedule 7 is the allocation of income taxes to rate group. Schedule 6 reveals the compilation of the individual expense elements by cost functional category. Schedule 5 compiles the investment elements which make up Rate Base by cost functional category. Schedule 4 allocates the Rate Base and Expense cost functional categories to the five rate groups. The allocated results from Schedule 4 along with the revenues found in Schedule 8 and allocated income taxes in Schedule 7 then feed the Summary Page, Schedule 1.

36. Schedule 14 aggregates the resultant costs, including the returns found in Schedule 1 for each rate group, and breaks them down into the three cost components of demand-related, energy-related, and customer-related. It then takes these cost totals by component and divides by the rate group's respective billing determinants for that cost component. This reveals unit costs by rate group and cost component within each rate group.

37. These unit costs which show the costs that each rate group imposes upon BLPC are an important benchmark to begin the rate design process. As previously mentioned, traditional regulation encourages rates to be cost-based. These unit costs were therefore provided to the rate designers, under the supervision of the Chief Marketing Officer, Mr. Worme, to begin their rate design process. For various reasons, such as a consideration of the rate impact upon low income customers, rates will not exactly match unit cost, but the proposed new rates are reasonably close.

38. In order to evaluate the earnings of the rate groups in a COS study, it is necessary to properly consider the fact that fuel-related costs are recovered through the fuel clause adjustment. Fuel-related cost should therefore not affect earnings. Because there is often a timing imbalance between when fuel expenses are incurred and fuel revenues are received in a test period, it is sometimes necessary to make a fuel timing adjustment. The computation of this adjustment can be seen in Schedule 15 and the resultant adjustment shows up on Schedule 8 of Exhibit MTO2.

SUMMARY AND CONCLUSIONS REGARDING THE COS STUDY

39. In my professional opinion and based upon my experiences with many other utilities' COS studies, the COS study found in Exhibit MTO2 is a reasonable and accurate reflection of the cost of serving BLPC's customers. The results can be observed in the Summary Page (Schedule 1) of the COS study. This COS study can be used as an excellent tool to assist in the evaluation of BLPC's earnings for the various rate groups for the test period and therefore can be used to influence proposed rates. Although there are other ways to allocate costs, BLPC's methodologies are sound, objective, and consistent with the methodologies used in numerous other cases throughout the industry, and provide, in my view, the most accurate information for the FTC to evaluate revenue and rate adequacy.

SUMMARY AND CONCLUSIONS REGARDING THE RATE DESIGNS

40. Pertinent cost information from the COS study was provided to the rate designers of BLPC and correctly employed in the designs. BLPC's proposed rate designs conform to sound and acceptable cost of service principles applied by the regulatory authorities within the electricity industry in the United States of America. I have been involved with the development of the proposed rate designs as well as the new pilot tariffs. BLPC, in its design process, began with the proposed revenue requirements from the COS study as its revenue target for the new rate designs. Furthermore, BLPC considered the unit cost results of the COS study by rate in order to guide its rate component prices. This is a recommended procedure for creating cost-based pricing products. As a result, BLPC proposes to increase the customer and demand charges relative to the energy charges. I concur with the new customer charges for the Domestic Service and General Service tariffs. This will better enable alignment with the customer-related unit costs in the COS study. It is usually best to align prices with costs in order to send proper price signals to customers unless there is some obvious compelling justification to do otherwise. Likewise, I agree with the decision to increase the demand charges for SVP and LP. In addition, I concur with the creation of the new pilot tariff and riders offering, and I believe them to be valuable additions to the portfolio of pricing products offered to customers of BLPC. In summary, the proposed rate designs are reasonable reflections of the cost of serving BLPC's customers. The proposed rates include sound cost-based rate design components and comport with pricing procedures that are common to the industry.

SWORN TO by the deponent)
Michael O'Sheasy)
this 6 day of May 2009)
before me:

Michael O'Sheasy

NOTARY PUBLIC

I, C. J. Kell , Notary Public in and for the State of
in the United States of America, do hereby DECLARE that on the
day of May 6 2009, personally appeared before me a male person who identified himself to be the within named MICHAEL O'SHEASY and did in my presence sign and execute the Affidavit as and for his free and voluntary act and deed.

IN TESTIMONY WHEREOF I have hereunto subscribed my name and affixed my seal of office this 6 day of May , 2009.

Notary Public

C. J. KELL NOTARY EXPIRES GEORGIA July 8, 2012 PUBLIC CHEROKEE COUNTY

0734

MT01

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates

EXHIBIT "MTO1"

This is a true copy of my resume marked Exhibit **"MTO1"** mentioned and referred to in paragraph 1 in the said Affidavit of Michael O'Sheasy.

SWORN TO by the deponent)
Michael O'Sheasy)
this 6 day of May 2009)
before me:

Michael O'Sheasy

NOTARY PUBLIC

I, C. J. Kell, Notary Public in and for the State of in the United States of America, do hereby DECLARE that on the 6 day of May 2009, personally appeared before me a male person who identified himself to be the within named MICHAEL O'SHEASY and did in my presence sign and execute the Affidavit as and for his free and voluntary act and deed.

IN TESTIMONY WHEREOF I have hereunto subscribed my name and affixed my seal of office this 6 day of May, 2009.

Notary Public

GEORGIA
July 8, 2012
PUBLIC
CHEROKEE COUNTY

EXHIBIT "MTO1"

Michael T. O'Sheasy

RESUME

January 2009

Addresses:

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5001 Kingswood Drive
Roswell, GA 30075
Telephone: 770.993.2336
Fax: 770.993.5419
Cell Phone: 770.337.1817

Academic Background:

MBA, Georgia State University, 1974
Bachelors of Industrial Engineering, Georgia Institute of Technology, 1970

Positions Held:

Vice President, Christensen Associates Energy Consulting, LLC., May 2001-present
Manager, Product Design, Georgia Power Company, 1990-April 2001
Economic and Costing Analysis Dept, Southern Company Services, 1980-1990

Professional Experience:

I help utilities develop successful rate cases and new tariff filings based on both embedded and marginal cost of service and contemporary ratemaking principles. Expert testifying is available for both costing and pricing. Clients are encouraged to review and revise their retail portfolios to take advantage of the opportunities of improved pricing efficiency. I advise clients in developing and implementing innovative pricing products that extend utility customers' choices and improve the utility's bottom line and margin coverage. Other examples of the expertise provided to clients are advanced marginal costing, more accurate cost allocations methodologies, and fuel cost recovery clause enhancements. Prior to joining Christensen Associates, I directed real-time pricing and other innovative break-through rate structures including Price Protection Products, Daily Energy Credits, and FlatBill at Georgia Power Company, the largest operating company in the Southern Company system. I was responsible for retail and wholesale rate filings and other regulatory requirements. I have routinely testified before various commissions on both costing and pricing. I have published numerous articles on pricing in many journals including *Natural Gas and Electricity, TAPPI Journal, Public Utilities Fortnightly, Electric Perspectives, EPRI Journal, Energy Customer Management*, and *The Electricity Journal*. On a national media level, I have been interviewed in *USA Today*, *Newsweek*, and National Public Radio. I have been featured on the front page of the *Wall Street Journal* and I have appeared in a live interview on CNN FN.

Major Projects:

May 2001 – Present: Vice President, Christensen Associates Energy Consulting

Lead a cost of service and rate redesign project for a Midwest municipality.

Project Manager for a rate strategy project for TVA.

Consultant to The Barbados Light and Power Company Limited for their rate case filing.

Expert witness on cost of service for Georgia Power Company's 2007 rate case.

Consultant to Nova Scotia Power Inc. on Real Time Pricing.

Expert witness for EKPC for their Real Time Pricing pilot filing with the Kentucky Public Service Commission.

Expert witness on cost of service for Gulf Power's rate case.

Consultant to major IOU in Southwest for a retail rate case filing in 2007.

Consultant to Lincoln Electric Service on a cost of service audit.

Consultant to Georgia Power Company on a fixed bill product for mid-size business customers including product design, market research, approval, marketing, and training.

Witness and consultant to Oklahoma Gas & Electric on fixed bill project. Design was completed and approved for implementation.

Consultant to the Electric Power Board on fixed bill design, approval, and tracking.

Consultant to two separate Southeastern utilities on pricing strategy and pricing portfolio design.

Project Manager for Southeastern utility on design of an economic development rate for their largest customer.

Witness for large commercial customers in a major rate case requesting implementation of Real Time Pricing.

Consultant to large Pacific Northwestern utility on Real Time Pricing pilot program.

Consultant and witness to several mid-western utilities on the design and approval of a fixed bill product.

Consultant to utility on Real Time Pricing price response project.

Project Manager for Southeastern utility's research into a time of use fuel clause.

Consultant to mid-Atlantic utility on fixed bill in their competitive electricity market.

Consultant to two mid-west utilities on Real Time Pricing.

Consultant to Georgia Power, Duke Power, Gulf Power Company, and Progress Energy on the design, approval, and implementation of fixed bill products.

Consultant to California Energy Commission on the advancement of Real Time Pricing in California.

Consultant to Caribbean utility on pricing products and rate case filing.

1990 – April 2001, Manager, Product Design, Georgia Power Company

Responsible for managing the pricing and rates research activities of the Company. Activities included pricing strategy development and future rate planning; rate research, design, and evaluation; the preparation and filing of retail rates with the Georgia Public Service Commission and the forecast of base rate revenues for the corporate budget.

Supported all regulatory proceedings by preparing rate case filings, including rate designs and testimony, training witnesses and briefing counsel for regulatory proceedings. Worked with the Public Service Commission staff and various customer/intervenor groups, providing adequate supporting evidence for obtaining PSC approval and customer acceptance of the proposed tariffs, rules, and regulations.

Developed embedded and marginal cost-of-service by rate or customer group and used these estimates and projections in the profitability assessments needed for innovative pricing strategies, such as demand-side rate options and market-based pricing.

Directed the rate research, design, and evaluation activities of the Company to develop a rate package, which contributed to the Company's marketing, financial, and corporate goals while satisfying the requirements of the Georgia PSC.

Developed innovative rate concepts which support the Company's marketing efforts and contribute to the competitiveness and profitability goals of the Southern Company. Developed long-term competitive pricing strategies and designed rate research programs for potential future rate options for evaluation and implementation. Created innovative pricing methodologies including Real Time Pricing, Multiple Load Management, Multiple Account Management, Interruptible Exchange Service, Flat Bill, and Price Protection Products. Also, directed efforts of "Pricing for the '90s" which will produce the most optimal, efficient pricing methods for Georgia Power Company's needs during the exciting, competitive 2000's.

Managed Real Time Pricing Program. Designed a customer specific profitability model (CPM). Presented over 100 speeches on pricing in state, national, and international forums.

1980 – 1990, Economic and Costing Analysis Department, Southern Company Services

Progressed through various levels of responsibility. Positions and activities include:

Engineer:

Assisted in the development of Cost of Service Studies for rate case filing. Developed jurisdictional and class analysis on individual projects such as PURPA and individual company analysis for internal purpose. Model development such as the Standard Load Flow Model, Georgia Power Cost of Service Model, and CSSM (Cost of Service Simulation Model). Manage the department's Issue File. Training of departmental employees, operating company personnel, and representatives of the Commission.

Senior Engineer:

Coordinator for Rate Case filings. Liaison between operating company and rate department. Internal analysis for operating companies and more development of those responsibilities listed under Engineer. Testified as cost expert in rate cases.

Supervisor:

Provided economic research and cost of service capability to Gulf Power and Mississippi Power Companies to support retail and wholesale rate filings and other regulatory requirements, and to provide management with pertinent information relative to their rate and regulatory affairs. This position was responsible for supervising the planning, development, evaluation, and formulation of effective economic analysis and related studies to present to internal management or to regulatory agencies, and to marketing for development marketing strategies.

Professional Papers:

"Room for Fixed Billing in the World of Conservation?" *Natural Gas and Electricity,* August, 2008.

"Are We On the Yellow Brick Road to the Land of Oz? The Wisdom of Rate Cases Today," EUCI, November 7, 2007.

"An Analysis of the Effects of Renewable Portfolio Standards on Retail Electricity Prices," presented in a webinar on 12/7/07 and EUCI Conference *Rate Case Essentials*, 11/7/07.

"Do You Want to Increase Your Utility's Demand Response and Consider it as a Bigger Player in Resource Planning," Energy Central, August 10 and August 17, 2007.

"Building a Risky Business," *Public Utilities Fortnight,* March, 2007.

"The Fixed Bill: Newborn Becomes Toddler!" Energy Central's EnergyPulse.net, January 3 and January 11, 2005, Cybertech, Inc.

"Building a Better Pricing System," *Public Utilities Fortnightly*, May 2004.

"Demand Response: Not Just Rhetoric, It Can Truly Be the Silver Bullet," *The Electricity Journal*, Vol. 16, Issue 10, pp. 48-60, December 2003.

"How to Perform Efficient TOU Design," *Energy Central's EnergyPulse.net*, July 23, 2003, *CyberTech, Inc.*

"Who's Afraid of the Fixed-Bill?," *Energy Central's EnergyPulse.net,* April 2003, *CyberTech, Inc.*

"Is Real-Time Pricing a Panacea? If So, Why Isn't It More Widespread?," *The Electricity Journal*, December, 2002.

"Flat Prices for Peak Hedging," *Public Utilities Fortnightly*, November 1, 2002.

"RTP Customer Demand Response – Empirical Evidence on How Much Can You Expect," in *Electricity Pricing in the Transition,* A. Faruqui and K. Eakin, eds., Kluwer Academic Publishers, 2002 (with Michael O'Sheasy).

"Flat Bills, Peak Satisfaction," *Energy Customer Management*, January/February, 2002.

"The New Pricing Organization," EPRI International Pricing Conference, co-authored with Robert Camfield, 2000.

"Roll the Dice, Set a Price," *Public Utilities Fortnightly*, May 15, 1999.

"5-cent Sundays....The Future of Electricity Prices?" *Electric Perspectives*, January/February 1999.

"Real-Time Pricing – Supplanted by Price-Risk Derivatives," *Public Utilities Fortnightly*, March 1, 1997.

"Customers Can Buy Low, Sell High," *The Electricity Journal*, February 1998.

"Real-Time Pricing for Purchased Electricity: An Innovative Pricing Option for Electricity as Used by the Pulp and Paper Industry," TAPPI Journal, April 1996.

"Reaping the Benefits of RTP: Georgia Power's RTP Evaluation Case Study," Volumes 1 and 2, Electric Power Research Institute (EPRI), December 1995.

Speeches and Presentations:

"Formulary Based Ratemaking for Retail Application," cost of service workshop, October 2008, Electricity–A Rising Cost Industry, EUCI.

"Rate Design Tools, Hedging, and the Proper Price Signal," rate design workshop, February, 2008, Managing Electric Price Volatility, EUCI.

"Will Renewable Portfolio Standards Increase Rates?" December 2007, EUCI webinar.

"Cost of Service – Are We Doing It Right?" "Providing the Customers Ultimate Bill Security – Fixed Bill," rate design workshop, cost-of-service workshop, November 2007, Rate Case Essentials, EUCI.

"Dynamic and Innovative Pricing of Electricity," Electricity Pricing in Continuously Changing Environments, EUCI, February 2007.

"Lets Examine How It's Been Done for one of our Industry's Most Risky Products – Fixed Bill," cost of service workshop, October 2006, Rate Case 101 – How to Produce a Successful Case, EUCI.

"Why Perform a Cost of Service Study? What Value does it bring to a Rate Case? What are its Limitations?" "How Can You Obtain Regulatory Approval for Innovative and Novel Rate Designs that Possess Little Industry Exposure?" Cost of Service Workshop, May 2006, Rate Case 101–How to Produce a Successful Rate Case, EUCI.

"How to Obtain Approval for a Novel, Innovative but Risky Pricing Product like Fixed Bill," Witness Preparation Workshop, November 2005, Utility Rate Case Management, INFOCAST.

"How Can You Obtain Internal and Regulatory Approval for Innovative and Novel Rate Designs that Possess Little Industry Exposure?," Cost-of -Service Workshop, October 2005, "Rate Case 101-How to Produce a Successful Case," EUCI.

"How to Obtain Regulatory Approval for Fixed Bill Type Products," Cost-of-Service Workshop, April 2005, *Rate Case 101: How to Produce a Successful Case*, EUCI.

"The Fixed Bill: Innovative Energy, Innovative Rate Option," April 2005, Developing New Products and Services for Utilities, EUCI.

"Digging In—Getting a Fixed-Bill Product Approved and Marketed," "Are There Any New Silver Bullets or Have We Used the Last One?," September 2004, Innovative Products and Services for the Energy Industry.

"Analyze This! The Fixed Bill Case," Successful Retail Products from the People Who Made Them, August 2004.

"Real Time Pricing Coupled with Risk Management at Georgia Power Company. It Keeps on Going and Going!" Peak Load Management Alliance, April 2005, PLMA.

"Introducing Fixed Bill," June 2004, UCI National Conference.

"Real-Time Pricing, Do Customers Really Price Respond?" April 2004, E Source 6th Annual Large C&I Summit.

"Fixed Bill," November 2003, E Source Annual Summit.

"A Summary of the Why's and How's of Real-Time Pricing," October 2003, GAO.

"The Fantastic Fixed Bill," October 2003, EMAC's 2003, Chartwell's 6th International Energy Marketing and Customer Service Conference Expo.

"The Electricity Business Needs A New Sheriff to Keep Law and Order and Maintain Peace; and Here's His Silver Bullet," October 2003, American Bar Association, Section of Environment, Energy, and Resources, 11th Section Fall Meeting.

"The Need for Demand Response and Critical Peak Pricing," September 2003, Gulf Power Company's 3rd Annual Price Responsive Load Management Conference.

"The Fixed Bill: Innovative Energy, Innovative Rate Option," June 2003, EUCI.

"The Flat Bill Phenomenon," May 2003, Edison Electric Institute/American Gas Association Customer Service Conference and Exposition.

"Fixed Bill Product in an Uncertain Market," and Comments on Demand Response Versus Product Pricing of Electricity, May 2003, AESP/EPRI Pricing Conference.

"Financial Folly or Smart Pricing, Fixed-Bill Options for the Energy Business," April 2003, Energy Central Web Cast.

"The Dollars and Sense of Fixed Bills in a Volatile Wholesale Market," April 2003, EUCI, *Connecting Wholesale and Retail Electricity Markets*.

"Flat Billing—Will It Take the Country by Storm?" February 2003, AESP Brown Bag Seminar.

"Selected Demand Response Programs," October 2002, Committee on Regional Electric Power Cooperation, Vancouver, British Columbia.

"Existing Dynamic Pricing Programs: Lessons Learned and Best Practices," August 2002, *Time-Sensitive Pricing for a Competitive Electricity Marketplace*, NYSERDA.

"Amend Response—A Vital Element of Competitive Markets," July 2002, EEI, *Market Design and Transmission Pricing School.*

"Successful Demand Response Products for Competitive Markets: They Really Work!" May 2002, *New Developments in Electric Market Restructuring* Sponsored by U.S. Association of Energy Economics and the International Energy and Environment Program.

"Customer Pricing Research and Its Critical Role in Designing Pricing—Products for a Regulated Utility," April 2002, American Marketing Association.

"The Price Builder's Workshop,"—Instructor, December 2001, EPRI.

"Innovative Pricing and Load Response: A California Energy Commission Proposal for Giving the Customer a Seat at the Table!" September 2001, International Facility Management Association's World Workplace 2001.

"Real-Time Pricing—How it Works, Benefits and Risks," September 2001, The Center for Business Intelligence, *Pricing in Electric Markets.*

"Real-Time Pricing Overview," June 2001, EMF Workshop on Retail Participation in Competitive Power Markets, Stamford University.

"Real-Time Pricing: Offering Incentives, Caps and Collars," March 2001, Infocast, *Retail Pricing for Competitive Power Markets.*

"Retail Pricing For Competitive Markets,"—Instructor, February 2001, Infocast.

"Real-Time Pricing and Resultant Load Management," November 2000, E-Source, *Energy for a New Era.*

"The Fundamentals of Unbundled Pricing,"—Instructor, September 2000, Infocast.

"Retail Pricing for Competitive Power Markets,"—Instructor, September 2000, Infocast/EPRI.

"International Energy Pricing Conference 2000,"—Program Advisor and Speaker, July 2000, EPRI.

"Pricing in Competitive Markets: Will Customers Accept 'Real-Time' Risks?" November 1999, E-Source, *Dynasties, Dinosaurs, and Dynamos: Energy Services in the 21st Century.*

"Cost of Service and Rate Design Workshop," August 1999, Tenega Nasional Berhad, Kuala Lumpur, Malaysia.

"Retail Pricing: Innovative, Proactive, Value-Based Pricing Strategies for the Competitive Era,"—Instructor, June 1999, Infocast.

"How to Buy Low and Sell High or Why is RTP so Popular?" June 1998, EPRI Fifth Biannual Innovative Pricing Conference.

"Innovative Rate Design," July 1997, *Training Programme for IAS Officers on Public Policy Analysis*, Indian Institute of Management, Ahmedabad, India.

Testimony

Docket No. 25060-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on Cost of Service.

Docket No. 010949-EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on Cost of Service.

Docket No. 881167-EI before the Florida Public Service Commission on behalf of Gulf Power Company as their expert witness on Cost of Service.

Docket No. 4147-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Case No. 2006-00045 Commonwealth of Kentucky before the Public Service Commission on behalf of East Kentucky Electric Cooperative as their expert witness on rate design.

Docket No. 050078-EI before the Florida Public Service Commission on behalf of the Commercial Group as their expert witness on cost of service and rate design.

Docket No. 16896-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Cause No. PUD 200500151 before the Corporation Commission of the State of Oklahoma on behalf of Oklahoma Gas and Electric as their expert witness on rate design.

Case No. 2004 Commonwealth of Kentucky before the Public Service Commission on behalf of East Kentucky Electric Cooperative as their expert witness on rate design.

Docket No. 4132-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 4755-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 11708-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 13140-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

Docket No. 16896-U before the Georgia Public Service Commission on behalf of Georgia Power Company as their expert witness on rate design.

MTO2

BARBADOS

THE FAIR TRADING COMMISSION

IN THE MATTER of the Utilities Regulation Act, Cap 282 of the Laws of Barbados;

IN THE MATTER of the Utilities Regulation (Procedural) Rules, 2003;

IN THE MATTER of the Application by The Barbados Light & Power Company Limited for a Review of Electricity Rates

EXHIBIT "MTO2"

This is a true copy of the Cost-of-Service report and study results marked Exhibit "**MTO2**" mentioned and referred to in paragraph 3 in the said Affidavit of Michael O'Sheasy.

SWORN TO by the deponent)
Michael O'Sheasy)
this 6 day of May 2009)
before me:

Michael O'Sheasy

____
NOTARY PUBLIC

I, C. J. Kell , Notary Public in and for the State of in the United States of America, do hereby DECLARE that on the day of May 6 2009, personally appeared before me a male person who identified himself to be the within named MICHAEL O'SHEASY and did in my presence sign and execute the Affidavit as and for his free and voluntary act and deed.

IN TESTIMONY WHEREOF I have hereunto subscribed my name and affixed my seal of office this 6 day of May , 2009.

Notary Public

C. J. KELL
NOTARY
EXPIRES
GEORGIA
July 8, 2012
PUBLIC
CHEROKEE COUNTY

EXHIBIT "MTO2"

COST-OF-SERVICE REPORT

THE BARBADOS LIGHT & POWER COMPANY LIMITED

TEST YEAR 2008

Prepared by

Christensen Associates Energy Consulting

April 2009

EXECUTIVE SUMMARY

1. In April 2007, Christensen Associates Energy Consulting (CAEC) was retained by Barbados Light & Power Company (BLPC) to prepare a cost-of-service (COS) study. Numerous meetings were held between BLPC and CAEC personnel to explore the prevailing circumstances and environment in Barbados to decide upon the best means to conduct such a study. Load research samples were drawn and resultant load data were analyzed. Financial data and supporting work reports were provided by BLPC to CAEC for the historic test year 2008. The study was prepared to conform to sound and accepted cost of service principles applied by the regulatory authorities within the electricity industry in the U.S.A.

2. This report explains what a COS study is, how to conduct such a study, and how this particular COS study was prepared. Allocations are made based upon the theory of cost causation. A copy of the Cost-of-Service study is enclosed. The overall results can be viewed in Schedule 1.

WHAT IS A COST-OF-SERVICE STUDY AND ITS TRADITIONAL USE IN REGULATORY PROCEEDINGS?

3. A cost-of-service study is first a compilation of a utility's total electric investments, revenues, and expenses that are used and useful in providing electricity. It also divides these costs among rate classes. It performs this division of costs among rate groups by allocating or directly assigning the Company's revenues, investments, and expenses among the various rate groups served by the Company. This division is based upon the causative nature of the costs incurred. The Federal Energy Regulatory Commission (FERC) of the United States indicates that a guiding principle is that the allocation must reflect cost causation. *See, e.g., Kentucky Utilities Co., Opinion No. 116-A, 15 FERC 61,222, p. 61,504 (1983); Utah Power & Light Co., Opinion No. 113, 14 FERC 61,162, p. 61, 298 (1981).* The results of the COS study will reveal the rate of return being earned by BLPC on the different rate groups that are served by the Company.

4. A cost-of-service study is traditionally used as the primary tool to determine the cost of providing electricity based upon costs authorized by the regulatory body. The COS reveals how well overall costs are being covered for the regulated utility as well as individual cost coverage by specific rates serving customers or groups of customers.

5. BLPC, like many other electric utilities, maintains its books and records in accordance with "International Financial Accounting Standards" under the historic convention which are generally considered to be sound accounting principles. This system of recording does not separate the Company's investments, revenues, and expenses by rate groups. Hence, the cost-of-service study conducted for BLPC accomplishes this objective.

6. Since a goal of a cost-of-service study is to identify what costs are incurred to provide service to certain groups of customers, such a COS can be a useful (and often times the primary) tool for determining the adequacy of current rates. For those rates which the cost-of-service study reveals as inadequate at current rate levels, the cost-of-service study is an appropriate tool for determining what rate changes should be made. The National Association of Regulatory Utility Commissioners (NARUC) in the United States identifies the cost-of-service study as among the basic tools of ratemaking, and it is used to attribute costs to different categories of customers based on how those customers cause costs to be incurred.[1]

GUIDING PRINCIPLES AND OBJECTIVES FOR COST OF SERVICE

7. The overall objective is to assign or allocate costs fairly and equitably to all rate groups of customers. This objective is accomplished when the resulting COS study reflects "cost causation," *i.e.*, those rate groups who caused a particular cost to be incurred by the Company in providing them service should be responsible for those costs.

8. When certain costs are readily identified with a particular rate group, the assignment of those costs to that rate group clearly reflects cost

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[1] *ELECTRICITY UTILITY COST ALLOCATION MANUAL*, January 1992, NATIONAL ASSOCIATION OF REGULATORY UTILITY COMMISONERS.

causation, and is fair and equitable to all customers. However, it must be recognized that most parts of an electric system are planned, designed, constructed, operated, and maintained to serve all customers. Indeed most of BLPC's costs have been incurred to serve all customers and rate groups, and these costs are referred to as joint or common costs. Joint or common costs must be allocated to customer groups based on the nature of the costs incurred, and the aggregate requirements and service characteristics of the customers that caused the costs to be incurred. The industry over time has developed a number of standard allocation methods that are generally agreed-to as reasonable. By adhering to this fundamental and essential principle of cost causation and thereby using appropriate allocators, the results of the cost-of-service study will be fair and equitable.

MAJOR DRIVERS IN COST CAUSATION

9. There are three primary drivers in causing cost to be incurred by an electric utility and are categorized into 3 respective components: (1) demand-related component based upon peak demands (kWs), (2) energy-related component based upon kilowatt hours (kWhs), and (3) customer-related component based upon number of customers. Some costs are incurred to meet peak demands, i.e., the highest quantity of electricity required over a specified short time interval. Other costs are incurred to provide the total quantity of electricity (energy measured in kWh) requested over a long time interval, usually a year. Still other costs are driven by the number of customers served by the Company (i.e. the fact that that a customer is simply requesting to be served or *hooked up* to the electric system). Each of these three drivers has its own separate and appropriate allocators to spread its respective costs to the associated rate groups and jurisdiction.

HOW A COST-OF-SERVICE ANALYSIS IS PERFORMED

10. The utility company's financial data are compiled and analyzed to determine how rate groups of customers influence the actual incurrence of cost by the utility. This review discloses certain direct costs that should be directly assigned to the specific rate group for which these costs were directly incurred. However, as previously mentioned, the majority of costs is incurred to perform a common function within the electric system for

various rate groups, and therefore must be allocated to the various rate groups.

11. The utility's financial costs are in general at too high an aggregate level of detail to allocate accurately to rate groups. Therefore, the data must be divided into smaller components, small enough to apply appropriate cost-based allocators. Therefore the financial data will be divided into the functional service that they provide and next into their respective service level. The final task is to sub-divide these costs into their cost-causative component (i.e. the three cost drivers: demand component, energy component, and customer component). This task is often referred to as "classification" of costs. An example of this division of costs into cost-causative components is substation transformers. Since substation transformers are normally sized for maximum demand requirements, it is by general agreement in the profession that substation transformers be considered in the demand component.

12. Once costs have been analyzed to disclose their appropriate cost-causative component and level of service, the corresponding allocator can be applied to apportion these common costs to the area of responsibility. By eventually summing all of these allocated common costs along with the directly assigned costs by rate group and with revenues received, the rate of return for each rate group can be determined.

SUMMARY OF THE MAJOR STEPS THAT ARE REQUIRED TO PERFORM A COST-OF-SERVICE STUDY

13. Typically the electricity industry undertakes six fundamental steps when conducting a cost-of-service study. These steps are: (1) financial data compilation, (2) functionalization, (3) levelization, (4) classification, (5) assignment, and (6) allocation.

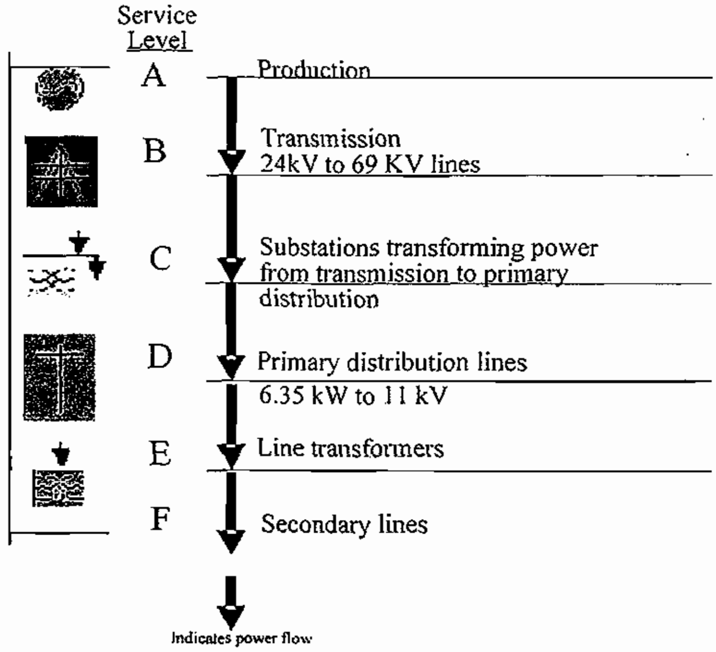
    (1) Financial data compilation is the process of gathering and compiling the revenue, expenses, and investment items that are *used and useful* in providing electric service for the test period. It is this data when divided among the customer groups that will enable parties to determine how well customer groups are covering the cost to serve them.

(2) Functionalization separates the investment and expenses of the Company into specific functions based on the operations involved in providing electric service. Those functions are production or generation, transmission, distribution, and general plant. General plant supports the three primary functions of production, transmission, and distribution, and also provides customer services (customer accounting, customer assistance, billing, etc.), and administrative and general (A&G).

(3) Levelization separates costs into service levels that are associated with producing electricity and delivering it to customers across the system. The service level designations are a means of identifying and associating investment and expenses with rate groups of customers and their loads at established points of service. In general, the lower the particular level of service required by the rate group, the greater is the cost of providing service since additional equipment is necessary to deliver service to lower levels of service. In addition there are more losses incurred in the delivery process for lower levels of service.

The following power flow diagram illustrates the paths on which electricity flows through the BLPC system. These paths are indicated on the chart by vertical lines. The horizontal lines identify the various levels of service that are necessary in providing electric service. These service levels enable the efficient allocation of costs to rate groups. The letter designations of service levels on the left side are a means of identifying the investment and expenses at these established points. These levels are referred to in the COS study on numerous occasions. This allows for the proper identification and association of system cost responsibility with the rate group's requirements to serve them at the respective service levels.

Service Level Designation and Power Flow Diagram



(4) Classification segregates costs into the three primary components of cost drivers based upon the "cost causative" characteristics for each account of the investment and expense elements within each function. As previously mentioned, these components are:

(a) Demand component: those costs that are incurred as a consequence of the magnitude of the load imposed on the system by customers over short intervals of time. This generally refers to costs experienced by the utility in order to provide the capacity necessary to serve the instantaneous peak load(s) throughout the year.

(b) Energy component: those costs that vary with the amount of energy consumed by the customer over long periods of time. This generally refers to costs such as fuel and variable operations and maintenance expenses which vary with the kilo Watt-hours (kWh) consumed by the customers.

(c) Customer component: those costs that vary with the number of customers on the system. This generally refers to the costs incurred by the utility to attach a customer to the distribution system and be ready to serve him or her, and for customer metering, customer billing, and certain administrative functions.

(5) Direct assignment is the association of specific cost and revenues with specific rate groups where cost causation can be directly identified with this specific rate group of customers.

(6) Allocation is the division of joint and common costs according to well-established rules for cost allocation by using allocators based upon cost causation.

14. The above steps were employed in the preparation of the Cost-of-Service Study for BLPC.

EXAMPLE OF THE IMPORTANCE OF PROPER CLASSIFICATION AND ALLOCATION

15. A meter is necessary to measure the amount of electricity provided to a customer. Within limits the meter can operate adequately regardless of the maximum demand and overall quantity of electricity requested. The cost of the meter incurred by the utility to serve the customer does not vary with quantity; rather, it is driven by the fact that each customer needs a meter. As a result, utilities will usually consider meters to be customer related, and therefore, allocate meter costs to a rate group upon an allocator which reflects the number of customers in these rate groups.

16. If meters were misclassified as kWh related, then the corresponding kWh allocator would spread more meter cost to large customers and less meter cost to small customers despite the fact that the large customers and the small customer in this example both required the same meter with related cost incurrence by the utility.

PURPOSE OF THE ALLOCATIONS AND HOW ALLOCATORS WERE DEVELOPED FOR THE COST-OF-SERVICE STUDY

17. In general there are two primary steps and purposes of the allocations: one is to allocate the financial costs to cost functional category and the other is to allocate the functional category costs to BLPC's five rate groups: Domestic, General Service, Secondary Voltage Power, Large Power, and Street Lighting. The cost functional categories can be observed in Schedules 5 and 6, as column headings. Sometimes mere direct assignments can be made if BLPC accounting records are separated to that degree. In most situations though, cost-causative allocators must be developed. BLPC provided analyses which often help to allocate to cost functional category. An example would be the division of investment in poles to distribution service levels D and F in which BLPC provided such an analysis of poles by service level. Allocators for the various accounts to cost functional category can be viewed in Schedules 9-13.

18. The development of allocators to rate group began with the collection and analysis of load research data. The process began with BLPC providing to me an enumeration of the utility's customers by rate and service level, along with their annual kWh. Christensen, under my supervision, developed a stratified random load research sample designed to meet industry standard statistical accuracy of 10 percent error at a 90 percent confidence level. BLPC then placed hourly interval data recorders on the resulting overall sample of 405 customers distributed by rate, providing hourly demands (kW) for the period of October 8, 2007 through July 1, 2008. These sample load data were then expanded to the rate group population using kWh-based sample expansion factors that were based on the original stratified sample designs. This produced hourly load shapes by rate. The load shapes for General Services ("GS") and Secondary Voltage Power ("SVP") were then apportioned to the two separate service levels to which they receive service on the basis of information provided by BLPC on the proportion of load for each respective rate that is served at each respective service level. Each rate group population's hourly values for the sampled period were then scaled to provide hourly load shapes for a 12-month 2008 time period. These

load shapes for the different service levels provided the ability to identify specific peak demands for each rate group for each month of the 2008 test year.

19. Next, the number of customers and their respective demand and energy sales by level of service were analyzed as was the supply including losses for annual system energy and demands. The demands of interest by rate group were at the time of the Company's monthly coincident peaks (MCP) or during the non-coincident individual rate peaks (NCP). Load flows were created and balanced at the various service levels.

20. This balancing of system load flows for demand and energy were developed through a load flow program, which computes total system losses for each service level. The load flow process begins by taking the total system energy sales at Level F (the secondary distribution lines level), multiplies these sales by the loss percentage at Level F, and then combines these calculated losses and sales. This amount is then added to the system sales at Level E, and this new total is in turn multiplied by the loss percentage at Level E. This procedure is continued up to Level A, the production level. Comparisons are made to the actual system loads by hour at the production level and the production level and the program then adjusts the loss percentages at each level and iterates the above process until the sum of the losses at each level matches the total system losses, and a balanced flow is produced. These total system loss percentages are then applied to the rate group's hourly loads and then *rolled-up* into the next respective service level by adding loads plus losses for each respective rate group. Loads plus losses become an allocator for that service level. This process calculates the demand allocators known as the "12-MCP," "3-MCP," "NCP," and "energy" allocators along with the "number of customers" allocator (although there are no losses necessary for the "number of customers" allocator).

21. In some instances, an allocator is "mixed" and is created by combining a number of allocators into one aggregate allocator that best reflects how these costs are incurred. An example of this combining is the Salaries and Wages (S&W) allocator.

22. In the different schedules of the COS study, adjacent to the accounting description, is the identification of each allocator. The rationale and use of these allocators will be explained in the following section.

SOURCE OF FINANCIAL DATA FOR THE COS

23. The financial information for BLPC for the test year of 2008 was provided by Mr. Hutson Best, Chief Financial Officer of BLPC. These investment, revenue, and expense items were then assigned or allocated to rate group by me and my team of analysts.

HOW THE CAPITAL COSTS AND RELATED O&M FOR THE FOUR FUNCTIONS OF PRODUCTION, TRANSMISSION, DISTRIBUTION, AND GENERAL PLANT WERE ALLOCATED

24. Production investment/capital related costs, which are found at Level A, are first classified as demand related and then allocated using the 12-MCP. The 12-MCP demand is the sum of the highest kilowatt load for BLPC predicted to occur in each month of the test year divided by twelve. This concept incorporates the fact that BLPC's system is planned and operated for the purpose of meeting these demands for electricity every month of the year as well as the fact that the Company's system load shape is relatively consistent throughout the year. It also reflects a consideration for scheduled maintenance and unscheduled outages. Classification of all production plant as demand related is common although not universal and 12-MCP is one of the most common and popular allocation methodologies throughout the industry.

25. An embedded Cost-of-Service Study of BLPC was undertaken for the Fair Trading Commission by NERA Economic Consulting in 2006. In this study NERA used a technique called "Cap-Sub" to first classify investment/capital related costs of production to demand and energy. The energy cost classification is supposed to reflect costs which are incurred to provide cheaper energy. The residual is considered to be demand related.

26. Cap-Sub has some philosophical logic and appeal. It does make sense that some resources such as low-speed diesel units are selected today to enable lower energy costs. However, the implementation of such a methodology is complex, controversial, and a utility's planning constraints

and circumstances may change. Classification of production plant as all demand related and use of 12-MCP as the allocator for these costs has a solid rationale and traditional usage within the industry and Barbados. 12-MCP allocation of all production cost recognizes that generating requirements are sized to serve the maximum loads to be imposed upon the system throughout the year, maintenance requirements must be met, and it accommodates well the system's relatively consistent, flat load shape without significant seasonal patterns of usage. 12-MCP allocation is also relatively stable in its COS impacts over time, simple to administer, possesses sound philosophical logic, has been proven with widespread usage and acceptability over long periods of time, and aligns well with a flat fuel clause like the company's Fuel Adjustment Clause (FAC). Therefore, we selected 12-MCP as the allocator for production capital cost.

27. An examination was made of Cap-Sub splits into demand and energy components derived by NERA along with their use of 12-MCP for the allocation of the Cap-Sub demand cost and with an energy allocation for the residual energy piece of production. The conclusion is that if these Cap-Sub factors were applied to the present COS study, it would not create materially different earnings implications from the Company's COS study use of demand classification of all production and resultant 12-MCP allocation of all production. It appears that the biggest impact of NERA's Cap-Sub factors would be a decrease in the Domestic class's rate of return (ROR) which would then suggest a higher rate increase for Domestic than the BLPC COS study.

28. Production-related running costs are allocated on the basis of the customer's expected annual energy consumption, adjusted for losses. Fuel costs are directly identified on a rate group basis and are directly offset by fuel revenue since the costs and revenues associated with fuel are dealt with through the fuel clause adjustment.

29. Transmission-related capital costs, just as production-related and other costs, are allocated in the manner in which they are incurred. The transmission costs are incurred based upon the need for transmission capacity and occur at service level B. Transmission capacity in turn, is a function of system load requirements. The transmission function does not

have the same maintenance requirements and reserve requirements as the production function. If the transmission function can serve the few peak months of the year, it is then highly likely that it can serve the requirements of transmitting electricity during the remainder of the year. Therefore a 3-MCP allocator based upon the average of the coincident peaks for the three highest peak months of the year is used as the allocator for transmission. Transmission expenses were allocated in a similar manner similar to transmission capital cost.

30. Distribution-related capital costs are first segregated by levels of service C-F. Then these distribution costs by level are classified and divided between those costs which are specifically related to the number of customers served (customer costs) and those costs which are specifically related to load requirements (demand costs). Distribution customer-related costs are allocated based on the average number of customers. Distribution demand-related capital costs are allocated based on the rate groups' maximum demands, *i.e.*, non-coincident peak demands (NCP). The NCP demand for each retail rate class is the highest demand occurring for that rate class during the test year. This method was used to allocate distribution costs at voltage levels C through F using a separate NCP allocator for each respective level of service. The NCP concept is based upon the idea that certain costs are incurred on the basis of the rate groups' maximum use of the distribution system, *i.e.*, their maximum non-coincident demands rather than their demands during the system peaks. Distribution expenses were allocated in a similar manner similar to distribution capital cost.

31. General plant capital cost serves to support the primary functions of production, transmission, and distribution as well as to provide customer services. Therefore these costs are allocated based upon a composite of the functions it serves. This composite is referred to as "Salaries and Wages" (S&W). It is developed by weighting each function's O&M expenses by the relative amount of salaries and wages for each function that is served by general plant. Administrative and General (A&G) expenses are allocated based upon S&W unless they apply to a direct primary function in which case they are allocated in the manner of that primary function. For example property insurance related to the

production function will be allocated as production capital costs are allocated. Customer Services accounts are allocated upon the number of customers by rate group except where a direct rate group relationship is known and would be different thereby requiring a weighting of customers. The meter reading expense allocator provides an example of this weighting. It is developed considering each rate's degree of difficulty in reading the meter. Marketing, Human Resources, Information Systems, and Accounting expenses were allocated upon S&W except where a direct rate group linkage was provided by BLPC. For an example of direct linkage, Key Accounts expenses and Demand-Side Management expenses were provided by rate group and therefore directly assigned to those rate groups respective cost responsibility.

32. For a complete and specific listing of account allocations, please see the appropriate COS schedules for how each particular account was allocated.

OUTLINE OF COST-OF-SERVICE SCHEDULES

33. An index provides a listing of schedules and designates the major sections of the COS study. Schedule 1 presents, in summary form, the results of the cost-of-service study for the total system and by the five rate groups for the test period ended December 31, 2008. One can observe the earnings position under present rates and proposed rates for BLPC and each of the five rate groups. The parity ratios shown in Schedule 1 are the ratios of the rate groups' rates of return divided by BLPC's rate of return.

34. Schedule 2 provides definitions and abbreviations of cost functional categories and rate group definitions which are used in the COS along with the cost functional category allocators to rate group. Schedule 3 is a listing of allocators to rate group used in the COS study.

35. As previously mentioned, initial steps in the COS procedure include compilation of the financial data, functionalization and levelization of this data, and classification of the data into cost component. After costs have been placed into cost functional category, they can then be allocated to rate group. Starting from the back of these schedules and working forward, Schedules 9-13 list the individual expense and investment

accounts for the COS study and their allocators or assignment to function, level, cost classification, and later placement into cost functional category. These Schedules 9-13 feed Schedules 4-7 where the financial data are summed into the cost functional category totals for subsequent allocation to rate group. Schedule 8 provides detail of revenues by rate group. Schedule 7 is the allocation of income taxes to rate group. Schedule 6 reveals the compilation of the individual expense elements by cost functional category. Schedule 5 compiles the investment elements which make up Rate Base by cost functional category. Schedule 4 allocates the Rate Base and Expense cost functional categories to the five rate groups. The allocated results from Schedule 4 along with the revenues found in Schedule 8 and allocated income taxes in Schedule 7 then feed the Summary Page, Schedule 1.

36. Schedule 14 aggregates the resultant cost including the returns found in Schedule 1 for each rate group and breaks them down into the three cost categories of demand-related, energy-related and customer-related. It then takes these costs totals and divides by the rate groups respective billing determinants. This reveals unit costs by rate group and cost category within each rate group.

37. In order to evaluate the earnings of the rate groups in a COS study, it is necessary to properly consider the fact that fuel-related costs are recovered through the fuel clause adjustment. Fuel-related cost should therefore not affect earnings. Because there is often a timing imbalance between when fuel expenses are incurred and fuel revenues are received in a test period, it is sometimes necessary to make a fuel timing adjustment. The computation of this adjustment can be seen in Schedule 15 and the resultant adjustment shows up on Schedule 8.

SUMMARY AND CONCLUSIONS

38. This cost-of-service study is a reasonable and accurate reflection of the cost of serving BLPC's customers. Although there are other ways to allocate costs, BLPC's methodologies are sound, objective, and consistent with the methodologies used in numerous other cases throughout the industry. The results can be observed in the Summary Page (Schedule 1) of the study. This cost-of-service study can be used

as an excellent tool to assist in the evaluation of BLPC's earnings for the *various rate groups for the corresponding test period.*

Cost of Service Study Results

Index

Schedule 1

Summary Rate of Return Analysis

	System	Dom	GS	SVP	LP	SL	Footnotes
Revenues							
Retail Sales	$ 471,490,760	$ 144,259,713	$ 28,048,113	$ 176,609,616	$ 117,329,647	$ 5,243,671	(a)
Retail Sales less Fuel	**$ 198,801,101**	**$ 57,320,772**	**$ 12,803,940**	**$ 77,459,951**	**$ 48,980,178**	**$ 2,236,260**	(a)
Pole Rents	$ 1,351,967	$ 624,228	$ 93,717	$ 427,455	$ 176,645	$ 29,923	(b)
Other	$ 68,881	$ 19,861	$ 4,436	$ 26,838	$ 16,971	$ 775	(c)
Service Charges	$ 226,159	$ 189,094	$ 27,869	$ 8,851	$ 345	$ -	(d)
EIB Subsidy Refund	$ 569,900	$ 400,517	$ 91,780	$ 74,693	$ 2,911	$ -	(e)
Total Misc. Revenues	$ 2,216,907	$ 1,233,699	$ 217,802	$ 537,837	$ 196,872	$ 30,698	
Total Operating Revenue	$ *473,707,668*	$ *145,493,412*	$ *28,265,915*	$ *177,147,453*	$ *117,526,519*	$ 5,274,368	
Investment Income	$ 242,109	$ 69,808	$ 15,593	$ 94,334	$ 59,650	$ 2,723	(f)
Gain (Loss) on Exchange	$ 77,022	$ 22,208	$ 4,961	$ 30,011	$ 18,977	$ 866	(f)
Total Revenues	$ 474,026,799	$ 145,585,428	$ 28,286,469	$ 177,271,798	$ 117,605,146	$ 5,277,958	
Expenses							
Expenses Allocated to Rate Group	$ 441,330,004	$ 142,537,889	$ 26,930,353	$ 163,578,970	$ 102,466,695	$ 5,816,097	(g)
Income Tax Allocated to Rate Group	$ (356,854)	$ (1,098,470)	$ (161,110)	$ (129,648)	$ 1,182,298	$ (149,925)	(h)
Total Expenses Allocated to Rate Group	$ 440,973,150	$ 141,439,419	$ 26,769,243	$ 163,449,323	$ 103,648,993	$ 5,666,172	
Rate Base	$ 544,198,328	$ 160,900,046	$ 37,704,071	$ 225,852,843	$ 112,583,376	$ 7,157,992	(g)
Realized Returns	$ 33,053,648	$ 4,146,009	$ 1,517,226	$ 13,822,475	$ 13,956,153	$ (388,214)	(i)
Realized Rate of Return on Rate Base	6.07%	2.58%	4.02%	6.12%	12.40%	-5.42%	(j)
Target Rate of Return on Rate Base	10.48%	7.82%	9.00%	10.99%	14.42%	0.00%	(k)
Target Returns	57,031,500	12,582,384	3,393,366	24,821,227	16,234,523	0	(l)
Deficiency (Excess) in Revenue (new)	**$ 28,209,238**	**$ 9,925,147**	**$ 2,207,224**	**$ 12,939,709**	**$ 2,680,435**	**$ 456,722**	(m)
Increase in Misc. Revenues	**$ 220,000**	**$ 183,945**	**$ 27,110**	**$ 8,609**	**$ 336**	$ -	(k)
Net Deficiency in Sales Revenue	**$ 27,989,238**	**$ 9,741,202**	**$ 2,180,115**	**$ 12,931,099**	**$ 2,680,099**	**$ 456,722**	(n)
Target Total Revenue	$ 502,236,036	$ 155,510,575	$ 30,493,693	$ 190,211,506	$ 120,285,581	$ 5,734,681	(o)
Target Revenue from Sales	$ 499,479,998	$ 154,000,915	$ 30,228,228	$ 189,540,716	$ 120,009,746	$ 5,700,393	(p)
Change in Rates as % of Retail Sales less fuel	**14.08%**	**16.99%**	**17.03%**	**16.69%**	**5.47%**	**20.42%**	(q)
Current Rates Rate of Return Parity Ratio	100.0%	42.4%	66.3%	100.8%	204.1%	-89.3%	(r)
Proposed Rates Rate of Return Parity Ratio	100.0%	74.6%	85.9%	104.9%	137.6%	0.0%	(s)

Schedule 1
Summary Rate of Return Analysis
(Continued)

Footnotes:
(a) See Schedule 8
(b) Based on Gross Plant Poles
(c) Based on base revenue
(d) Based on customer numbers excluding lighting
(e) Allocated using the CS2 allocator provided by BLPC
(f) Allocated according to Retail Sales less fuel
(g) See Schedule 4
(h) See Schedule 7
(i) Revenues less expenses
(j) Realized returns divided by rate base
(k) Provided by BLPC
(l) Rate base times targeted rate of return
(m) Target returns plus related income taxes less realized returns
(n) Deficiency less increase in misc revenues
(o) Total current revenues plus Deficiency in Revenue
(p) Retail sales plus Net Deficiency in Sales Revenue
(q) Net Deficiency in Sales Revenue divided by retail sales less fuel
(r) Realized return for rate group divided by realized return overall
(s) Target return for rate group divided by target return overall

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Schedule 2
Definitions

	Full Name	Abbrev Name	Num Cust	MWh	Billing KW
	Domestic	Dom-F	98,396	300,978	
	GS Total	GS Total	14,502	52,774	
	SVP Total	*SVP Total*	*4,605*	*343,250*	*136,760*
	Large Power	LP-D	180	236,622	78,339
	Street Lighting	SL-F	0	10,411	
		Totals	117,683	944,036	215,099

Schedule 2
Definitions (Continued)

Cost Functional Categories

	Full Name	Abbrev
	Power Supply Demand at Generation	PS-DMND (A)
	Power Supply Energy at Generation	PS-ENRG (A)
	Transmission Demand	T-DMND (B)
	Distribution Substations	D-SUBS C
	Distribution Primary Lines	D-LINES (D)
	Line Transformers	D-TRANS (E)
	Distribution Lines -2ndry	D-LINES2 (F)
	Street Lighting	SL (G)
	Distribution - Other	DIST-O
	Services	SERV
	Meters	METERS
	Meter Reading	METER-R
	Billing & Accounting	BILLING
	Uncollectible	UNCOL
	Revenue Related	REVREL
	For Direct Assignment	DA
	Customer Service Cost	CS1
	Power Quality	CS2
	Fuel Costs	Fuel
	Income Tax	IncTax

Schedule 3

Allocators of Cost Functional Categories to Rate Group

Customer Class	12MCP-A	3MCP-B	1NCP-D	1NCP-E	1NCP-F	1 NCP-C	Energy A	Energy Metered	SL	CS1	Meter Reading	UnColl	CS2	Customer 4	Meters
Domestic Level F	22%	21%	33%	42%	68%	33%	32%	32%	0%	83%	82%	46%	70%	91%	49%
GS Levels E & F	7%	7%	6%	8%	8%	6%	5%	6%	0%	13%	13%	15%	16%	9%	12%
SVP Levels E& F	46%	47%	38%	48%	21%	38%	37%	36%	0%	4%	5%	39%	13%	0%	16%
Large Power - Level D	25%	26%	21%	0%	0%	21%	25%	25%	0%	0%	0%	0%	1%	0%	24%
Street Lighting - Level F	0%	0%	2%	2%	3%	2%	1%	1%	100%	0%	0%	0%	0%	0%	0%
Total	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000	1.000

Schedule 4

Rate Base and Expense Allocations of Cost Functional Categories to Rate Group

A) Allocation of Rate Base

	PS-DMND (A)	PS-ENRG (A)	T-DMND (B)	D-SUBS C	D-LINES (D)	D-TRANS (E)	D-LINES2 (F)	SL (G)	SERV	METERS	METER-R	UNCOL	DA	CS1	CS2	Fuel	Total
Total Rate Base	264,165,897	1,600,587	94,679,733	35,049,170	70,878,640	31,315,867	27,849,681	4,033,667	15,435,996	6,591,158	348,158	139,106	64,358	1,886,778	159,533	0	544,198,328

Customer Class Responsibility for Rate Base Components

Allocator	12MCP-A	Energy A	3MCP-B	1NCP-D	1NCP-D	1NCP-E	1NCP-F	SL	Customer 4	Meters	Meter Reading	UnColl	NA	CS1	CS2	Energy Metered		
Domestic Level F	57,533,002	513,570	19,864,069	8,278,119	23,425,603	13,145,935	18,815,964	-	14,037,794	3,241,704	286,363	63,557	13,515	1,570,333	112,117	-	160,900,046	29.57%
GS-1 Level F	11,397,686	54,458	4,063,714	977,139	2,764,894	1,551,731	2,321,014	-	1,398,203	513,524	29,566	14,220	719	162,170	17,363	-	25,066,402	4.61%
GS-2 Level E	6,701,207	32,300	2,410,387	579,589	1,639,993	920,407	-	-	-	246,322	14,182	6,821	345	77,788	8,329	-	12,637,670	2.32%
SVP-1 Level F	33,563,652	160,661	12,058,943	2,593,353	7,338,101	4,118,333	5,894,629	-	-	450,738	7,649	24,003	4,154	32,248	9,207	-	66,257,693	12.18%
SVP-2 Level E	89,148,321	426,686	35,037,816	6,887,787	19,489,548	10,938,042	-	-	-	572,867	9,721	30,506	11,171	40,924	11,702	-	159,595,151	29.33%
Large Power - Level D	65,920,029	394,878	24,254,802	5,339,274	15,079,610	-	-	-	-	1,565,983	677	-	34,453	2,854	815	-	112,383,376	20.69%
Street Lighting - Level F	-	18,033	-	403,908	1,142,890	641,420	918,073	4,033,667	-	-	-	-	-	-	-	-	7,157,992	1.32%
Total System	264,165,897	1,600,587	94,679,733	35,049,170	70,878,640	31,315,867	27,849,681	4,033,667	15,435,996	6,591,158	348,158	139,106	64,358	1,886,778	159,533	0	544,198,328	100.00%

B) Allocation of Expenses Excluding Income Taxes

	PS-DMND (A)	PS-ENRG (A)	T-DMND (B)	D-SUBS C	D-LINES (D)	D-TRANS (E)	D-LINES2 (F)	SL (G)	SERV	METERS	METER-R	UNCOL	DA	CS1	CS2	Fuel	Total
Total Expenses Excluding Income Taxes	70,197,065	12,804,693	6,820,698	5,369,149	14,555,791	7,362,111	8,624,954	1,633,157	2,047,001	1,695,029	1,379,296	551,095	514,861	7,530,880	632,022	297,612,203	441,330,004

Customer Class Responsibility for Expenses

Allocator	12MCP-A	Energy A	3MCP-B	1NCP-D	1NCP-D	1NCP-E	1NCP-F	SL	Customer 4	Meters	Meter Reading	UnColl	NA	CS1	CS2	Energy Metered		
Domestic Level F	15,388,302	4,108,562	1,850,607	1,774,368	4,810,322	3,090,505	5,827,242	-	1,861,582	833,660	1,134,483	251,793	108,124	6,269,438	444,175	94,884,748	142,537,889	32.30%
GS-1 Level F	3,002,145	435,663	378,590	209,444	567,805	364,799	687,841	-	185,419	132,062	117,830	56,334	5,753	647,288	68,788	10,330,445	17,169,505	3.89%
GS-2 Level E	1,780,718	238,400	224,560	134,232	334,793	216,380	-	-	-	63,346	56,184	27,022	2,759	310,484	32,996	6,326,974	9,760,848	2.21%
SVP-1 Level F	8,919,434	1,285,290	1,123,454	555,871	1,506,968	968,187	1,825,547	-	-	115,920	30,304	95,093	33,235	128,715	36,477	28,845,308	45,469,803	10.30%
SVP-2 Level E	23,689,471	3,413,486	2,983,824	1,476,358	4,002,416	2,571,446	-	-	-	147,323	38,514	120,854	89,367	163,583	46,358	79,366,167	118,109,167	26.76%
Large Power - Level D	17,416,994	3,159,024	2,259,663	1,142,300	3,096,782	-	-	-	-	402,719	2,682	-	275,623	11,392	3,228	74,596,287	102,466,695	23.22%
Street Lighting - Level F	-	144,268	-	86,575	234,706	150,793	284,324	1,633,157	-	-	-	-	-	-	-	3,282,274	5,816,097	1.32%
Total System	70,197,065	12,804,693	6,820,698	5,369,149	14,555,791	7,362,111	8,624,954	1,633,157	2,047,001	1,695,029	1,379,296	551,095	514,861	7,530,880	632,022	297,612,203	441,330,004	100.00%

Schedule 5

Total Rate Base by Cost Functional Category

	PS-DMND (A)	PS-ENRG (A)	T-DMND (B)	D-SUBS C	D-LINES (D)	D-TRANS (E)	D-LINES2 (F)	SL (G)	SERV	METERS	METER-R	UNCOL	DA	CS1	CS2	Total
A) Net Total Plant																
Cost of Plant	499,800,354	0	125,155,629	42,385,876	110,050,264	51,543,751	55,791,275	10,512,679	26,968,219	12,784,976	366,776	146,545	0	1,973,054	168,064	937,647,461
Accumulated Depreciation	(257,583,960)	0	(34,480,700)	(18,488,013)	(40,837,786)	(21,148,500)	(28,174,294)	(6,702,435)	(11,854,745)	(6,410,928)	(183,184)	(73,191)	0	(985,429)	(83,939)	(427,007,104)
Total	242,216,394	0	90,674,928	23,897,863	69,212,478	30,395,251	27,616,981	3,810,244	15,113,474	6,374,048	183,592	73,354	0	987,625	84,126	510,640,357
B) CWIP																
Total	513,377	0	2,385,164	445,344	679,625	58,239	73,292	0	0	12,294	3,524	1,408	0	18,956	1,615	4,192,837
C) Current Asset and Liability Adj.																
Cash Working Capital	6,306,927	1,600,587	539,254	455,340	1,131,878	560,449	681,644	125,119	70,343	123,273	168,507	67,327	64,358	920,354	77,213	12,892,572
Customer Contributions	0	0	0	0	(817,342)	0	(817,342)	0	0	0	0	0	0	0	0	(1,634,684)
Materials & Supplies	25,301,135	0	3,627,552	1,113,260	2,911,744	1,350,947	1,430,569	312,258	801,037	341,744	0	0	0	0	0	37,190,246
LESS Deferred Charges & Credits	(10,171,936)	0	(2,547,167)	(862,637)	(2,239,743)	(1,049,018)	(1,135,464)	(213,954)	(548,857)	(260,200)	(7,465)	(2,982)	0	(40,156)	(3,420)	(19,083,000)
Total	21,436,126	1,600,587	1,619,639	705,963	986,537	862,378	159,407	223,423	322,522	204,817	161,043	64,344	64,358	880,198	73,793	29,365,134
Total Rate Base	264,165,897	1,600,587	94,679,732	25,049,170	70,878,640	31,315,867	27,849,681	4,033,667	15,435,996	6,591,158	348,158	139,106	64,358	1,886,778	159,533	544,198,328

Schedule 6

Total Expenses by Cost Functional Category

	PS-DMND (A)	PS-ENRG (A)	T-DMND (B)	D-SUBS C	D-LINES (D)	D-TRANS (E)	D-LINES2 (F)	SL (G)	SERV	METERS	METER-R	UNCOL	DA	CS1	CS2	Fuel	IncTax	Total
Operating & Maintenance Expenses (inc. Fuel)	50,455,419	12,804,693	4,314,036	3,642,716	9,055,025	4,483,596	5,453,151	1,000,952	562,740	986,183	1,348,057	538,614	514,861	7,362,830	617,708	297,612,203	0	400,752,783
Depreciation	18,000,673	0	4,133,671	1,561,166	5,078,863	2,676,580	2,942,516	603,428	1,410,438	661,007	26,554	10,610	0	142,846	12,168	0	0	37,260,519
Taxes Other Than Income	1,740,973	0	372,991	165,266	421,903	201,935	229,288	28,777	73,822	47,840	4,685	1,872	0	25,203	2,147	0	0	3,316,702
																		0
Income tax																	(356,854)	(356,854)
Total Expenses	70,197,065	12,804,693	8,820,698	5,369,149	14,555,791	7,362,111	8,624,954	1,633,157	2,047,001	1,695,029	1,379,296	551,095	514,861	7,530,880	632,022	297,612,203	(356,854)	440,973,150

Schedule 7

Income Tax Allocation to Rate Group

Reference		Item		System	Dom	GS	SVP	LP	SL
	Revenues								
		Base revenue	198,801,101						
		Fuel Revenue	272,291,548						
		Fuel Revenue Timing Adjustment	398,112						
		Misc Revenue	2,216,907						
		Investment Income	242,109						
		Gain (Loss) on Exchange	77,022						
See Schedule 8		Total	474,026,799	474,026,799	145,585,428	28,286,469	177,271,798	117,605,146	5,277,958
	Expenses								
		Fuel	297,612,203						
		Operating and maintenance	103,140,580						
		Taxes,other than on income	3,316,702						
		Provision for depreciation	37,260,519						
		(Gain)/loss on exchange							
See Schedule 4		**Total (less interest)**	441,330,004		142,537,889	26,930,353	163,578,970	102,466,695	5,816,097
Allocated using rate group responsibility for rate base (See Schedule4)		Interest During Construction	(1,770,851)		(523,578)	(122,691)	(734,937)	(366,352)	(23,292)
		Long Term & Other Interest	8,072,478		2,386,744	559,291	3,350,235	1,670,029	106,180
		Total	447,631,631		144,401,055	27,366,953	166,194,267	103,770,371	5,898,984
	R =	**Taxable Income**	26,395,167		1,184,373	919,516	11,077,530	13,834,775	(621,026)
	Corporation Taxes								
		Current Portion	0						
		Deferred Portion	(1,204,703)						
		Deferred ITC	(1,195,962)						
		Deferred MTC	2,043,811						
	T =	Income Tax	(356,854)						
	C = Tax rate		15%						
	RC		3,959,275						
	(RC-T)/ratebase		0.0079311694						
	Net Tax		(356,854)						
					Dom	**GS**	**SVP**	**LP**	**SL**
See Schedule 4	Rate Base to Tariff			544,198,328	160,900,046	37,704,071	225,852,843	112,583,376	7,157,992
	Taxes via R*C-K*I allocator		Total		(1,098,470)	(161,110)	(129,648)	1,182,298	(149,925)

Schedule 8
Revenues by Rate Group

		Assignment	Dom	GS Total	SVP Total	LP	SL
Domestic	$ 57,320,772	Direct	$ 57,320,772				
GS	$ 12,803,940	Direct		$ 12,803,940			
SVP	$ 77,459,951	Direct			$ 77,459,951		
Large Power	$ 48,980,178	Direct				$ 48,980,178	
Street Lighting	$ 2,236,260	Direct					$ 2,236,260
Fuel Revenues	$ 272,291,548	Energy Metered	$ 86,812,015	$ 15,221,918	$ 99,004,912	$ 68,249,683	$ 3,003,020
Fuel Revenues Timing Adjustment	$ 398,112	Energy Metered	$ 126,926	$ 22,256	$ 144,753	$ 99,786	$ 4,391
Adjusted Fuel Revenues	$ 272,689,660		$ 86,938,941	$ 15,244,174	$ 99,149,665	$ 68,349,469	$ 3,007,411
Total Sales Related Revenues	$ 471,490,760		$ 144,259,713	$ 28,048,113	$ 176,609,616	$ 117,329,647	$ 5,243,671
		Allocator	**Dom**	**GS Total**	**SVP Total**	**LP**	**SL**
Pole Rents	$ 1,351,967	Based on Gross Plant Poles	$ 624,228	$ 93,717	$ 427,455	$ 176,645	$ 29,923
Other	$ 68,881	Base Revenue	$ 19,861	$ 4,436	$ 26,838	$ 16,971	$ 775
Service Charges	$ 226,159	All customers except lighting	$ 189,094	$ 27,869	$ 8,851	$ 345	$ -
EIB Subsidy Refund	$ 569,900	CS2	$ 400,517	$ 91,780	$ 74,693	$ 2,911	$ -
Total Non-Sales Revenues	$ 2,216,907		$ 1,233,699	$ 217,802	$ 537,837	$ 196,872	$ 30,698
Total Sales and Non-Sales Revenues	$ 473,707,668		$ 145,493,412	$ 28,265,915	$ 177,147,453	$ 117,526,519	$ 5,274,368
Investment Income	$ 242,109	Base Revenue	$ 69,808	$ 15,593	$ 94,334	$ 59,650	$ 2,723
Gain (Loss) on Exchange	$ 77,022	Base Revenue	$ 22,208	$ 4,961	$ 30,011	$ 18,977	$ 866
Total Revenues	$ 474,026,799		$ 145,585,428	$ 28,286,469	$ 177,271,798	$ 117,605,146	$ 5,277,958

Schedule 9
O&M Expense Detail

GENERATION EXPENSES (1,000s)		
	Allocation	**$Total**
Generation Fuel Expenses		
Bunker C fuel		180,289
Natural Gas		563
Diesel Fuel		55,844
Av-Jet fuel		55,971
Purchased Power -Fuel		4,945
Total Fuel	Fuel	297,612
Generation O&M		
Superintendence	PS-DMND (A)	6,631
Operators wages	PS-DMND (A)	4,159
General Workers wages		0
Water	PS-ENRG (A)	986
Lubricants	PS-ENRG (A)	3,052
Production Supplies	PS-ENRG (A)	67
Station Cleaning	PS-ENRG (A)	575
Obsolete Stock	PS-DMND (A)	1,348
Ash Handling	PS-DMND (A)	259
Maint. of Common Facilities	PS-DMND (A)	1,151
Misc. Power Expenses		0
Maintenance of Lands/Buildings	PS-DMND (A)	272
Maintenance of Boiler Plant	70% PS-DMND (A) 30% PS-ENRG (A)	1,529
Maint. of Prime movers_accesor	70% PS-DMND (A) 30% PS-ENRG (A)	21,025
Maintenance of Generators	70% PS-DMND (A) 30% PS-ENRG (A)	142
Maint. of Electrical Plant	70% PS-DMND (A) 30% PS-ENRG (A)	1,934
Maint.Misc.Power Plant	70% PS-DMND (A) 30% PS-ENRG (A)	2,127
Maintenance of Instrumentation	70% PS-DMND (A) 30% PS-ENRG (A)	326
Breakdown contingency		0
Subsurface Oil Recovery	PS-DMND (A)	16
Safety	PS-DMND (A)	166
Security	PS-DMND (A)	348
Generation Welfare		0
Training	PS-DMND (A)	236
Generation Tools		0
Studies	PS-DMND (A)	401
System Planning	PS-DMND (A)	353
Total Generation O&M		47,105
Total Generation Fuel and O&M		344,717

Schedule 9 (continued)

O&M Expense Detail

TRANSMISSION AND DISTRIBUTION EXPENSES (1,000s)		
Distribution Superintendence	Allocation based on data provided by BLPC	2,440
Training	Allocation based on data provided by BLPC	500
Maint. of Substation Buildings	Allocation based on data provided by BLPC	179
Maint. Substation Equipment	Allocation based on data provided by BLPC	553
Maintenance of Overhead Lines	Allocation based on data provided by BLPC	1,888
SCADA Expenses	Allocation based on data provided by BLPC	1,327
Maintenance of Underground Sys	D-LINES (D)	602
Maintenance of Street Lighting	SL (G)	480
Trouble Call Expenses	Allocation based on data provided by BLPC	1,551
Maintenance of Transformers	D-TRANS (E)	608
Maintenance of Meters	METERS	394
Damage to Customer premises		
To Domestic	DA	87
To GS F	DA	6
To GS E	DA	3
To SVP F	DA	0
To SVP E	DA	1
Nonassignable	CS1	111
Maintenance of Plant Records	Allocation based on data provided by BLPC	444
Distribution Welfare		0
Motor Transport		0
System Planning	Allocation based on data provided by BLPC	25
Service Planning	Allocation based on data provided by BLPC	265
Drawing Office	D-SUBS C	272
Distribution Tools		0
Studies		0
Total Distribution Expenses		11,738
CUSTOMER SERVICES EXPENSES (1,000s)		
Customer Services Supervision	CS1	1,710
Meter Reading	METER-R	1,247
City Office - Collections	CS1	1,608
Uncollectible bills	UNCOL	498
Billings	CS1	726
Garrison Office - Collections	CS1	619
Customer Accounts	CS1	363
Customers Information	CS1	565
Studies	CS1	4
Reconnection Disconnection	CS1	537
Training	CS1	45
Inspections	CS1	532
Marketing		0
Power Quality Assurance	CS2	571
Total Customer Services Expenses		9,025

Schedule 9 (continued)

O&M Expense Detail

INFORMATION SYSTEMS EXPENSES (1,000s)		
IS Supervision	Allocated as Salaries and Wages	396
IS System Maintenance	Allocated as Salaries and Wages	1,075
IS System Operations	Allocated as Salaries and Wages	750
Training	Allocated as Salaries and Wages	110
IS Software Licences	Allocated as Salaries and Wages	775
IS Hardware Maintenance	Allocated as Salaries and Wages	322
IS Supplies	Allocated as Salaries and Wages	44
Mapping/Website maintenance	Allocated as Salaries and Wages	275
Studies	Allocated as Salaries and Wages	2
Total Information Systems Expenses		3,749
ACCOUNTING EXPENSES (1,000s)		
Accounts Supervision	Allocated as Salaries and Wages	760
Financial Accounting	Allocated as Salaries and Wages	408
Treasury Accounting	Allocated as Salaries and Wages	656
Management Accounting	Allocated as Salaries and Wages	279
Internal Audit	Allocated as Salaries and Wages	244
Audit Fee	Allocated as Salaries and Wages	301
Studies		0
Training	Allocated as Salaries and Wages	75
Total Accounting Expenses		2,722
ADMINISTRATION EXPENSES (1,000s)		
Admin Supervision	Allocated as Salaries and Wages	1,830
Tourism Promotion Expenses	Allocated as Salaries and Wages	275
Insurance - Generation Related	PS-DMND (A)	4,352
Insurance - T&D Related	Allocated as T&D Gross Plant	7,397
Insurance - General Property	Allocated as Salaries and Wages	718
Regulatory Fees	Allocated as Salaries and Wages	1,363
Training	Allocated as Salaries and Wages	53
Corporate Services	Allocated as Salaries and Wages	13
Hurricane Assistance	Allocated as Salaries and Wages	59
Purchasing expenses	Allocated as Gross Plant less Land and Right of Way	1,101
Stores expenses	Allocated as Materials and Supplies	1,518
Total Administration Expenses		18,679

Schedule 9 (continued)

O&M Expense Detail

MARKETNG & COMMUNICATIONS EXPENSES (1,000s)		
Marketing & Comm. Supervision	Allocated as Salaries and Wages	556
Communications Supervision	Allocated as Salaries and Wages	276
Marketing		0
Key Accounts		
To LP	DA	261
To SVP F	DA	30
To SVP E	DA	82
Demand Side Management		
To LP	DA	2
To SVP F	DA	0
To SVP E	DA	1
Training	Allocated as Salaries and Wages	57
Information Centre	Allocated as Salaries and Wages	132
Studies		
To Dom	DA	21
To LP	DA	13
To SVP F	DA	2
To SVP1 E	DA	6
Cust Comm. & Public Relations	Allocated as Salaries and Wages	675
Total Marketing & Communications		2,113
HUMAN RESOURCES EXPENSES (1,000s)		
Human Resources Supervision	Allocated as Salaries and Wages	1,106
Admin Office Expenses	Allocated as Salaries and Wages	838
Admin Building Maintenance	Allocated as Salaries and Wages	1,554
Legal Fees		0
Advertising	Allocated as Salaries and Wages	92
Employee Welfare	Allocated as Salaries and Wages	2,767
Training	Allocated as Salaries and Wages	756
Payroll	Allocated as Salaries and Wages	358
Health Safety Environment Quality	Allocated as Salaries and Wages	316
Quality Improvement	Allocated as Salaries and Wages	23
Security		0
Studies	Allocated as Salaries and Wages	200
Total Human Resources Expenses		8,009
O&M Excluding Fuel		103,140
Fuel		297,612
Total		400,752

Schedule 10

Depreciation Expenses and Other Taxes Detail

DEPRECIATION EXPENSE	Allocation	$Total
POWER SUPPLY	PS-DMND (A)	15,311
TRANSMISSION & DISTRIBUTION		
SUBSTATIONS	Allocation based on data provided by BLPC	2,754
POLES & ACCESSORIES	Allocation based on data provided by BLPC	4,068
OVERHEAD CONDUCTORS	Allocation based on data provided by BLPC	1,446
UNDERGROUND CABLES	Allocation based on data provided by BLPC	3,451
TRANSFORMERS	D-TRANS (E)	2,238
SERVICES	SERV	1,410
STREET LIGHTING	SL (G)	603
METERS & METER FACILITIES	METERS	568
TOTAL T&D		16,539
GENERAL PROPERTY	*Allocated as Salaries and Wages*	5,410
LAND & RIGHTS OF WAY	Allocated as Gross Plant less Land and Right of Way	-
TOTAL DEPRECIATION EXPENSE		37,261
LAND TAXES	Allocated as Gross Plant less Land and Right of Way	2,567
LICENSE FEE	Allocated as Salaries and Wages	750
TOTAL TAXES OTHER		3,317
INCOME TAX ITEMS		
TIMING DIFFERENCES(ASSETS)		3,204
TIMING DIFFERENCES(PROV.)		(4,409)
Deferred Income Tax Credit		(1,205)

Schedule 11
Electric Plant in Service

	Allocation	Average $ Balance
POWER SUPPLY	PS-DMND (A)	462,653
TRANSMISSION & DISTRIBUTION		
SUBSTATIONS	Allocation based on data provided by BLPC	85,581
POLES & ACCESSORIES	Allocation based on data provided by BLPC	71,370
OVERHEAD CONDUCTORS	Allocation based on data provided by BLPC	36,802
UNDERGROUND CABLES	Allocation based on data provided by BLPC	112,045
TRANSFORMERS	D-TRANS (E)	45,482
SERVICES	SERV	26,968
STREET LIGHTING	SL (G)	10,513
METERS & METER FACILITIES	METERS	11,505
TOTAL T&D		400,266
GENERAL PROPERTY	Allocated as Salaries and Wages	74,729
LAND & RIGHTS OF WAY	Allocated as Gross Plant less Land and Right of Way	0
TOTAL ELECTRIC PLANT		937,647

Schedule 12
Other Plant in Service

	Allocation	Average Balance
CWIP		
POWER SUPPLY	PS-DMND (A)	156
T&D	*Allocated on information from BLPC*	*3,318*
GENERAL	Allocated as Salaries and Wages	718
Total CWIP		4,193
CASH WORKING CAPITAL	Allocated as O&M less Fuel	12,893
CUSTOMER CONTRIBUTIONS	*Allocated on information from BLPC*	*(1,635)*
MATERIALS & SUPPLIES		
POWER SUPPLY	PS-DMND (A)	14,739
FUEL & LUBRUICATING OILS	PS-DMND (A)	10,562
T&D	Allocated as T&D Gross Plant	11,889
TOTAL M&S		37,190
DEFERRED CHARGES & CREDITS		
ACCUM. DEFERRED TAXES	Allocated as Gross Plant less Land and Right of Way	(19,083)
ACCUM. ITC	Allocated as Gross Plant less Land and Right of Way	-
FINANCING CHARGES	Allocated as Gross Plant less Land and Right of Way	-
ACCUM. MANUFACTURES TAXES CREDIT	Allocated as Gross Plant less Land and Right of Way	-
TOTAL DEFERRED CHARGES & CREDITS		(19,083)

Schedule 13
Accumulated Depreciation

	Allocation	Average $ Balance
POWER SUPPLY	PS-DMND (A)	239,031
TRANSMISSION & DISTRIBUTION		
SUBSTATIONS	Allocation based on data provided by BLPC	36,620
POLES & ACCESSORIES	Allocation based on data provided by BLPC	38,132
OVERHEAD CONDUCTORS	Allocation based on data provided by BLPC	17,153
UNDERGROUND CABLES	Allocation based on data provided by BLPC	16,299
TRANSFORMERS	D-TRANS (E)	18,121
SERVICES	SERV	11,855
STREET LIGHTING	SL (G)	6,702
METERS & METER FACILITIES	METERS	5,772
TOTAL T&D		150,654
GENERAL PROPERTY	Allocated as Salaries and Wages	37,323
LAND & RIGHTS OF WAY	Allocated as Gross Plant less Land and Right of Way	-
TOTAL ELECTRIC PLANT		427,007

Schedule 14

Unit Costs

	Units	System Unitized Cost	Units	Dom Unitized Cost	Units	GS Total Unitized Cost	Units	SVP Total Unitized Cost	Units	LP Unitized Cost	Units	SL Unitized Cost
Power Supply Demand	$/kVA	$ *38.7732*	$/kWh	$ *0.0657*	$/kWh	$ *0.1218*	$/kVA	$ *28.5019*	$/kVA	$ *28.8241*	$/kWh	$ -
Power Supply Energy	$/kWh	$ 0.0137	$/kWh	$ 0.0138	$/kWh	$ 0.0133	$/kWh	$ 0.0139	$/kWh	$ 0.0136	$/kWh	$ 0.0139
Transmission Demand	$/kVA	$ 7.5848	$/kWh	$ 0.0113	$/kWh	$ 0.0227	$/kVA	$ 5.6039	$/kVA	$ 6.1532	$/kWh	$ -
Distribution Substations	$/kVA	$ 3.1105	$/kWh	$ 0.0080	$/kWh	$ 0.0090	$/kVA	$ 1.9052	$/kVA	$ 2.0390	$/kWh	$ 0.0085
Distribution Lines	$/kVA	$ 8.5547	$/kWh	$ 0.0221	$/kWh	$ 0.0248	$/kVA	$ 5.2442	$/kVA	$ 5.6253	$/kWh	$ 0.0231
Line Transformers	$/kVA	$ 4.0120	$/kWh	$ 0.0137	$/kWh	$ 0.0153	$/kVA	$ 3.2159	$/kVA	$ -	$/kWh	$ 0.0148
Distribution Lines -2ndry	$/kVA	$ 4.2639	$/kWh	$ 0.0242	$/kWh	$ 0.0170	$/kVA	$ 1.5381	$/kVA	$ -	$/cust	$ 0.8562
Street Lighting	$/kVA	$ 0.6402	$/kWh	$ -	$/kWh	$ -	$/kVA	$ -	$/kVA	$ -	$/cust	$ 4.9003
Distribution - Other	$/kVA	$ -	$/kWh	$ -	$/kWh	$ -	$/kVA	$ -	$/kVA	$ -	$/kWh	$ -
Services	$/cust	$ 1.8717	$/cust	$ 2.5048	$/cust	$ 1.8212	$/cust	$ -	$/cust	$ -	$/kWh	$ -
Meters	$/cust	$ 1.3515	$/cust	$ 0.9204	$/cust	$ 1.5238	$/cust	$ 6.9146	$/cust	$ 292.2067	$/kWh	$ -
Meter Reading	$/cust	$ 0.8047	$/cust	$ 0.9797	$/cust	$ 1.0190	$/cust	$ 1.2817	$/cust	$ 1.2891	$/kWh	$ -
Billing & Accounting	$/cust	$ -	$/cust	$ -	$/cust	$ -	$/cust	$ -	$/cust	$ -	$/kWh	$ -
Customer Accounts	$/cust	$ -	$/cust	$ -	$/cust	$ -	$/cust	$ -	$/cust	$ -	$/kWh	$ -
Uncollectible	$/cust	$ 0.3226	$/cust	$ 0.2174	$/cust	$ 0.4901	$/cust	$ 4.0220	$/cust	$ -	$/kWh	$ -
Revenue Related	$/kVA	$ -	$/kWh	$ -	$/kWh	$ -	$/kVA	$ -	$/kVA	$ -	$/kWh	$ -
For Direct Assignment	$/kVA	$ 0.2025	$/kWh	$ 0.0004	$/kWh	$ 0.0002	$/kVA	$ 0.0758	$/kVA	$ 0.2985	$/kWh	$ -
Customer Service 1	$/cust	$ 4.3926	$/cust	$ 5.4135	$/cust	$ 5.6304	$/cust	$ 5.4429	$/cust	$ 5.4738	$/kWh	$ -
Customer Service 2	$/cust	$ 0.3691	$/cust	$ 0.3836	$/cust	$ 0.5985	$/cust	$ 1.5428	$/cust	$ 1.5516	$/kWh	$ -
Fuel Costs	$/kWh	$ 0.3153	$/kWh	$ 0.3153	$/kWh	$ 0.3153	$/kWh	$ 0.3153	$/kWh	$ 0.3153	$/kWh	$ 0.3153
Income Tax	$/kVA	$ (0.1383)	$/kWh	$ (0.0036)	$/kWh	$ (0.0031)	$/kVA	$ (0.0790)	$/kVA	$ 1.2577	$/kWh	$(0.0144)
Total Per kWh		$ 0.3290		$ 0.4708		$ 0.5362		$ 0.3291		$ 0.3288		$ 0.3611
Total Per kVA		$ 67.0036		$ -		$ -		$ 46.0060		$ 44.1977		$ -
Total per Customer		$ 9.1122		$ 10.4194		$ 11.0830		$ 19.2041		$ 300.5212		$ 5.7565
Fuel Clause		$ *0.2889*		$ *0.2889*		$ 0.2889		$ 0.2889		$ 0.2889		$ 0.2889
Basic Rate (with 2.64 c)		$ 0.0401		$ 0.1819		$ 0.2474		$ 0.0403		$ 0.0400		$ 0.0722
Basic Rate (without 2.64 c)		$ 0.0137		$ 0.1555		$ 0.2210		$ 0.0139		$ 0.0136		$ 0.0458

Schedule 15

FUEL REVENUE TIMING ADJUSTMENT FOR COST OF SERVICE (COS)

Fuel Adjustment Clause revenues in COS	=	$272,291,548
Emb. fuel revenue in base rates (2.64)	=	$24,922,543
Fuel expenses in COS	=	($297,612,203)
Fuel revenue timing adjustment for COS	=	$398,112

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