STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
PUBLIC UTILITIES COMMISSION

IN RE: BLOCK ISLAND POWER COMPANY	:	
GENERAL RATE FILING	:	**DOCKET NO. 3655**

REPORT AND ORDER

I. Introduction

On December 17, 2004, Block Island Power Company ("BIPCo or Company") filed with the Public Utilities Commission ("Commission") an application for a General Rate Change, seeking an increase in revenues of $463,171 or 21.96%. BIPCo also filed an alternative rate design option which would have resulted in an across the board rate increase of 11.49%. BIPCo further requested authority to apply a five year surcharge designed to collect $50,000 annual for Integrated Resource Planning ("IRP") and Demand Side Management activities ("DSM"). The Test Year used in this case was FYE May 31, 2004 while the Rate Year is Fiscal Year Ending May 31, 2006. The proposed effective date of the tariff change was January 16, 2005 and on January 14, 2005, the Commission suspended the effective date pending its investigation.[1]

II. Town's Motion for Determination of Scope of Proceeding

On or about January 6, 2005, the Town of New Shoreham ("Town") filed a Motion for Determination of Scope of Proceeding. On January 17, 2005, BIPCo filed a Response to the Motion, indicating that it had already raised in its direct filing each of the issues addressed by the Town. At its open meeting of February 17, 2005, the Commission declined to specifically define each of the issues to be addressed in the

[1] By Order No. 18157 (issued February 18, 2005), following an Open Meeting decision, the Commission denied a Motion to Invervene made by the Block Island Sustainability Coalition. The Town of New Shoreham's Motion to Intervene was granted pursuant to Commission Rule of Practice and Procedure 1.13(e).

BIPCo rate case because such a determination in a General Rate Case could result in too much of a constraint on the Commission's ability to set just and reasonable rates.

The Commission noted that the real issue was the Town's request for the rate case to include discussion of an IRP and potential DSM program. BIPCo raised both of these issues in its direct filing and Commission staff had already issued data requests regarding these issues. The Commission noted that these issues are appropriate for consideration in the rate case.

The Commission cautioned that if, at the end of the statutory deadline for determination of this case, one or both of these issues were to delay the Commission's ability to decide the case, the Commission could bifurcate the docket in order to decide the distribution rates and further consider the IRP and DSM issues.

III. Motion for Interim Relief

On January 18, 2005, BIPCo filed a Motion for Interim Relief, seeking to implement a change to its rate structure prior to the conclusion of its pending rate proceeding. BIPCo's summer rates are in effect June 1 through September 30 each year. BIPCo was seeking to implement the summer rates commencing on May 1, 2005. According to the Motion for Interim Relief, BIPCo alleged that it was "facing extraordinary, immediate and irreparable injury that can be avoided by the granting of the interim relief requested herein."

BIPCo asserted that the requested relief would allow the Company to generate an additional $111,000. According to BIPCo, it needed the interim relief because without it, the Company could be in default of its Rural Utilities Service ("RUS") first mortgage financing. According to BIPCo, the recent unforeseen event that caused this was

BIPCo's decision to file for a lower total rate increase with an extended summer rate period rather than to file for a higher rate increase with the existing summer rate period. Specifically, "the reasonable recent unforeseen event was the fact that the Commission could choose the rate design change rather than the across-the-board increase option [that BIPCo filed]." BIPCo also cited cash flow problems which existed during FY 2004, which ended May 31, 2004.

The Town and the Division of Public Utilities and Carriers ("Division") objected on the basis that BIPCo had not met the requirements to justify interim relief. Both parties requested summary disposition of the matter. First, they argued that there is no "emergency" as previously defined by the Commission regardless of whether the Motion alleges an emergency. Second, they argued that there was no immediate and irreparable injury.

BIPCo objected to the Motion for Summary Disposition, arguing that there was a material issue of fact regarding whether or not BIPCo had made its case regarding the need for interim relief. BIPCo listed nine issues of fact that it believed constituted facts material to the decision.

The standard for interim relief is a determination that the BIPCo has alleged such extraordinary facts of immediate and irreparable injury as would justify the Commission's exercise of discretion by granting interim relief prior to a final decision. The standard for summary disposition is a determination by the Commission that there is no genuine issue of fact material to the decision. In order to decide whether Summary Disposition on the interim relief is appropriate, the Commission must determine the following: (1) whether BIPCo alleged any extraordinary facts such as something out of the ordinary has happened in the business, (2) whether BIPCo has alleged any extraordinary facts that leads the Commission to believe that the Company is facing immediate and irreparable injury such as ceasing or imminently cease operations without the relief sought. The Commission determined that neither criterion was satisfied and found that there were no material facts in dispute. Also, the Commission ruled that BIPCo had not met the standards for interim relief under its decision in the matter of Pawtucket Water Supply Board, Docket No. 3164 (Order No. 16398 issued October 10, 2000), wherein the Commission stated, that a public utility must show "that, without interim rate relief, the [utility] system has been or will to a reasonable degree of certainty be jeopardized in its functioning."

IV. Pre-Filed Testimony

In support of its filing, BIPCo submitted direct testimony of Walter Edge and David Bebyn, its consultants along with the testimony of Jerome Edwards, BIPCo's President, Michael Wagner, BIPCo's Vice President, Clifford McGinnes, BIPCo's Chief Operating Officer, and Albert Casazza, BIPCo's Treasurer.

On April 4, 2005, the Town submitted the pre-filed testimony of its consultant, Stan Faryniarz, an economist and load forecasting specialist. Mr. Faryniarz's testimony focused on DSM, IRP and rate design.[2]

On April 7, 2005, the Division filed direct testimony of its consultants, Thomas Catlin of Exeter Associates, Inc. to address the Company's revenue requirements and Bruce Oliver of Revilo Hill Associates, Inc. to address the Company's rate design. Mr.

[2] Town Exhibit 1 (Pre-Filed Testimony of Stan Faryniarz).

Catlin calculated BIPCo's overall non-fuel revenue requirement at $2,303,404, representing an increase over revenues at present rates of $194,147.[3]

In his testimony, Mr. Edge explained reasons for BIPCo's increased revenue requirement, noting that the Company's last rate increase went into effect approximately thirteen years prior to the instant filing. He addressed revenues and pointed to normal inflationary increases in operations and payroll expenses including increases in management fees and commencement of repayment on Rural Utilities Services ("RUS") loans. Among other expenses, Mr. Edge discussed pension costs, management fees, regulatory and rate case expenses, engine maintenance and lineman contracting.[4] Mr. Catlin made adjustments to wage increases, the management fees, health insurance premiums, engine maintenance, insurance premiums and federal income tax calculations. He made no adjustment to claimed Selective Catalytic Reduction ("SCR") maintenance costs, but recommended the establishment of a reserve account to track actual catalyst replacement costs.[5]

Addressing rate base, Mr. Edge calculated total rate base at $4,604,693.[6] In conjunction with this calculation, he discussed capital additions, including, among other smaller purchases, a FY 2005 purchase of a new CAT engine, three electric exhaust fans, wrapping of three engines, and six voltage regulators.[7] Mr. Catlin made several adjustments to rate base, including decreasing Net Utility Plant, Working Capital, and

[3] Division Exhibit 1 (Pre-Filed Testimony of Thomas Catlin), p. 4.
[4] BIPCo Exhibit 2 (Pre-Filed Testimony of Walter Edge), pp. 3-26.
[5] Division Exhibit 1, pp. 11-19, TSC-10, TSC-11, TSC-12, TSC-13, TSC-14.
[6] BIPCo Exhibit 2 at WEE-16.
[7] Id. at 28.

Accumulated Deferred Income Taxes. These adjustments resulted in total rate base of $4,239,190.[8]

Turning to BIPCo's capital structure and rate of return, Mr. Edge calculated the weighted cost of debt and equity at 6.57%, which applied to a rate base of $4,604,693, results in a return on rate base of $302,438.[9] He argued that the Company should continue to be allowed the opportunity to earn a return on equity ("ROE") of 11.7%. Mr. Edge pointed to the risk of BIPCo compared to Narragansett Electric Company, which is allowed a lower ROE.[10] Mr. Catlin, however, proposed a reduction of BIPCo's ROE to 10.5%. He calculated the weighted cost of debt and equity at 6.36%, which applied to a rate base of 4,239,190, results in a return on rate base, of $269,522.[11]

Discussing BIPCo's rate design proposal, Mr. Edge explained that a limited review of commercial customers revealed usage patterns in May and October which reflected summer usage more than winter usage. Therefore, the Company was proposing to extend the summer rate period to cover those two months. Doing so, he explained, would reduce the requested revenue increase to 11.49%. The reason is that the Company would collect approximately $200,000 more in revenues during those two months alone. However, he explained that if this rate design option were chosen, in order to meet RUS requirements, the change would need to be made prior to the end of the rate case investigation. In addition to being able to meet RUS deadlines, Mr. Edge opined that such relief would assist BIPCo in addressing cash flow concerns.[12]

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[8] Division Exhibit 1, pp. 6-11, TSC-2. For his adjustment to Cash Working Capital, Mr. Catlin relied on the testimony of his colleague, Lafayette K. Morgan, submitted as Division Exhibit 2.
[9] BIPCo Exhibit 2, at WEE-15, WEE-16, WEE-17.
[10] Id. at 31-32.
[11] Division Exhibit 1, pp. 5-6, TSC-1, TSC-2, TSC-3.
[12] BIPCo Exhibit 2, pp. 33-36. In his testimony, Mr. Bebyn explained that he had prepared a lead-lag study, resulting in a proposed requirement of $190,197 in working capital in order to address normal cash-

Contrary to Mr. Edge's assertions, Mr. Oliver's testimony on behalf of the Division stated that his class cost of service analyses did not show a strong correspondence between costs of service and revenue at present rates for the test year.[13] He maintained that the revenue for Demand-Metered General Service appears to fall well below its allocated costs for the test year. His studies showed that the Street Lighting Service was not adequately priced.[14] He recommended the Commission require any approved rate increase be distributed among rate classes in a manner that shifts rate for all classes of customers in the direction of their respective cost of service.[15]

Mr. Oliver testified that he could find no clear demarcation between summer and winter months usage, and thus, did "not find a compelling case for altering BIPCo's current seasonal rate definitions at this time."[16] On behalf of the Town, Mr. Faryniarz agreed that the Commission should deny the request to increase the summer period by two months, stating that "[c]harging a higher block rate for two additional months does not send the correct price signal, because those are not months in which marginal costs (particularly of capacity) are the highest."[17] He suggested other methods of sending appropriate cost signals to summer customers such as increasing summer block rates and instituting a system charge on non-demand metered customers.[18]

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flow issues. BIPCo Exhibit 3 (Pre-Filed Testimony of David Bebyn), pp. 4-6. Additionally, Mr. Bebyn further discussed the rate design and provided schedules reflecting the rate design proposals contained in Mr. Edge's testimony. Id. at 7-9, DGB-7.

[13] Division Exhibit 3 (Pre-Filed Testimony of Bruce Oliver), 2-3, 6-7.
[14] Id. at 3, 14-16.
[15] Id. at 4.
[16] Id. at 3, 8-13.
[17] Town Exhibit 1, p. 25.
[18] Id. at 26-27.

Mr. Faryniarz's testimony also focused on the need for an IRP and DSM program and proposals of what the Company should consider.[19] He suggested the surcharge be focused more on summer rates to appropriately address the fact that much of the load growth on the system and related planning requirements results from summertime consumption.[20] In response to Town concerns, BIPCo suggested a surcharge designed to provide $50,000 in revenues be allowed for five years to cover DSM and IRP activities.[21] Mr. Oliver declared that the Company needs to perform further evaluations on generation supply alternatives, noting that it may be advisable for BIPCo, the Town and other stakeholders to work cooperatively to identify more cost-effective generation supply or DSM alternatives.[22] However, he cautioned that, "[d]espite the Company's comparatively high costs of oil-fired generation, BIPCo's expenditure of large amounts of time and resources to develop and implant a well-developed integrated resources plan may not be cost-effective for ratepayers."[23] He recommended the Commission encourage the formation of a working group to tackle these issues.[24] He supported the concept of a surcharge, but recommended that: (1) it be deposited into a restricted account, (2) the funds be used as cost-effectively as possible, (3) the period over which benefits accrue should correspond to the recovery period, (4) the rate be applied in a manner that appropriately distributes responsibility for the costs among year-round customers and summer customers, and (5) the costs to be recovered be more specifically outlined.[25]

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[19] Town Exhibit 1, pp. 3-23, 28-39.
[20] Id. at 31.
[21] BIPCo Exhibit 2, p. 37.
[22] Division Exhibit 3, pp. 3, 16-23.
[23] Id. at 4
[24] Id. at 5.
[25] Id. at 17-18.

Mr. Edwards, Mr. Wagner, Mr. McGinnes, and Mr. Casazza each provided testimony explaining their respective role with the Company and the need for a rate increase.[26]

V. Rebuttal Testimony

On April 21, 2005, BIPCo submitted the Rebuttal Testimony of Walter Edge. Mr. Edge stated that BIPCo has accepted the rate design recommendations of the Division. He also indicated that the Division and BIPCo had entered into a proposed settlement regarding rate base, rate of return, revenue requirement and rate design. According to Mr. Edge, BIPCo believed Mr. Oliver's positions on IRP and DSM were reasonable.[27] Responding to the Town's testimony regarding IRP and DSM, Mr. Edge set forth point by point why BIPCo disagreed with the recommendations stated in Mr. Faryniarz's testimony. Mr. Edge's main points of disagreement generally focused on cost and timing of the proposals.[28]

VI. Settlement

On May 9, 2005, the parties filed a Stipulation and Settlement ("Settlement") resolving all revenue requirement, rate base, rate or return, long range planning, and rate design issues in this docket.[29] BIPCO's base revenue requirement was settled at $2,328,304 representing an increase of $219,047 or 10.4% over the test year. Rate of return on equity was settled at 10.5%. Rate base was settled at $4,240,303 and the rate of return on rate base is settled at 6.36% or $269,593. The new rates would be effective for consumption on and after June 1, 2005.

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[26] BIPCo. Exhibits 4 (Pre-Filed Testimony of Jerome Edwards), 5 (Pre-Filed Testimony of Michael Wagner), 6 (Pre-Filed Testimony of Clifford McGinnis), and 9 (Pre-Filed Testimony of Albert Cassaza).
[27] BIPCo Exhibit 7 (Rebuttal Testimony of Walter Edge), p. 1.
[28] Id. at 2-5.
[29] A copy of the Settlement is attached hereto and marked as Appendix A.

BIPCO will establish a restricted account that will be funded in the amount of $210,272 annually. These funds will be utilized for the SCR system, engine maintenance, engine installation and related work. The rate increase will be applied according to the rate design of Division witness Bruce Oliver.

The summer billing period will remain the period June through September. During the summer billing period, customers will be charged $0.01 per kWh as part of the fuel surcharge for a period of three years from the effective date of the increase. Funds accumulated from this surcharge, expected to be approximately $55,000 per year, are to be used for IRP/DSM endeavors. These funds are additional amounts that will be collected from ratepayers over and above the $219,047 increase in base rates. The parties agreed to participate in a working group to oversee the development of an IRP to be implemented by BIPCo, subject to oversight by the Commission. Additionally, BIPCO agrees to justify its compensation practices for owners and management in its next base rate filing.

VII. Hearing

Following notice, a public hearing was held at the Commission's offices, 89 Jefferson Boulevard, Warwick, Rhode Island, on May 12, 2005 to assess the propriety of the Settlement.[30] The following appearances were entered:

FOR BLOCK ISLAND POWER CO.:	Michael McElroy, Esq.
FOR TOWN OF NEW SHOREHAM:	Alan Mandl, Esq.
FOR DIVISION:	William Lueker, Esq. Special Assistant Attorney General

[30] A previous hearing was held in the Town of New Shoreham on April 28, 2005 at 10:30 a.m. for the purposes of taking public comment.

FOR COMMISSION: Cynthia G. Wilson, Esq.
Senior Legal Counsel

The parties presented their witnesses as a panel: Walter Edge on behalf of BIPCo, and Bruce Oliver and Thomas Catlin on behalf of the Division. Each of the witnesses testified that they believed the Commission should approve the Settlement. Mr. Oliver testified that the average year-round residential customer using 500 kWh per month would experience an approximately $9.50 increase per month which includes the one cent kWh surcharge for DSM/IRP programs.

Addressing the fuel adjustment clause, Mr. Edge agreed that prior to approval of the Settlement all costs contained in the charge are related to fuel costs. He explained that the rationale for including the DSM/IRP surcharge in the fuel adjustment clause as opposed to itemizing on the bill is for ease of bill formatting.[31] Mr. Oliver suggested that because the purpose of the surcharge is to reduce fuel consumption and its costs, it is appropriately included in the fuel adjustment clause. Mr. Edge assured the Commission that the revenues from the surcharge would be tracked separately from the other fuel adjustment revenues and deposited into a restricted account.[32] Mr. Edge agreed to submit a courtesy copy of BIPCo's monthly fuel adjustment reconciliation to the Commission at the same time as the Company files with the Division.[33]

Discussing the formation of a DSM/IRP working group, Mr. Edge and Mr. Oliver explained that there is no set number of participants of the working group but that each of the parties will have one vote, absent a consensus, regardless of the number of participants they have. On behalf of the Town, Mr. Mandl spoke in agreement with the

[31] Mr. Wagner indicated that the Company could advise customers of the DSM/IRP charge either through a bill message or bill insert. Tr. 5/12/05, p. 132.
[32] Tr. 5/12/05, pp. 25-27.
[33] Id. at 28.

representation. Mr. Scialabba, Chief Accountant to the Division was sworn in to provide further information regarding the composition and dynamics of the working group, specifically with regard to seeking input from non-parties to the Settlement.[34] He testified that rather than creating an overly formal group, the working group could, with the Town and Company involvement, advise the islanders that this group existed and could invite those who could be identified to provide input. He stated that the specific manner of that has not been identified by the group.[35] He believed this would be one of the first things determined by the group when it begins meeting.[36] He clarified that although input will be sought from non-parties, it will be the parties which will ultimately make decisions for Commission review.[37] He agreed that any consultant hired by the working group will be working for the whole group and not any one party.[38] The parties agreed that, while the working group will be filing a report with the Commission for review and possibly approval, post-report action and any legal ramifications of the working group's recommendations have yet to be determined.[39] Responding to a Commission concern that the parties had agreed to a dispute resolution process that, if utilized, could lead to appeals, regardless of the subject of dispute, the parties agreed that the dispute resolution provision would only be as a last resort, given the fact that the purpose of the group was to negotiate.[40]

Mr. Wagner, BIPCo's general manager, was sworn in to testify regarding the long-range planning and distribution studies that were performed. The witnesses

[34] Id. at 33.
[35] Id. at 34.
[36] Id.
[37] Id. at 35.
[38] Id.
[39] Id. at 36-38.
[40] Id. at 45.

discussed Commission concerns that studies paid for with ratepayer funds not be disregarded by the working group.[41] The parties represented that there is value to the studies which will be considered by the working group.[42]

Discussing vacant positions, specifically BIPCo's use of an independent company to fill the lineman's role, Mr. Wagner stated that the position has not been advertised because of his belief that there is a shortage of a qualified labor pool. Additionally, he indicated that use of an outside company has provided opportunities for the company to learn new techniques. Finally, Mr. Wagner expressed concern regarding the impact the location of the system may have on the availability of prospective candidates.[43] With regard to his own position, Mr. Wagner had agreed to stay with the Company until the fall 2005. However, as of the date of the hearing, the Company had not officially advertised his position.[44]

Addressing his retirement, Mr. Wagner indicated that the Company's proposal is to provide him with a pension of $1,000 per month. He was also involved in the profit sharing program and will receive benefits from that. Mr. Wagner conceded that he does not qualify for a pension under the Company's policy. Responding to a Commission concern that departure from company policy would set a precedent for the future, Mr. Edge testified that Mr. Wagner "just misses," with 36 years of service and his age. Mr. Edge also noted that the pension would only be provided until Mr. Wagner is 65 years old and then he would be able to draw on his social security. Finally, Mr. Edge indicated that because of the unique situation, this exception should not be seen as an indication

[41] Id. at 47-63.
[42] Id. at 61-63.
[43] Id. at 73-78; 118-120.
[44] Id. at 78, 85.

that all retired employees will receive the benefit in the future. Mr. Wagner added that there is one employee reaching retirement age, who will be eligible for a pension, in the next three to four years, but then nobody will reach retirement age for at least ten years.[45]

Regarding the management fee, Mr. Edge indicated that, rather than making payments to the managers through a third party entity, checks are made directly to individuals. According to Mr. Edge, the management recipients receive 1099s at the end of the year rather than W-2s.[46] He testified that the total management fee in FY 2005 was $192,000 and that the Company lost $118,000 in that same year.[47] Mr. Catlin explained that in the next rate case, the parties would look at whether or not the independent contractor approach or employee compensation approach is more appropriate for management. Mr. Edge then noted that he will be researching the issue for compliance with Internal Revenue Service regulations. He conceded that there are no formal job descriptions for the managers and a lack of formal enforcement of the usage policies for company-owned vehicles. It appeared from the testimony that the amount of compensation would be at issue in the next rate case as well.[48]

Addressing collections and write-offs, Mr. Edge explained that within the most recent eighteen months, BIPCo wrote off approximately $35,000 to $40,000 which represented several years of write-offs. He explained that there is not a regular policy regarding annual write-offs for nonpayment. He noted that customers may pre-pay their bills and that the Company works with other customers in order to accommodate cash

[45] Id. at 79-82. With regard to Merrill Slate, a retired employee, the Commission expressed concern that the provision of free electricity to him was in violation of the anti-discrimination provision of state law. Id. at 108-111.
[46] Id. at 86-87.
[47] Id. at 112.
[48] Id. at 85-88;94-101. Mr. Edge agreed to provide the Commission with the names of each company to which the salary checks are mailed and the results of his review of BIPCo's compensation plan with IRS regulations. Id. at 102.

flow issues.[49] With regard to a four-week time-share held by BIPCo following a bankruptcy of one of its customers, Mr. Edge indicated that it will be sold this year. However, because it was never recorded on the books properly, the entire sale will be considered profit, as the cost basis will be $0.00. Mr. Edge believed the time-share may be sold for approximately $15,000. He asserted that the sale will benefit the ratepayers rather than the shareholders.[50]

Addressing the Company's capital structure, Mr. Catlin noted that he had accepted Mr. Edge's capital structure and cost of debt. He indicated that if he had made adjustments, they would not have been significant given the fact that the equity ratio was so low, something he had noted in his direct pre-filed testimony. Mr. Catlin testified that BIPCo should attempt to increase its equity ratio to at least 30%. He suggested the Company could retain earnings or consider some additional form of equity infusion. However, he would not make any firm recommendations. He also added that the Company should make timelier rate filings.[51]

Addressing rate design, Mr. Oliver testified that while his rate design moves the classes toward their cost based rates, it does not actually achieve that goal. Commercial customers are one example of a class that was significantly below the other classes and as a result, will see a larger percentage increase. Mr. Oliver noted that there remain unknowns in the calculations, particularly with regard to peak load contribution. He concluded, however, that his rate design, which was accepted by the other parties, moves all classes closer to their cost of service.[52]

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[49] Id. at 129-30.
[50] Id. at 120-23.
[51] Id. at 125-28.
[52] Id. at 140-42.

VIII. Commission Findings

At its open meeting on May 26, 2005, the Commission discussed the Settlement. The Commission is concerned with the treatment of management fees drawn by the owners because they act as employees and not in a consultant capacity. The Commission does not believe it is in the best interest of ratepayers to allow BIPCo to put off justification of the management fees until the next rate case and accordingly, the Commission modified Section 9 of the Settlement regarding the compensation to the owners of BIPCo by requiring BIPCo to report, within 90 days from issuance of this Order, its justification and legal basis for how the Company pays its owners and/or management. Also, BIPCo must provide written job descriptions for its senior management. The funding level for management fees that is agreed in the Settlement remains the settled amount subject to the Commission determining if the amount in the settlement is appropriate.

With regard to the electricity being provided free to a retired employee, the Commission finds free service should not be provided to a retired employee by the utility because such provision of electricity does not fit under the exception in R.I.G.L. § 39-2-5. The statute specifically refers to employees, with no mention of retired employees. The exceptions within the provision appear to be referring to a benefit resulting from a current, not former, involvement with a utility's operations. Mr. Edge testified that the retired employee currently has no duties with BIPCo's operations.

Because of the fact that during the hearing, there was testimony that Mr. Wagner's position had not been advertised formally, BIPCo is directed to keep the Commission informed on the status of a suitable replacement for its General Manager. It would be unfortunate for the Company and the new General Manager if Mr. Wagner's replacement is not working on the system prior to Mr. Wagner's departure. The loss of his institutional knowledge would most likely be detrimental to the efficient operation of the utility.

In response to concerns raised during the public comment hearing and in an effort to eliminate duplicative efforts, Commission Staff will meet with the parties in the IRP working group to determine if the group could identify and recommend some metrics to monitor outages, reliability and customer service.

BIPCo's capitalization ratio of 83% debt level and 17% equity puts BIPCo in a tenuous financial position. As an investor-owned utility, debt is not the only method of raising cash for improvements to the system. Investor-owned utilities, unlike municipally owned utilities, can issue more stock. The Commission encouraged BIPCo to develop a financial plan to increase its equity level, while still maintaining and upgrading its system.

The Commission orders BIPCo to identify and explain the one cent surcharge for IRP/DSM included in the FAC on the monthly bills during the period that is collected from June through September.

Finally, the Commission notes that there were several instances during testimony where witnesses for the Company either testified that there were no policies in place for various situations or that the policies have not been applied equally to all Company officials/employee, for example, with regard to vehicle usage and pensions. This is a concern to the Commission which should be addressed in the future.

The Commission approves the Stipulation and Settlement with the modification to Section 9 of the Settlement noting that neither BIPCo nor the other parties objected to the modification. In accepting the rate design proposal, the Commission notes that it is consistent with the Commission's prior findings "that the Commission's goal all along has been to match the cost of service to the user of the service… [and] that philosophically, the Commission should be moving toward bringing the rates close to the cost of service."[53]

Accordingly, it is hereby

(18364) ORDERED:

1. Block Island Power Company's General Rate Filing made on December 17, 2004 is hereby denied and dismissed.

2. The Stipulation and Settlement filed on May 9, 2005, is hereby approved with the exception to the modification the Commission made to Section 9.

3. The first clause of the first sentence of Section 9 of the Stipulation of Settlement filed on May 9, 2005, is hereby revised as follows: the language "In the next base rate filing," is stricken and replaced with: Within ninety (90) days following the issuance of the Commission's written Order in this docket,.

4. Block Island Power Company shall cease, as of the effective date of this Order, to provide free electricity to retired employee(s) using ratepayer funds.

5. Block Island Power Company's annual revenues shall be increased by $219,047 for a total rate year base revenue requirement of $2,328,304.

6. The compliance tariffs filed with the Stipulation and Settlement are hereby approved for usage on and after June 1, 2005.

[53] Docket No. 3546, In Re: Pascoag Utility District General Rate Filing, Order No. 17820 (issued May 5, 2004), p. 21.

7. Block Island Power Company's authorized return on equity is 10.5%.

8. Block Island Power Company shall identify and explain the $0.01 surcharge for IRP/DSM included in the FAC on the monthly bills during the period that is collected from June through September

9. Block Island Power Company shall restrict $210,272 for catalysts for the SCR system, SCR related work, engine maintenance, installations and related work.

10. Block Island Power Company shall comply with all other findings and instructions contained in this Report and Order.

EFFECTIVE AT WARWICK, RHODE ISLAND ON JUNE 1, 2005 PURSUANT TO AN OPEN MEETING DECISION ON MAY 26, 2005. WRITTEN ORDER ISSUED SEPTEMBER 13, 2005.

PUBLIC UTILITIES COMMISSION

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Elia Germani, Chairman

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*Robert B. Holbrook, Commissioner

* I concur with the decision, but would have disallowed the $1,000 per month pension from rates for Mr. Wagner because he does not qualify under the Company's policy and, because there were no contributions to his pension during his service at the Company, future ratepayers are paying for a service they are not receiving. Therefore, I do not believe this is an appropriate expense for BIPCo's ratepayers to bear.

STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS
BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE: BLOCK ISLAND POWER)
COMPANY GENERAL)
RATE FILING)

DOCKET No.: 3655

STIPULATION AND SETTLEMENT

Block Island Power Company ("BIPCO" or "Company"), the Division of Public Utilities and Carriers ("Division"), and the Town of New Shoreham ("Town"), hereby agree to this stipulation and settlement ("Agreement" or "Settlement Agreement") which constitutes a settlement of all revenue requirement, rate base, rate of return, long range planning, and rate design issues in this docket.

Recitals

On December 17, 2004, BIPCO filed with the Commission an application to increase its rates by $463,171, or approximately 21.96% above its currently authorized revenue level (excluding fuel related revenues) in the rate year at current rates of $2,109,257.

In response to BIPCO's filing the Division conducted an investigation of BIPCO's rate increase requests through extensive discovery methods by aid of its staff and outside consultants. Based upon its investigation and findings, the Division filed its direct case with the Commission and recommended that BIPCO's present revenues be increased by $194,147, resulting in a downward adjustment to BIPCO's revenue request by $269,024. The Division also recommended certain rate design changes in terms of allocating costs between the classes and revising BIPCO's Street Lighting

Service Rate S. The Division recommended retaining BIPCO's current seasonal rating period definitions (June through September). The result of the Division's rate design recommendation is that the increase will be distributed among rate classes in a manner that moves rates for all classes in the direction of their indicated cost of service.

The Town intervened in this matter, conducted discovery, submitted pre-filed expert testimony on long-range planning and rate design issues and answered discovery by BIPCO. BIPCO submitted rebuttal testimony in reply to the Town's expert testimony.

After due consideration of the testimony, exhibits, and other documents included in the filings by BIPCO, the Division, and the Town, the Parties now have agreed to a comprehensive settlement in the rate case which resolves all issues in this proceeding relating to BIPCO's revenue requirement, rate base, rate of return, long range planning and rate design.

This Settlement Agreement is as follows:

Section 1: BIPCO's additional revenue requirement for this Settlement is settled at $219,047, which results in total stipulated rate year revenue (excluding fuel revenues) of $2,328,304. The following supporting schedules are attached hereto and incorporated by reference herein: TSC-1 (summary of operating income, determination of revenue increase, and rate of return summary), TSC-2 (summary of rate base and adjustments to rate base), TSC-3 (summary of adjustments to net income), TSC-4 (income tax reconciliation), TSC-5 (adjustment to restate accumulated deferred income taxes), TSC-6 (adjustment to materials and supplies), TSC-7 (adjustment to reflect updated replacement plan for engine no. 25), TSC-8 (adjustment to reflect rate year depreciation expense), TSC-9 (adjustment to eliminate additional substation depreciation), TSC-10 (adjustment to labor and related costs), TSC-11 (adjustment to proposed management fee), TSC-12 (adjustment to medical and dental insurance expense), TSC-13 (adjustment to major engine maintenance expense), TSC-14 (adjustment to reflect actual general insurance premiums), LKM-1 (cash working capital summary), LKM-2 (calculation of operating expenses working capital), LKM-3 (calculation of operating expense payment lag), LKM-4 (calculation of average gross receipts tax lead days), LKM-5 (calculation of average interest lag), LKM-6 (calculation of average revenue lag days), BRO-5 rate design summary (page 1), residential rate R (page 2), commercial general rate G (page 3), commercial demand rate D (page 4), public rate P demand rate (page 5), public rate P non-demand rate (page 6), street light rate S (page 7), and revenue increase by type of charge (page 8).

Section 2: The following new tariffs are attached hereto and incorporated by reference herein: Residential Service Rate R (2 pages), General Service Rate G (2 pages), Demand-Metered General Service Rate D (1 page), Public Authority Service Rate P (2 pages), Street Lighting Service Rate S (1 page), Fuel Adjustment Clause Rider Rate FAC (3 pages), and Terms and Conditions (11 pages).

Section 3: The rate of return on equity is settled at 10.50%. BIPCO's rate base is settled at $4,240,303. The rate of return on rate base is settled at 6.36%. The overall return on rate base is settled at $269,593. The weighted average cost of debt is settled at 5.50%.

Section 4: Material rate base adjustments include agreed reductions from BIPCO's filing of (a) $116,797 for plant in service and (b) $76,444 for cash working capital.

Section 5: Material operating and maintenance adjustments include agreed reductions from BIPCO's filing of (a) $24,179 on the Company's claim for labor and labor related expenses, (b) $76,389 on the Company's claim for management fees, (c) $18,579 on the Company's claim for health insurance premiums, and (d) $80,000 on the Company's claim for engine maintenance. Other lesser adjustments were also made, as reflected in the attached schedules. These operating and maintenance (O&M) adjustments total $202,188, reducing the Company's O&M claimed net income from $1,800,851 to an agreed O&M net income of $1,598,663. (See schedule TSC-3, page 2 of 2).

Section 6: The parties agree that $210,272 shall be reserved for catalysts for the SCR system, for related SCR work, and for engine maintenance, installation and related work. That is, a reserve account shall be established in which $210,272 shall be accrued each year. Actual expenditures for engine and SCR maintenance, installation and related work will be charged to this reserve. Any difference between the $210,272 accrual included in rates and actual expenditures shall be addressed in a future proceeding. In addition, the reserve shall be credited by BIPCO with any net proceeds received by BIPCO through insurance payments, legal settlements or from vendors relating to catalysts for the SCR system, for related SCR work, and for engine maintenance, installation and related work. BIPCO shall inform the parties of the reserve balance and any charges and credits to the reserve on an annual basis (which information may be provided as part of its FERC Form 1 Annual Report).

Section 7: The rate increase will be applied as set forth in the attached schedules of Bruce R. Oliver and incorporated into the attached tariffs. The Parties agree that the current four month seasonal rate period shall be retained.

Section 8: The Parties agree that a surcharge of 1¢ per kilowatt hour shall be established for Demand Side Management (DSM) and Integrated Resource Planning (IRP) purposes as described in Town Attachment 1 to this Settlement (incorporated herein and made a part hereof) for a period of 3 years from the effective date of this increase. These funds shall be reserved solely for DSM and IRP purposes and accounted for separately by BIPCO. It is agreed that BIPCO shall have no obligation to perform any DSM or IRP programs for which funding is not available from this reserve. The fund shall be collected on kWh consumption in June, July, August, and September of each year through the fuel surcharge (FAC). BIPCO and the Town shall make their best efforts to investigate the availability of and to obtain additional resources, including but not limited to grants and the use of resources available through Rhode Island's governmental and educational institutions, to aid in carrying out the working group's efforts and related IRP and DSM planning and implementation as described in Town Attachment 1.

Section 9: In the next base rate filing, BIPCO will justify how it pays its owners and/or management (management fees, management salaries, dividends, director's fees, use of Company-owned or leased vehicles by owners and/or management, benefits provided to owners and/or management, etc., or some combination, and any other management-related transactions with affiliates) and show that its approach and the resulting payments are reasonable and in the best interest of ratepayers. Nothing in the foregoing language shall preclude the Town from filing a complaint with the Division or Commission on the issues set forth in Section 9.

Section 10: The parties agree that the new rates will go into effect for consumption on and after June 1, 2005.

Section 11: By entering into this settlement, matters or issues other than those explicitly identified in this agreement have not been settled upon or conceded by any party to this agreement, and nothing in this agreement shall preclude any party from taking any position in any future proceeding regarding such unsettled matters.

Section 12: This agreement is the result of a negotiated settlement. The discussions which have produced this Settlement have been conducted with the explicit understanding that all offers of settlement and discussions relating hereto are and shall be privileged, shall be without prejudice to the position of any party or participant presenting such offer or participating in any such discussion, and are not to be used in any manner in connection with these or other proceedings. The agreement by any party to the terms of this Agreement shall not be construed as an agreement as to any matter of fact or law beyond the terns hereof. In the event that the Commission rejects this Agreement, or modifies this Agreement or any provision therein, then this Agreement shall be deemed withdrawn and shall be null and void in all respects.

Section 13: This Agreement shall be binding upon all parties. If any party wishes to request Commission modification of Sections 8 or 9, the requesting party shall first obtain the consent of the other parties; provided, however, that such consent shall not be unreasonably withheld or delayed by any party.

Section 14: Within seven (7) days of a Commission order approving this Agreement in its entirety, BIPCO and the Town shall file a joint stipulation of dismissal of the Town's Complaint against BIPCO in Division Docket No. D-04-46, without prejudice.

Section 15: This Agreement has been reviewed and duly approved by the Town Council of the Town on May 6, 2005.

Section 16: This Stipulation and Settlement may be executed in counterparts.

The Parties hereby submit this Stipulation and Settlement to the Commission for approval.

IN WITNESS WHEREOF, this document has been executed by the appropriate representative of the parties identified below, each being fully authorized to do so. Dated this 6th day of May, 2005.

RESPECTFULLY SUBMITTED,

BLOCK ISLAND POWER COMPANY

By its attorney

____

Michael R. McElroy, Esq., Bar No. 2627
Schacht & McElroy
21 Dryden Lane
P.O. Box 6721
Providence, RI 02940-6721
Tel. (401) 351-4100
Fax (401) 421-5696

DIVISION OF PUBLIC UTILITIES AND CARRIERS

By its attorney

____

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Special Assistant Attorney General
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150 South Main Street
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Tel. (401) 274-4400, ext. 2299
Fax (401) 222-3016

TOWN OF NEW SHOREHAM

By its attorney,

____

Alan D. Mandl, Esq., Bar No 6590.
Mandl & Mandl LLP
10 Post Office Square – Suite 630
Boston, MA 02109
Tel. (617) 556-1998
Fax (617) 422-0946

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Settlement clean 5-4-05.doc

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Settlement clean 5-4-05.doc

TOWN ATTACHMENT 1

INTEGRATED RESOURCE PLANNING PROCESS
FOR BLOCK ISLAND POWER COMPANY
RHODE ISLAND PUBLIC UTILITIES COMMISSION DOCKET NO. 3655

Block Island Power Company (BIPCO), the Town of New Shoreham (Town), and the Division of Public Utilities and Carriers (Division) (together, the "parties") agree to cooperatively work together for the purpose of evaluating the manner in which the electricity needs of Block Island can best be met for current and future ratepayers of Block Island. The objective is to ensure that electric ratepayers on Block Island receive a safe, reliable, power supply in a cost-effective manner, while minimizing environmental and economic risks.

The parties agree to participate in a working group to oversee the development of an Integrated Resource Plan (IRP) to be implemented by BIPCO, subject to oversight by the Public Utilities Commission (PUC). The parties together will form a working group with a representative(s) from each of the signatories to the Settlement Agreement participating. The parties will have equal representation within the group. This working group will jointly engage a consultant(s) with sufficient expertise to evaluate the short and long-term electricity requirements of Block Island and propose a plan that best meets the objective of the parties. The parties will work cooperatively to seek input from all interested stakeholders.

The first meeting of the working group shall be within 90 days of the Commission's decision. The parties agree that the scope of the IRP analysis should include, but not necessarily be limited to:

a. 10-20 year forecast of the power demand and energy consumption for Block Island
b. an assessment of the condition and efficiency of existing generation and distribution systems and their capacity to meet forecasted demand
c. an assessment of whether conservation and other demand side measures would be a cost-effective way to reduce existing and forecasted peak demand.
d. an assessment of practical sources of generation, including alternatives to existing oil-fired generation, which will include, but not be limited to, practical methods for the development and financing of a cable to the mainland.
e. consideration of BIPCO plans to upgrade the existing distribution system in order to improve the reliability of service and reduce line losses

The working group will engage a consultant(s) to undertake the analysis and plan development, and such other persons deemed reasonably necessary and approved by the working group to assist in developing its findings. Funding for such a consultant(s) or other persons will come from the restricted account established under this Settlement (Section 8) and any other grants or other resources obtained for this purpose by BIPCO or the Town as provided for Under Section 8 of the Settlement, subject to the provisions provided for under Section 8 of the Settlement. Otherwise, each party to the working group will be responsible for any costs incurred by its appointees to the working group.

The parties will submit the results of the working group's efforts to the Commission for its review. The working group will submit joint reports on the progress of the group every six months, with the first report due six months after the issuance of the Commission's Order in this Docket. These reports will include detail on the group's expenditures. At the conclusion of the consultant's analysis and recommendation, the working group will strive to make a joint recommendation to the Commission. In the event that consensus is not achieved on joint recommendations from the working group, then each party shall retain the right to present its own comments and alternative recommendations to the Commission. Such alternative recommendations shall be filed with the Commission and provided to the other parties within thirty (30) days after the filing of the working group's report to the Commission. In the event that the working group submits a unanimous report, the parties shall request that the Commission adopt it and issue such other directives as it deems reasonable. In the event that any party submits alternative recommendations, the parties shall request that the Commission review all filings and issue such directives as to the conduct, implementation and funding of the IRP as it deems reasonable. Once the IRP is developed, BIPCO will implement such programs per Commission Order.

This Integrated Resource Planning Process and the working group shall remain in effect at least through BIPCO's development and implementation of IRP. The parties will make their best efforts to submit to the Commission the working group's report and recommendations for long range planning actions that are appropriate for BIPCO as soon as practicable, but agree that the submission will occur no later than two years after the date of the Commission's decision approving the Settlement in this Docket.

BIPCO, the Town, and the Division shall have the right to request that the Commission modify this Integrated Resource Planning Process described herein for good cause shown, after giving 14 days' prior written notice to the other parties. The working group will make a good faith effort to resolve any dispute among its members. Any disputes that cannot be resolved within the working group within 30 days may be brought by any working group member to the Commission for resolution. The parties agree that the Commission shall have jurisdiction over such a dispute and shall not contest the Commission's jurisdiction.

BLOCK ISLAND POWER COMPANY

Summary of Operating Income
Rate Year Ending May 31, 2006

	Amounts Per Company at Present Rates (1)	Division Adjustments	Amounts Per Division at Present Rates	Pro Forma Increase	Amounts at Proposed Rates
Operating Revenue					
Electricity Sales Revenue	$ 1,697,000		$ 1,697,000	$ 219,047	$ 1,916,047
Customer Charge Revenue	215,000	-	215,000	-	215,000
Late Payment Charges	15,499		15,499		15,499
Other Revenue	181,758	-	181,758	-	181,758
Total Revenue	$ 2,109,257	$ -	$ 2,109,257	$ 219,047	$ 2,328,304
Operating Revenue Deductions					
Operating Expenses	1,800,177	(202,188)	1,597,989		1,597,989
Depreciation Expense	256,761	15,357	272,118	-	272,118
Miscellaneous Expense	674	-	674	-	674
Taxes Other Than Income	150,717	(1,879)	148,838	8,762	157,600
Total Operating Deductions	$ 2,208,329	$ (188,710)	$ 2,019,619	$ 8,762	$ 2,028,381
Operating Income Before Taxes	$ (99,072)	$ 188,710	$ 89,638	$ 210,285	$ 299,922
Income Taxes					
Amortization of Prepaid Taxes	(6,073)		(6,073)		(6,073)
Federal Income Taxes	31,623	(66,718)	(35,095)	71,497	36,402
Deferred Income Taxes	18,382	(18,382)	-	-	-
Total Income Taxes	$ 43,932	$ (85,100)	$ (41,168)	71,497	$ 30,329
Utility Operating Income	$ (143,004)	$ 273,809	$ 130,805	138,788	$ 269,593
Rate Base	$ 4,604,693	(364,389)	$ 4,240,303		$ 4,240,303
Rate of Return	-3.11%		3.08%		6.36%

BLOCK ISLAND POWER COMPANY

Determination of Revenue Increase
Rate Year Ending May 31, 2006

			Amount	Source
Recommended Rate Base per Division		$	4,240,303	Schedule TSC-2
Required Rate of Return			6.36%	Schedule TSC-1, page 3
Net Operating Income Required		$	269,593	
Net Operating Income at Present Rates			130,805	Schedule TSC-3
Net Income Surplus/(Deficiency)		$	(138,788)	
Revenue Multiplier			1.57828	
Revenue Increase/(Decrease)		$	219,047	
Revenue Increase/(Decrease)		$	219,047	
Rhode Island Gross Earnings Tax	4.0%	$	8,762	
Federal Income Tax	34%		71,497	
Net Income Surplus/(Deficiency)		$	138,788	

BLOCK ISLAND POWER COMPANY

Rate of Return Summary
Rate Year Ending May 31, 2006

Capital Source	Balance (1)	Capitalization Ratio	Cost Rate (2)	Weighted Cost Rate
Total Debt	4,138,521	82.74%	5.50%	4.55%
Common Equity	863,535	17.26%	10.50%	1.81%
Total	$ 5,002,056	100.00%		6.36%

Notes:
(1) Per Schedule WEE-17

(2) Cost rate for debt calculated from Schedule WEE-17

BLOCK ISLAND POWER COMPANY

Summary of Rate Base
Rate Year Ending May 31, 2006

Description	Balance per Company Filing	Division Adjustments (1)	Balance Per Division
Plant in Service	$ 8,002,271	(116,797)	$ 7,885,474
Reserve for Depreciation	(3,296,979)	15,961	(3,281,017)
Net Utility Plant	$ 4,705,293	$ (100,836)	$ 4,604,457
Cash Working Capital	$ 190,197	$ (76,444)	113,753
Materials & Supplies	45,525	21,325	66,850
Prepayments	29,643	(6,488)	23,155
Total Working Capital	$ 265,365	$ (61,606)	$ 203,759
Deferred Credits	(206,533)	-	(206,533)
Accumulated Deferred Income Taxes	(159,432)	(201,947)	(361,379)
Other	-		-
Total Rate Base	$ 4,604,693	$ (364,389)	$ 4,240,303

Note:
(1) Refer to page 2 of this schedule.

BLOCK ISLAND POWER COMPANY

Summary of Adjustments to Rate Base
Rate Year Ending May 31, 2006

	Amount	Source
Rate Base per Company Filing	$ 4,604,693	Schedule WEE-16
Division Adjustments		
Cash Working Capital	(76,444)	Schedule LKM-1
Restate Accumulated Deferred Income Taxes	(201,947)	Schedule TSC-5
Materials & Supplies	21,325	Schedule TSC-6
Prepayments	(6,488)	Schedule TSC-6
Updated Engine No. 25 Cost	(116,797)	Schedule TSC-7
Revised Depreciation Expense	15,961	Schedule TSC-8
Total Division Adjustments	$ (364,389)	
Adjusted Rate Base per Division	$ 4,240,303	

BLOCK ISLAND POWER COMPANY

Summary of Adjustments to Net Income
Rate Year Ending May 31, 2006

	Amount	Source
Net Income per Company	$ (143,004)	Schedule WEE-2
Division Adjustments		
Rate Year Depreciation	(29,935)	Schedule TSC-8
Eliminate Additional Substation Depreciation	19,800	Schedule TSC-9
Labor and Labor Related Expenses	17,198	Schedule TSC-10
Management Fees	50,417	Schedule TSC-11
Actual Health Insurance Premiums	12,262	Schedule TSC-12
Major Engine Maintenance	52,800	Schedule TSC-13
General Insurance Premiums	2,007	Schedule TSC-14
Income Tax Corrections	154,896	Schedule TSC-4
Interest Synchronization	(5,635)	Schedule TSC-4
Total Division Adjustments	$ 273,809	
Adjusted Net Income per Division	$ 130,805	

BLOCK ISLAND POWER COMPANY

Summary of Adjustments to Net Income
Rate Year Ending May 31, 2006

	Revenue	O&M and Other	Depreciation	Taxes Other Than Income	Federal Income Tax	Deferred Federal Income Tax	Invest Tax Credit	Net Operating Income
Net Income per Company	$2,109,257	$1,800,851	$ 256,761	$ 150,717	$ 31,623	$ 18,382	$ (6,073)	$ (143,004)
Division Adjustments								
Rate Year Depreciation	-	-	45,357	-	(15,421)	-	-	(29,935)
Eliminate Additional Substation Depreciation	-	-	(30,000)	-	10,200	-	-	19,800
Labor and Labor Related Expenses	-	(24,179)	-	(1,879)	8,859	-	-	17,198
Management Fees	-	(76,389)	-	-	25,972	-	-	50,417
Actual Health Insurance Premiums	-	(18,579)	-	-	6,317	-	-	12,262
Engine Maintenance	-	(80,000)	-	-	27,200	-	-	52,800
General Insurance Premiums	-	(3,040)	-	-	1,034	-	-	2,007
Income Tax Corrections	-	-	-	-	(136,514)	(18,382)	-	154,896
Interest Synchronization	-	-	-	-	5,635	-	-	(5,635)
Total Division Adjustments	$ -	$ (202,188)	$ 15,357	$ (1,879)	$ (66,718)	$ (18,382)	$ -	$ 273,809
Division Adjusted Net Income	$2,109,257	$1,598,663	$ 272,118	$ 148,838	$ (35,095)	$ -	$ (6,073)	$ 130,805

BLOCK ISLAND POWER COMPANY

Income Tax Reconciliation
Rate Year Ending May 31, 2006
($000)

	Corrected Amount at Present Rates	Division Adjustments	Adjusted per Division at Present Rates	Proposed Revenue Increase	Amount at Proposed Rates
Operating Income before Taxes	$ (99,072)	$ 188,710	$ 89,638	$ 210,285	$ 299,922
Adjustments to Taxable Income					
Interest Expense	(209,431)	16,573	(192,857)	-	(192,857)
Other		-	-	-	-
Total Adjustments	$ (209,431)	$ 16,573	$ (192,857)	$ -	$ (192,857)
Income Subject to Federal Income Tax	$ (308,503)	$ 205,283	$ (103,220)	$ 210,285	$ 107,065
Total Federal Income Tax at 34%	$ (104,891)	$ 69,796	$ (35,095)	$ 71,497	$ 36,402
Less: Bracket Savings		-	-	-	-
Current Federal Income Tax	$ (104,891)	$ 69,796	$ (35,095)	$ 71,497	$ 36,402
Calculation of Interest Deduction					
Rate Base	$ 4,604,693		$ 4,240,303		$ 4,240,303
Weighted Cost of Debt	4.55%		4.55%		4.55%
Interest Deduction	$ 209,431	$ (16,573)	$ 192,857		$ 192,857
Federal Income Tax Effect at 34%		5,635			
Interest Synchronization Adjustment		$ 5,635			

Docket No. 3655
Schedule TSC-5

BLOCK ISLAND POWER COMPANY

Adjustment to Restate Accumulated Deferred Income Taxes
to Reflect 34 Percent Marginal Tax Rate
Rate Year Ending May 31, 2006

		Total Adjustment to Test Year Balance
Average Balance of Deferred Income Taxes per Company Filing Based on 15% Tax Rate (1)	$	159,432
Divide by Tax Rate		15%
Average Balance of Underlying Timing Differences	$	1,062,878
Marginal Federal Income Tax Rate		34%
Restated Balance of Deferred Federal Income Taxes	$	361,379
Adjustment to Rate Base	$	(201,947)

Note:
(1) Per Schedule WEE-13 and responses to DIV 1-49 and 1-50.

Docket No. 3655
Schedule TSC-6

BLOCK ISLAND POWER COMPANY

Adjustment to Materials and Supplies
and Prepayments to Reflect Average Balances
Rate Year Ending May 31, 2006

	Materials and Supplies (1)	Prepaid Insurance (2)	Prepaid Other (1)	Prepaid Management Fee (1)
June	$ 54,358	$ 3,586	2,220	20,000
July	58,366	(376)	2,220	20,000
August	60,977	16,916	2,220	20,000
September	64,900	13,282	2,220	20,000
October	67,129	8,464	2,220	20,000
November	67,129	42,905	2,220	20,000
December	68,090	48,060	2,220	20,000
January	78,126	39,933	2,220	20,000
February	78,269	31,806	2,220	20,000
March	78,269	23,679	2,220	20,000
April	81,065	15,552	2,220	20,000
May	45,525	7,424	2,220	16,000
Total	$ 802,203	$ 251,231	$ 26,640	$ 236,000
Average Balance	$ 66,850	$ 20,936	$ 2,220	$ 19,667
Division Adjustment	-	-	-	(19,667)
Adjusted Balance	$ 66,850	$ 20,936	$ 2,220	$ -
Amount Per Company (3)	45,525	7,424	2,220	20,000
Adjustment to Rate Base	$ 21,325	$ 13,512	$ -	$ (20,000)

Notes:

(1) Monthly balances per response to DIV 1-62.

(2) Balances for January through April per response to DIV 1-62 were unchanged from December. These balances have been adjusted to reflect uniform drawdown of prepayment between December and May.

(3) Per Schedule WEE-16 and respnse to DIV 1-62.

Docket No. 3655
Schedule TSC-7

BLOCK ISLAND POWER COMPANY

Adjustment to Reflect Updated
Replacement Plan for Engine No. 25
Rate Year Ending May 31, 2006

		Amount
Updated Cost Estimate (1)		
Initial Costs (FY 2005)	$	405,114
Engine Purchase (Rate Year)		175,000
Total Cost	$	580,114
Average Rate Year Balance (2)	$	492,614
Original Estimated Cost (Interim Year) (3)		609,411
Adjustment to Average Rate Year Plant in Service	$	(116,797)

Notes:

(1) Per response to DIV 1-61 and informal follow-up.

(2) Based on initial costs in interim year plus one-half of rate year engine purchase cost.

(3) Per testimony of Walter Edge at page 28.

Docket No. 3655
Schedule TSC-8

BLOCK ISLAND POWER COMPANY

Adjustment to Reflect Rate Year Depreciation Expense
Rate Year Ending May 31, 2006

	Service Life (1)	End of Test Year Balance (2)	Additions	End of Rate Year Balance (1)	Rate Year Depreciation Expense (3)
Access Electric	20	$ 87,252	$ -	$ 87,252	$ 3,308
Aid in Construction	20	181,697	-	181,697	6,613
Communication Equipment	15	262,680	-	262,680	16,609
Fuel System	16	374,609	-	374,609	21,981
Furniture & Fixtures	Fully Depr.	1,327	-	1,327	-
Land and Land Rights	Fully Depr.	79,610	-	79,610	-
Lines	20	190,978	-	190,978	7,295
Meters	20	159,663	-	159,663	3,512
Office Furniture and Equipment	5	87,684	15,000	102,684	808
Oil Polution Equipment	Fully Depr.	63,005	-	63,005	-
Overhead Devices	20	588,906	315,000	903,906	22,464
Poles	20	199,892	-	199,892	4,713
Generation Equipment (4)	20	2,547,578	580,114	3,127,692	143,685
Street Lighting	20	16,292	-	16,292	324
Structures and Improvements	40	263,189	-	263,189	1,610
Structures and Improvements-Substations	40	1,661,363	55,000	1,716,363	43,948
Tools, Shop and Garage Equipment	7	25,431	-	25,431	322
Transportation Equipment	16	460,056	-	460,056	8,886
Underground	20	744,886	-	744,886	28,230
Vaults	20	28,971	-	28,971	870
Negative Fixed Assets (Contributions In Aid)	20	(861,209)	-	(861,209)	(43,060)
Total Amount		$ 7,163,860	$ 965,114	$ 8,128,974	$ 272,118
Depreciation Expense per Company Filing					226,761
Adjustment to Depreciation Expense					$ 45,357

Depreciation Reserve Effect	Amount
Rate Year Depreciation Accrual per Company (1)	$ 304,040
Rate Year Depreciation Accrual per Division	272,118
Adjustment to End of Rate Year Reserve Balance	$ (31,922)
Adjustment to Average Rate Base	$ 15,961

Notes:

(1) Per Responses to DIV 1-43, 1-44 and 4-8, except as noted.

(2) Per Schedule WEE-9.

(3) Per response to DIV 4-8, except where noted.

(4) Additions have been adjusted to reflect updated costs per Schedule TSC-7. Depreciation has been calculated based on 20 year life and one half year's depreciation has been included on the rate year portion of additions.

BLOCK ISLAND POWER COMPANY

Adjustment to Eliminate
Additional Substation Depreciation
Rate Year Ending May 31, 2006

	Amount
Proposed Additional Depreciation per Company (1)	$ 30,000
Amount per Division	-
Adjustment to Depreciation Expense	$ (30,000)

Note:
(1) Per Schedule WEE-11.

Docket No. 3655
Schedule TSC-10

BLOCK ISLAND POWER COMPANY

Adjustment to Labor and Related Costs
Rate Year Ending May 31, 2006

	FY 2005 Wages (1)	FY 2006 Wages (2)	Profit Sharing	FICA & Medicare	Unemployment Tax
		3.0%	3.0%	7.65%	
Alpers	$ 40,817	$ 42,042	$ 1,261	3,216	$ 266
Foote	36,203	37,289	1,119	2,853	266
Fowler	41,601	42,849	1,285	3,278	266
Hiccox	34,127	37,198	1,116	2,846	266
Martin	61,345	63,185	1,896	4,834	266
Milner	65,438	67,401	2,022	5,156	266
Sovoie	37,129	38,243	1,147	2,926	266
Wagner	84,844	87,389	2,622	6,685	266
Total	$ 401,504	$ 415,597	$ 12,468	$ 31,793	$ 2,128
Capitalized Labor (3)	$ (15,659)	(16,128)	(484)	(1,234)	$ (83)
Net Labor Expense	$ 385,845	$ 399,468	$ 11,984	$ 30,559	$ 2,045
Amount Per Company (4)		422,943	12,688	32,355	2,128
Adjustment to Expense		$ (23,475)	$ (704)	$ (1,796)	$ (83)

Notes:

(1) Per Schedule WEE-4a and response to DIV 4-3.

(2) Reflects 3% increase for all employees except Hiccox, for which a 9% increase is included.

(3) FY 2005 and FY 2006 capitalized labor calculated by applying 5% and 3% wage increases to prior year amounts.

(4) Per Schedules WEE-4, WEE-6 and WEE-10.

Docket No. 3655
Schedule TSC-11

BLOCK ISLAND POWER COMPANY

Adjustment to Proposed Management Fee
Rate Year Ending May 31, 2006

Pascoag		Amount
Comparable Management Compensation (1)		
Management Salaries		224,500
Retirement Contribution at 10%		22,500
Total Pascoag Management Compensation	$	247,000
BIPCO		
General Manager Salary (Wagner) (2)	$	84,844
Retirement Contribution at 3%		2,545
Bookkeeping & Financial (3)		24,000
Management Compensation before Management Fee	$	111,389
Management Fee		212,000
Total BIPCO Management Compenation	$	323,389
Adjustment to Claimed Management Fee	$	(76,389)

Notes:

(1) Based on compensation of General Manager, Assistant General Manager and Customer Service and Accounting Manager at Pascoag Utilities for 2005.

(2) FY 2004-05 salary per Schedule WEE-4a.

(3) Based on stipend to Walter Edge for bookkeeping and financial advice for FY 2004-05 per minutes of May 15, 2004 Board of Directors Meeting.

Docket No. 3655
Schedule TSC-12

BLOCK ISLAND POWER COMPANY

Adjustment to Medical and Dental Insurance Expense
Rate Year Ending May 31, 2006

	Monthly Medical Premium (1)	Monthly Dental Premium (2)	Total Annual Premiums
Alpers	$ 457.30	$ 34.98	$ 5,907
Foote	731.68	103.83	10,026
Fowler	1,211.85	103.83	15,788
Hiccox	457.30	34.98	5,907
Martin	1,074.66	103.83	14,142
Milner	1,211.85	103.83	15,788
Sovoie	1,211.85	103.83	15,788
Wagner	1,211.85	103.83	15,788
Casazza	1,074.66	-	12,896
McGinnes	457.30	34.98	5,907
Total	$ 9,100.30	$ 727.92	$ 117,939
Months	12	12	
Annual Expense	$ 109,204	$ 8,735	$ 117,939
Amount Per Company (3)	127,689	8,829	136,518
Adjustment to Expense	$ (18,485)	$ (94)	$ (18,579)

Notes:

(1) Reflects Blue Cross/Blue Shield Premiums for April 2005 through March 2006 per response to DIV 4-6.

(2) Reflects Delta Dental Premiums for April 2005 through March 2007 per response to DIV 4-6.

(3) Per Schedule WEE-5b. Does not include Medical Reimbursement for Slate.

Docket No. 3655
Schedule TSC-13

BLOCK ISLAND POWER COMPANY

Adjustment to Major Engine Maintenance Expense
Rate Year Ending May 31, 2996

Engine Maintenance Expenes (1)		Amount
Fiscal Year 2000	$	26,460
Fiscal Year 2001		30,106
Fiscal Year 2002		34,201
Fiscal Year 2003		113,347
Fiscal Year 2004		95,931
Total	$	300,045
Five Year Average	$	60,009
Two Year Average (FY2003 - FY2004)	$	104,639
Division Recommended Allowance	$	110,000
Amount Per Company Filing (2)		190,000
Adjustment to Rate Year Expense	$	(80,000)

Notes:
(1) Per Schedule DGB-2

(2) Per Schedule WEE-3.

Docket No. 3655
Schedule TSC-14

BLOCK ISLAND POWER COMPANY

Adjustment to Reflect Actual
General Insurance Premiums
Rate Year Ending May 31, 2006

		Amount
Insurance Premiums for Policy Year Ended June 27, 2005 (1)	$	111,313
Increase for Policy Year Ended June 27, 2006 (2)		5%
Insurance Premiums for Policy Year Ended June 27, 2006	$	116,879
Rate Year Insurance Expense per Company (1)		119,919
Adjustment to Insurance Expense	$	(3,040)

Note:
(1) Per Schedule WEE-11.

Docket No. 3655
Schedule LKM-1

BLOCK ISLAND POWER COMPANY

Cash Working Capital Summary
Rate Year Ending May 31, 2006

	Amount	
Cash Working Capital per Division	$ 113,753	
Cash Working Capital per Company	190,197	(1)
Adjustment to Cash Working Capital	$ (76,444)	

Notes:
(1) Schedule DGB-6.

BLOCK ISLAND POWER COMPANY

Calculation of Operating Expenses Working Capital
Rate Year Ending May 31, 2006

	Rate Year Amount	Division Adjustments	Net Amount	Average Daily Expense	Revenue Lag Days (2)	Expense Lag Days	Net Lag Days	Cash Working Capital
Fuel Expenses	$ -	$ - (1)	$ -	$ -	43.71	30.21 (3)	13.50	$ -
Operating & Maintenance Expenses	1,251,659	(175,673)	1,075,986	2,948	43.71	30.21 (3)	13.50	39,802
Payroll	422,943	(23,475)	399,468	1,094	43.71	4.50 (4)	39.21	42,913
General Insurance	119,919	(3,040)	116,879	320	43.71	30.21 (3)	13.50	4,323
Bad Debt	6,330	(6,330)	-	-	43.71	- (3)	43.71	-
Depreciation	256,761	(256,761)	-	-	43.71	-	43.71	-
Total Taxes other than GRT & Deferred Taxes	97,970	2,900	100,870	276	43.71	30.21 (3)	13.50	3,731
Deferred Taxes	18,382	(18,382)	-	-	43.71	- (3)	43.71	-
Gross Receipts Taxes	84,370	8,762	93,132	255	43.71	(41.19) (5)	84.90	21,663
Interest Expense	209,431	(16,573)	192,858	528	43.71	41.21 (6)	2.50	1,321
	$ 2,467,765	$ (488,572)	$ 1,979,193					$ 113,753

Notes:
(1) Per Response to Division 1-2, fuel adjustment clause contain a separate financing cost factor.
(2) Schedule 7.
(3) Schedule 3.
(4) Schedule DGB-6c.
(5) Schedule 4.
(6) Schedule 5.

BLOCK ISLAND POWER COMPANY

Calculation of Operating Expenses Payment Lag
Rate Year Ending May 31, 2006

Number of days per Year	365	
Number of Month per Year	12	
Average number of days per month	30.42	
Service Period Divisor	2	
Average Service Period Number of Days	15.21	(1)
Payment Lag Days	15.00	(2)
Operating Expense Payment Lag	30.21	

Notes:
(1) To reflect service period lag.
(2) Schedule DGB-6.

BLOCK ISLAND POWER COMPANY

Calculation of Average Gross Receipts Tax Lead Days
Rate Year Ending May 31, 2006

	GRT Accrued	
2002 GRT Lead Days	50	(1)
2003 GRT Lead Days	33	(2)
Average GRT Lead (Days)	41	

Notes:
(1) Schedule 4, page 2.
(2) Schedule 4, page 3.

BLOCK ISLAND POWER COMPANY

Calculation of 2002 GRT Lead/Lag Days
Rate Year Ending May 31, 2006

	2002 Revenue	2002 GRT Accrued	2002 GRT Paid		GRT (Payable) / Prepaid
January-02	$ 125,433.16	$ 5,017.33	$ -		$ (5,017.33)
February-02	102,574.09	4,102.96	-		(9,120.29)
March-02	116,268.69	4,650.75	41,524.00	(1)	27,752.96
April-02	118,651.44	4,746.06	-		23,006.90
May-02	139,464.67	5,578.59	-		17,428.31
June-02	347,661.07	13,906.44	62,286.00	(1)	65,807.87
July-02	443,306.05	17,732.24	-		48,075.63
August-02	444,793.37	17,791.73	-		30,283.90
September-02	368,174.30	14,726.97	-		15,556.93
October-02	162,679.39	6,507.18	-		9,049.75
November-02	149,528.10	5,981.12	-		3,068.63
December-02	141,487.43	5,659.50	-		(2,590.87)
January-03	-	-	-		(2,590.87)
February-03	-	-	-		(2,590.87)
March-03	-	-	2,590.87	(2)	(0.00)
	$ 2,660,021.76	$ 106,400.87	$ 106,400.87		$ 218,120.65

Average Monthly GRT	$ 14,541.38
Total Annual GRT	$ 106,400.87
Prepaid Percentage	14%
Annual Number of Days	365
2002 GRT Lead Days	50

Notes:

(1) Per Response to Division 1-8, These are the actual amounts paid in March & June. The Company adjusted these amounts as if no true-up (or shortfall) occurred after year-end.

(2) Per Response to Division 1-8, The shortfall is due on or before the subsequent March 1st.

BLOCK ISLAND POWER COMPANY

Calculation of 2003 GRT Lead/Lag Days
Rate Year Ending May 31, 2006

	2003 Revenue	2003 GRT Accrued	2003 GRT Paid		GRT (Payable) / Prepaid
January-03	$ 143,975.46	$ 5,759.02	$ -		$ (5,759.02)
February-03	154,452.25	6,178.09	-		(11,937.11)
March-03	132,935.79	5,317.43	43,380.00	(1)	26,125.46
April-03	150,597.14	6,023.89	-		20,101.57
May-03	209,200.04	8,368.00	-		11,733.57
June-03	349,729.63	13,989.19	65,070.00	(1)	62,814.38
July-03	473,124.56	18,924.98	-		43,889.40
August-03	539,037.93	21,561.52	-		22,327.88
September-03	308,949.11	12,357.96	-		9,969.92
October-03	162,994.84	6,519.79	-		3,450.13
November-03	149,550.45	5,982.02	-		(2,531.89)
December-03	140,440.87	5,617.63	-		(8,149.52)
January-04	-	-	-		(8,149.52)
February-04	-	-	-		(8,149.52)
March-04	-	-	8,149.52	(2)	0.00
	$ 2,914,988.07	$ 116,599.52	$ 116,599.52		$ 172,034.77
Average Monthly GRT					$ 10,382.38
Total Annual GRT					$ 116,599.52
Prepaid Percentage					9%
Annual Number of Days					365
2003 GRT Lead Days					33

Notes:
(1) Per Response to Division 1-8, These are the actual amounts paid in March & June. The Company adjusted these amounts as if no true-up (or shortfall) occurred after year-end.
(2) Per Response to Division 1-8, The shortfall is due on or before the subsequent March 1st.

BLOCK ISLAND POWER COMPANY

Calculation of Average Interest Lag
Rate Year Ending May 31, 2006

	Amount	Lag Days		Weighted Amount
RUS Debt	$ 3,078,109	45.00	(1)	$ 138,514,905
Non-RUS Debt	1,060,412	30.21	(2)	32,033,279
	$ 4,138,521			$ 170,548,184
Average Lag Days		41.21		

Notes:

(1)	Service Period Days	90	Per response to Division 1-6, RUS debt is paid quarterly.
	Divisor	2	
	Lag Days	45.00	Midpoint of # of days in quarter to end of quarter.

(2) Per Response to Division 1-6, WTC loan is paid monthly on the 15th of each month. Therefore, there is a 30-day service period and a 15-day payment lag that results in 15.21 lag days from midpoint of the service period to the end plus the 15-day payment lag.

BLOCK ISLAND POWER COMPANY

Calculation of Average Revenue Lag Days
Rate Year Ending May 31, 2006

	Lag Days	
Average Monthly Service Period Days	15.21	(1)
Billing Lag Days	15.00	(2)
Collection Lag Days	13.50	(2)
Average Revenue Lag Days	43.71	

Notes:
(1) Schedule 3.
(2) Schedule DGB-6a.

Block Island Power Company
Docket 3655

Rate Design Summary - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

			Base Revenue				Total Revenue			
Ln No	Rate Classification	Annual KWH	Current Rates	Proposed Rates	Increase $	Increase %	Current Rates	Proposed Rates	Increase $	Increase %
1	Residential Service Rate "R"	4,273,390	$ 732,066	$ 804,320	$ 72,254	9.9%	$ 1,128,539	$ 1,200,794	$ 72,254	6.4%
2	Commercial General Service - Rate "G"	1,548,103	$ 294,346	$ 316,356	$ 22,010	7.5%	$ 440,454	$ 462,464	$ 22,010	5.0%
3	Commercial Demand Service - Rate "D"	4,544,181	$ 746,787	$ 861,214	$114,427	15.3%	$ 1,151,122	$ 1,265,549	$114,427	9.9%
4	Public Authority Demand - Rate "P"	700,912	$ 112,760	$ 121,158	$ 8,398	7.4%	$ 176,392	$ 184,790	$ 8,398	4.8%
5	Public Authority Non-Demand - Rate "P"	78,245	$ 12,879	$ 13,845	$ 966	7.5%	$ 19,983	$ 20,949	$ 966	4.8%
6	Street Lighting Service - Rate "S"	44,238 *	$ 13,163	$ 14,154	$ 991	7.5%	$ 13,163	$ 17,923	$ 4,760	36.2%
7	Total Revenue from Sales	11,144,831	$ 1,912,001	$ 2,131,047	$219,047	11.5%	$ 2,929,654	$ 3,152,469	$222,816	7.6%
8	Other Revenue		$ 197,257	$ 197,257	$ -	0.0%	$ 197,257	$ 197,257	$ -	0.0%
9	TOTAL REVENUE		$ 2,109,257	$ 2,328,304	$219,047	10.4%	$ 3,126,910	$ 3,349,726	$222,816	7.1%
10	TARGET REVENUE				$219,047					
11	Rate Design Variance				$ (0)					

* Not applicable under current rates.

Block Island Power Company
Docket 3655

Residential (Rate "R") Rate Design - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Type of Charge	Service Units	Current Rate	Revenue at Current Rate	Proposed Rate	Revenue at Proposed Rate	Increase $	Increase %
	Customer Charges							
1	Summer	5,200	$ 10.00	$ 52,000	$ 11.00	$ 57,200	$ 5,200	10.0%
2	Winter	10,471	$ 10.00	$ 104,710	$ 11.00	$ 115,181	$ 10,471	10.0%
3	Total	15,671		$ 156,710		$ 172,381	$ 15,671	10.0%
	Energy Charges							
4	Summer	1,931,232	$ 0.1945	$ 375,625	$ 0.2132	$ 411,739	$ 36,114	9.6%
5	Winter	2,342,158	$ 0.0738	$ 172,851	$ 0.0809	$ 189,481	$ 16,629	9.6%
6	Total	4,273,390		$ 548,476		$ 601,219	$ 52,743	9.6%
	System Charges							
7	Summer Only	1,536	$ 17.50	$ 26,880	$ 20.00	$ 30,720	$ 3,840	14.3%
8	**Subtotal Base Revenue**			$ 732,066		$ 804,320	$ 72,254	**9.9%**
9	Fuel Surcharge	4,273,390	$ 0.0928	$ 396,473	$ 0.0928	$ 396,473	$ -	0.0%
10	**Rate "R" Total**			$ 1,128,539		$ 1,200,794	$ 72,254	6.4%

Block Island Power Company
Docket 3655

Commercial General (Rate "G") Rate Design - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Type of Charge	Service Units	Current Rate	Revenue at Current Rate	Proposed Rate	Revenue at Proposed Rate	Increase $	Increase %
	Customer Charges							
1	Summer	1,201	$ 10.00	$ 12,010	$ 11.00	$ 13,211	$ 1,201	10.0%
2	Winter	2,405	$ 10.00	$ 24,050	$ 11.00	$ 26,455	$ 2,405	10.0%
3	Total	3,606		$ 36,060		$ 39,666	$ 3,606	10.0%
	Energy Charges							
4	Summer	751,752	$ 0.2200	$ 165,385	$ 0.2357	$ 177,188	$ 11,803	7.1%
5	Winter	796,351	$ 0.1000	$ 79,635	$ 0.1071	$ 85,289	$ 5,654	7.1%
6	Total	1,548,103		$ 245,021		$ 262,477	$ 17,457	7.1%
	System Charges							
7	Summer Only	379	$ 35.00	$ 13,265	$ 37.50	$ 14,213	$ 948	7.1%
8	**Subtotal Base Revenue**			$ 294,346		$ 316,356	$ 22,010	7.5%
9	Fuel Surcharge	1,548,103	$ 0.0944	$ 146,108	$ 0.0944	$ 146,108	$ -	0.0%
10	**Rate "G" Total**			$ 440,454		$ 462,464	$ 22,010	5.0%

Block Island Power Company
Docket 3655

Commercial Demand (Rate "D") Rate Design - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Type of Charge	Service Units	Current Rate	Revenue at Current Rate	Proposed Rate	Revenue at Proposed Rate	Increase $	Increase %
	Customer Charges							
1	Summer	388	$ 15.00	$ 5,820	$ 16.50	$ 6,402	$ 582	10.0%
2	Winter	774	$ 15.00	$ 11,610	$ 16.50	$ 12,771	$ 1,161	10.0%
3	Total	1,162		$ 17,430		$ 19,173	$ 1,743	10.0%
	Energy Charges							
4	Summer	2,581,350	$ 0.1684	$ 434,699	$ 0.1942	$ 501,298	$ 66,599	15.3%
5	Winter	1,962,831	$ 0.0840	$ 164,878	$ 0.0969	$ 190,198	$ 25,321	15.4%
6	Total	4,544,181		$ 599,577		$ 691,496	$ 91,919	15.3%
	Demand Charges							
7	Summer	6,551	$ 15.00	$ 98,265	$ 17.40	$ 113,987	$ 15,722	16.0%
8	Winter	6,303	$ 5.00	$ 31,515	$ 5.80	$ 36,557	$ 5,042	16.0%
9	Total	12,854		$ 129,780		$ 150,545	$ 20,765	16.0%
10	**Subtotal Base Revenue**			$ 746,787		$ 861,214	$ 114,427	15.3%
11	Fuel Surcharge	4,544,181	$ 0.0890	$ 404,335	$ 0.0890	$ 404,335	$ -	0.0%
12	**Rate "D" Total**			$ 1,151,122		$ 1,265,549	$ 114,427	9.9%

Block Island Power Company
Docket 3655

Public (Rate "P") Demand Rate Design - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Type of Charge	Service Units	Current Rate	Revenue at Current Rate	Proposed Rate	Revenue at Proposed Rate	Increase $	Increase %
	Customer Charges							
1	Summer	72	$ 15.00	$ 1,080	$ 16.50	$ 1,188	$ 108	10.0%
2	Winter	144	$ 15.00	$ 2,160	$ 16.50	$ 2,376	$ 216	10.0%
3	Total	216		$ 3,240		$ 3,564	$ 324	10.0%
	Energy Charges							
4	Summer	241,320	$ 0.16360	$ 39,480	$ 0.1739	$ 41,966	$ 2,486	6.3%
5	Winter	459,592	$ 0.08180	$ 37,595	$ 0.0869	$ 39,939	$ 2,344	6.2%
6	Total	700,912		$ 77,075		$ 81,904	$ 4,830	6.3%
	Demand Charges							
7	Summer Only	1,350	$ 15.00	$ 20,250	$ 16.50	$ 22,275	$ 2,025	10.0%
8	Winter	2,439	$ 5.00	$ 12,195	$ 5.50	$ 13,415	$ 1,220	10.0%
9	Total	3,789		$ 32,445		$ 35,690	$ 3,245	10.0%
10	**Subtotal Base Revenue**			$ 112,760		$ 121,158	$ 8,398	7.4%
11	Fuel Surcharge	700,912	$ 0.0908	$ 63,633	$ 0.0908	$ 63,633	$ -	0.0%
12	**Rate "P" Demand Total**			$ 176,392		$ 184,790	$ 8,398	4.8%

Block Island Power Company
Docket 3655

Public (Rate "P") Non-Demand Rate Design - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Type of Charge	Service Units	Current Rate	Revenue at Current Rate	Proposed Rate	Revenue at Proposed Rate	Increase $	Increase %
	Customer Charges							
1	Summer	52	$ 10.00	$ 520	$ 11.00	$ 572	$ 52	10.0%
2	Winter	104	$ 10.00	$ 1,040	$ 11.00	$ 1,144	$ 104	10.0%
3	Total	156		$ 1,560		$ 1,716	$ 156	10.0%
	Energy Charges							
4	Summer	25,947	$ 0.2000	$ 5,189	$ 0.2155	$ 5,592	$ 402	7.7%
5	Winter	52,298	$ 0.1000	$ 5,230	$ 0.1078	$ 5,638	$ 408	7.8%
6	Total	78,245		$ 10,419		$ 11,229	$ 810	7.8%
	System Charges							
7	Summer Only	24	$ 37.50	$ 900	$ 37.50	$ 900	$ -	0.0%
8	**Subtotal Base Revenue**			$ 12,879		$ 13,845	$ 966	7.5%
9	Fuel Surcharge	78,245	$ 0.0908	$ 7,104	$ 0.0908	$ 7,104	$ -	0.0%
10	**Rate "P" Non-Demand Total**			$ 19,983		$ 20,949	$ 966	4.8%

Block Island Power Company
Docket 3655

Street Light (Rate "S") Rate Design - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Type of Charge	Service Units	Current Rate	Revenue at Current Rate	Proposed Rate	Revenue at Proposed Rate	Increase $	Increase %
1	Lamp Charge	852	$ 15.45	$ 13,163	$ 13.29	$ 11,323	$ (1,840)	-14.0%
2	Energy Charge	44,238	$ -	$ -	$ 0.0640	$ 2,831	$ 2,831	NM
3	Subtotal Base Revenue			$ 13,163		$ 14,154	$ 991	7.5%
4	Fuel Surcharge	44,238 *	$ -	$ -	$ 0.0852	$ 3,769	$ 3,769	NM
5	**Rate "S" Total**			$ 13,163		$ 17,923	$ 4,760	36.2%

* Not applicable under current rates.

Block Island Power Company
Docket 3655

Revenue Increase by Type of Charge - Division Rate Design & Settlement Revenue Requirement
Rate Year - Current Seasonal Period Definitions

Ln No	Rate Classification	Billing Units	Current Revenue	Proposed Revenue	Increase $	Increase %
1	**Total Customer Charge Revenue**	20,811	$ 215,000	$ 236,500	$ 21,500	10.0%
2	**Total Energy Charge Revenue**	11,189,069	$ 1,480,567	$ 1,651,158	$ 170,590	11.5%
3	**Total Demand Charge Revenue**	16,643	$ 162,225	$ 186,234	$ 24,009	14.8%
4	**Total System Charge Revenue**	1,939	$ 41,045	$ 45,833	$ 4,788	11.7%
5	**Total Street Lighting Charge Revenue**	852	$ 13,163	$ 11,323	$ (1,840)	-14.0%
6	**Total Revenue from Sales**		**$ 1,912,001**	**$ 2,131,047**	**$ 219,047**	**11.5%**
7	**Fuel Surcharge**	11,189,069	$ 1,017,653	$ 1,021,422	$ 3,769 #	0.4%
8	**Late Charge Revenue**		$ 15,499	$ 15,499	$ -	0.0%
9	**Other Revenue**		$ 181,758 *	$ 181,758	$ -	0.0%
10	**TOTAL REVENUE**		**$ 3,126,911**	**$ 3,349,726**	**$ 222,816**	**7.1%**

* Other Revenue (Per Catlin TSC-1, page 1 of 2)

Removal for Non-Payment	$ 550
Interest Income	$ 1,489
Rent - Lease	$ 175,719
Miscellaneous Revenue	$ 4,000
Total	$ 181,758

Fuel Surcharge revenue from Street Lighting would result in minor reductions in Fuel Surcharges for other classes.

BLOCK ISLAND POWER COMPANY
Block Island, Rhode Island

R.I. PUC No. 3655
Sheet No. 1
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Effective: June 1, 2005

RESIDENTIAL SERVICE

RATE "R"

AVAILABILITY

Available only for low voltage service where the use is predominately for residential purposes.

Available in individual residences and in individually metered dwelling units in multifamily dwellings.

Available in churches and adjacent buildings operated in connection therewith.

Available only if Customer takes his entire electric energy requirements from the Company.

Not available if customer makes use of auxiliary generating equipment in lieu of service available from the Company.

Not available for residential premises in which three (3) or more rooms are available for hire.

Not available to any customer whose 15-minute interval metered demand is found to exceed eight (8) kilowatts at any time during the period June 1 through September 30 of any year.

Not available for temporary, auxiliary or emergency service.

Not available to Residential Customers using more than 2,500 kilowatt-hours in any calendar month or more than 20,000 kilowatt-hours in any year. Customers for whom usage in excess of these limits is recorded will be served under the Company's Demand Metered General Service rate schedule, Rate "D".

MONTHLY RATE

The Monthly rate for service will be the sum of the following four charges for each month:

		For Service During the months of June – September	For Service During the months of October – May
1.	Customer Charge	\$11.00 per month	\$11.00 per month
2.	System Charge	\$20.00 per month	None
3.	Energy Charge	21.32¢ per kWh	8.09¢ per kWh
4.	Fuel Adjustment Charge	As determined in accordance with Rider "FAC"	

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Sheet No. 2
Canceling R.I. PUC No. 1998
Effective: June 1, 2005

APPLICATION OF SYSTEM CHARGE

The System Charge will be applied in each summer billing month (June through September) to each customer whose kilowatt-hour (kWh) use in the billing month exceeds two (2) times the customer's Average Kilowatt-Hour Use in the preceding eight (8) winter billing months (October through May). Average Kilowatt-Hour Use for the preceding winter billing months is computed by dividing the aggregate use for each customer during the most recent October - May billing months by eight (8). The denominator of eight (8) is used irrespective of the number of months in which the customer received electric service or for which the customer was billed during that period.

RIDER "FAC" - FUEL ADJUSTMENT CHARGE

Charges for fuel costs computed in accordance with the provisions of the Fuel Adjustment Charge Rider "FAC", combined with the other charges under the provisions of this schedule constitute the total charge for service.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "Terms and Conditions" for furnishing electric service.

BLOCK ISLAND POWER COMPANY
Block Island, Rhode Island

R.I. PUC No. 3655
Sheet No. 1
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Effective: June 1, 2005

GENERAL SERVICE

RATE "G"

AVAILABILITY

Available for all uses of electric service at secondary voltage levels except where Customer electric devices (or groups of electric devices which start together) have a starting load in excess of 15 KVA.

Available only if Customer takes his entire electric energy requirements from the Company.

Not available if customer makes use of auxiliary generating equipment in lieu of service available from the Company.

Not available for temporary, auxiliary or emergency service.

Not available to customers having metered demands in excess of eight (8.0) kW or energy use for a twelve-month period in excess of 20,000 kWh. Customers for whom usage in excess of these limits is recorded will be served under the Company's Demand Metered General Service rate schedule, Rate "D".

MONTHLY RATE

The Monthly rate for service will be the sum of the following five (5) charges for each month:

		For Service During the months of June – September	For Service During the months of October – May
1.	Customer Charge	\$11.00 per month	\$11.00 per month
2.	System Charge	\$37.50 per month	None
3.	Energy Charge	23.57¢ per kWh	10.71¢ per kWh
4.	Fuel Adjustment Charge	As determined in accordance with Rider "FAC"	

APPLICATION OF SYSTEM CHARGE

The System Charge will be applied in each summer billing month (June through September) to each customer whose kilowatt-hour (kWh) use in the billing month exceeds two (2) times the customer's Average Kilowatt-Hour Use in the preceding eight (8) winter billing months (October through May). Average Kilowatt-Hour Use for the preceding winter billing months is computed by dividing the aggregate use for each customer during the most recent October – May billing months by eight (8). The denominator of eight (8) is used irrespective of the number of months in which the customer received electric service or for which the customer was billed during that period.

RIDER "FAC" – FUEL ADJUSTMENT CHARGE

Charges for fuel costs computed in accordance with the provision of the Fuel Adjustment Charge – Rider "FAC", combined with the other charges under the provisions of this schedule constitute the total charge for service.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "Terms and Conditions" for furnishing electric service.

DEMAND-METERED GENERAL SERVICE

RATE "D"

AVAILABILITY

Available for all uses of electric service at secondary voltage levels except where Customer electric devices (or groups of electric devices which start together) have a starting load in excess of 15 KVA.

Available for auxiliary or emergency service.

Not available to any customer whose monthly metered demands fail to exceed 4.0 kW for any month within a twenty-four (24) month period.

MONTHLY RATE

The Monthly rate for service will be the sum of the following five (5) charges for each month:

		For Service During the months of June – September	For Service During the months of October – May
1.	Customer Charge	\$16.50 per month	\$16.50 per month
2.	Demand Charge	\$17.40 per kW	\$5.80 per kW
3.	Energy Charge	19.42¢ per kWh	9.69¢ per kWh
4.	Fuel Adjustment Charge	As determined in accordance with Rider "FAC"	

RIDER "FAC" - FUEL ADJUSTMENT CHARGE

Charges for fuel costs computed in accordance with the provisions of the Fuel Adjustment Charge – Rider "FAC", combined with the other charges under the provisions of this schedule constitute the total charge for service.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "Terms and Conditions" for furnishing electric service.

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PUBLIC AUTHORITY SERVICE

RATE "P"

AVAILABILITY

Available for uses of electric service by a Public Authority Customer at secondary voltage levels except where Customer electric devices (or groups of electric devices which start together) have a starting load in excess of 15 KVA.

Available only if Customer takes his entire electric energy requirements from the Company.

Available only for metered service.

Not available if customer makes use of auxiliary generating equipment in lieu of service available from the Company.

Not available for temporary, auxiliary or emergency service.

MONTHLY RATE

The Monthly rate for service will be the sum of the following five (5) charges for each month:

		For Service During the months of June – September	For Service During the months of October – May
1.	Customer Charge		
	a. Non-Demand	\$11.00 per month	\$11.00 per month
	b. Demand Metered	\$16.50 per month	\$16.50 per month
2.	Demand Charges	\$16.50 per kW	\$5.50 per kW
3.	Energy Charge		
	a. Non-Demand	21.55¢ per kWh	10.78¢ per kWh
	b. Demand-Metered	17.39¢ per kWh	8.69¢ per kWh
4.	System Charge	\$37.50 per month	None
5.	Fuel Adjustment Charge	As determined in accordance with Rider "FAC"	

APPLICATION OF SYSTEM CHARGE

The System Charge will be applied in each summer billing month (June through September) to each Non-Demand customer whose kilowatt-hour (kWh) use in the billing month exceeds two (2) times the customer's Average Kilowatt-Hour Use in the preceding eight (8) winter billing months (October through May). Average Kilowatt-Hour Use for the preceding winter billing months is computed by dividing the aggregate use for each customer during the most recent October - May billing months by eight (8). The denominator of eight (8) is used irrespective of the number of months in which the customer received electric service or for which the customer was billed during that period. The System Charge is not applicable to Demand-Metered customers.

APPLICATION OF DEMAND CHARGE

The Demand Charge will be applied to each customer having demand metering installed by, or for, the Company, for whom at least one metered demand in excess of eight (8.0) kW has been recorded within the most recent 24 months. Demand metering equipment will be installed for any customer whose energy use for a consecutive twelve-month period in excess of 20,000 kWh. Customers for whom usage in excess of (8.0) kW during any 15-minute interval exceeds eight kW (8.0) or for whom metered annual kWh use exceeds 20,000 kWh will be transferred to demand billing status.

RIDER "FAC" - FUEL ADJUSTMENT CHARGE

Charges for fuel costs computed in accordance with the provisions of the Fuel Adjustment Charge-Rider "FAC", combined with the other charges under the provisions of this schedule constitute the total charge for service.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "Terms and Conditions" for furnishing electric service.

STREET LIGHTING SERVICE

RATE "S"

AVAILABILITY

Available for all street lighting and pole-mounted flood lighting purposes on the Company's existing distribution lines suitable for supplying the service requested. The Company will furnish, maintain, and operate mercury vapor lamps of 6000 mean lumens.

Available for the supply of lighting from dusk to dawn using suitable control apparatus furnished, maintained, and operated by the Company.

Available only for installations which use transformers and circuits energized for Residential, Commercial, Public Authority, or other non-lighting purposes.

Not available for a newly installed street lighting fixture on an existing Company-owned pole supplied from an existing secondary circuit where no street lighting fixture(s) is currently installed.

MONTHLY RATE

Where street lighting fixtures are mounted on wood poles and supplied by overhead type construction of circuits:

Mercury Vapor Lamps	Monthly Charge
6000 mean lumen	$15.45

BILLING

Charges for use will be billed monthly based on the number of lamps installed.

TERMS OF CONTRACT

Two years and thereafter until canceled by one year's written notice.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "Terms and Conditions" for furnishing electric service.

BLOCK ISLAND POWER COMPANY
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FUEL ADJUSTMENT CLAUSE RIDER

RATE "FAC"

FUEL ADJUSTMENT CHARGE

The fuel adjustment charge will be calculated each month to cover the cost of financing fuel and urea inventories, transportation costs, as well as to cover the cost of fuel and urea usage in the following manner.

FUEL AND UREA FINANCING COST:

The beginning inventory value (fuel and urea) of the month being calculated will be multiplied times the prime rate (beginning of the month) plus 0.5% then divided by 12 (months) to arrive at the appropriate financing cost. This financing cost will then be divided by .96 to reflect the cost of gross receipt tax (GRT).

FUEL AND UREA USAGE EXPENSE:

The total number of gallons used of fuel for the month being calculated will be multiplied times the "weighted" cost of the fuel used and the related transportation cost (i.e. ferry, truck, driver, etc.) required for delivering the fuel to the Island. This calculated fuel cost will then be divided by .96 to provide for GRT.

The same calculation will be completed for the urea usage costs. The total number of gallons used of urea for the month being calculated will be multiplied times the "weighted" cost of the urea used and the related transportation cost required for delivering the urea to the Island. This calculated urea cost will then be divided by .96 to provide for GRT.

IRP AND DSM FUND:

There is a surcharge of 1.00¢ per kWh for Demand Side Management (DSM) and Intergrated Resource Planning (IRP) purposes for a period of 3 years from the effective date of this tariff. These funds shall be reserved for DSM and IRP purposes and accounted for separately by BIPCo. BIPCo shall have no obligation to perform any DSM or IRP programs for which funding is not available from this reserve. The funds shall be collected on kWh consumption in June, July, August and September of each year through the fuel surcharge (FAC). This calculated IRP and DSM fund will then be divided by .96 to provide for GRT.

FAC FACTOR:

The combined financing cost and usage costs for fuel and urea along with the IRP and DSM funding will then be divided by the kWh sales for the same month to arrive at a FAC factor to be applied to all kWh sales for that month.

APPROVAL:

The FAC factor will be submitted to the Division of Public Utilities and Carriers for review and approval before billing to the customers.

GENERAL TERMS AND CONDITIONS

This schedule is subject in all respects to the Company's "Terms and Conditions" for furnishing electric service.

BLOCK ISLAND POWER COMPANY

FUEL/UREA ADJUSTMENT WORKSHEET

		FUEL	IRP & DSM Funding	UREA
Calculation for the month of				
Financing Cost:				
Inventory quantity, beginning				
Value of beginning inventory	(a)			
Prime rate ___ plus .5%	(b)			
Financing Cost (a) x (b) /12				
Fuel Expense and Sales:				
Number of gallons used	(c)			
Weighted cost per gallon	(d)			
Fuel/Urea Expense (c) x (d) / .96	(e1)			
IRP & DSM Funding 1.00¢ x (h) / .96	(e2)			
Financing cost from above / .96	(f)			
Total Fuel and Urea cost (e) + (f)	(g)			
Sales for the month (kWh)	(h)			
Fuel, Urea & IRP/DSM adj. factor	(i)			

TOTAL FAC	

BLOCK ISLAND POWER COMPANY

TERMS AND CONDITIONS

The Block Island Power Company shall furnish electric service under its rate schedules and these Terms and Conditions as approved from time to time by the Public Utility Commission of the State of Rhode Island. These Terms and Conditions shall govern all electric service provided by the Block Island Power Company, except as specifically modified in rate schedules or written contracts. Copies of these Terms and Conditions and the Company's rate schedules are available at the Company's offices during normal business hours.

A. Definitions

When used in the Company's rate schedules and/or these Terms and Conditions, the following terms shall have the meanings as set forth below:

"**Company**" shall mean the Block Island Power Company.

"**Commission**" shall mean the Public Service Commission of the State of Rhode Island.

"**Applicant**" shall mean any person, partnership, association, corporation or other entity applying, on a prospective basis, for electric service from the Company or an electric service connection and to any present Customer who applies for a modification of existing electric service or facilities.

"**Application for Service**" shall mean the written form, provided by the Company and complete by a Customer or prospective Customer, requesting information relating to the Applicant's requirements for electric service, an electric service connection, and/or any modification in the electric service or facilities that the Company provides.

"**Billing Month**" shall mean the period between any two (2) regular readings of the Company's meters, at intervals of approximately thirty (30) days.

"**Customer**" shall mean any person, partnership, association, corporation or other entity lawfully receiving electric service from the Company or having a lawful electric service connection to the Company's electric distribution system. This definition shall apply separately to each metered facility and service connection.

"**Customer Equipment**" shall mean such wiring, equipment, apparatus, appurtenances, and electric energy consuming devices used or available for use on the Customer's premises.

"**Delivery Point**" shall mean the meter socket provided by the Company, which shall be installed by the Customer, or at the Customer's expense, at the location designated by the Company and shall be deemed to be the point at which electric service is provided to the Customer.

"**Demand**" shall mean the rate of use of electric energy as determined in accordance with the Customer's service classification or separate written contract and, as appropriate, measured by a fifteen-minute interval demand meter provided by the Company.

"**General Service Customer**" shall mean any Customer subject to billing under the terms of the Company's General Service Rate Schedules, either Rate "G" or Rate "D", as applicable.

"**kWh**" or "**kilowatt-hour**" shall mean the unit of measurement of electric energy use equal to the use of one thousand (1,000) watts for one hour.

"**KVA**" or "**kilovolt-ampere**" shall mean a unit of measurement of the rate of use of electric energy which determines the electric system capacity required.

"**Non-Residential Customer**" shall mean any Customer subject to billing under the terms of any of the Company's electric service rate schedules, other than the Company's Residential Service Rate Schedule, Rate "R".

"**Public Authority Customer**" shall mean a Customer subject to billing under the terms of the Company's Public Authority Service Rate Schedule, Rate "P".

"**Residential Customer**" shall mean a Customer subject to billing under the terms of the Company's Residential Service Rate Schedule, Rate "R".

"**Streetlighting Service Customer**" shall mean a Customer subject to billing under the terms of the Company's Streetlighting Service Rate Schedule, Rate "S".

"**Temporary Service Connection**" shall include electric service connections used for construction purposes, regardless of duration, and any service connection the duration of which, in the judgment of the Company, is not of a permanent nature. Electric Service through a Temporary Service Connection will be billed under the Company's General Service Rate Schedules, either Rate "G" or Rate "D" as applicable.

Throughout these Terms and Conditions references to the male gender shall be equally applicable to the female gender, as appropriate.

B. Application for Service

1. Application for Service must:

    a) be made in writing on the form provided by the Company for such Applications;

    b) be made for all new electric services, new electric service connections, and modifications in existing electric service requirements or facilities;

    c) be made by the owner of the premises or his duly authorized agent; and

d) contain the information necessary to determine the type of electric service desired and the conditions under which the service will be provided.

e) be delivered to the Company's business office, or mailed to:

Block Island Power Company
P. 0. Box 518
Block Island, Rhode Island 02807

2. If the Applicant is not the owner of the premises, the Company may, in its discretion, require the Applicant to:

a) provide satisfactory written evidence that he has authority to occupy and/or use the premises, and

b) establish credit-worthiness satisfactory to the Company. Credit-worthiness may be established through the making and maintaining of an appropriate Customer Deposit as set forth in these Terms and Conditions.

C. Availability of Service

The Block Island Power Company provides alternating current at 60 cycles through a radial system throughout the Company's service territory. Voltage, phase characteristics, and method of serving depend upon load and location. Applicants, Customers, and their agents or contractors should consult with the Company prior to purchasing equipment, making power installations or making changes to existing power installations.

1. Within a reasonable period of time after receipt of an Application for Service, the Company will furnish the Applicant such information with respect to the electric service as to the Delivery Point and the characteristics of the service which is or will be available at the Delivery Point. Thereafter, the Company shall require reasonable time to determine the Applicant's compliance with these Terms and Conditions and to assemble and install the required service facilities.

2. Special terms and rates for furnishing electric service may be established, subject to Commission approval, when the conditions of use or other circumstances render it inequitable to the Company and/or its other Customers for the Company to provide such service under an established rate schedule. Such conditions include, but are not limited to, abnormal load factor, power factor, size and fluctuations in demands. In such circumstances, the Company will require a written contract with special guarantees from Applicants whose unusual load or service characteristics would require excessive investment in facilities or whose requirements for service are of a special nature.

D. Company's Right to Modify or Reject Applications for Service

1. The Company reserves the right to reject any Application for Service made by, or for the benefit of, a former Customer who is indebted to the Company for electric service previously furnished to him, or for his benefit.

2. The Company may (a) refuse electric service to any Applicant, b) modify the terms of any Application for Service, or (c) terminate service to any Customer, whose customer-owned equipment or electric load, or service characteristics will, in the sole judgment of the Company, injuriously affect the operation of the Company's electric system or its service to other Customers.

E. Service Connections

The Company will furnish a meter or meters for each Customer and will, subject to compliance with these Terms and Conditions and applicable codes and regulations, connect its distribution lines with the Customer's service connection equipment. All Customer service connection equipment, including all wiring, equipment, meter board, fuse box or disconnect panel, service switch, and appurtenances shall be furnished by the Customer, at his expense, and shall be installed in accordance with the most recent edition of the National Electrical Code and maintained in an approved location, readily accessible at all times to employees of the Company.

Where high voltage service is provided, the Customer, at his expense and in a manner satisfactory to the Company, shall furnish, install, and maintain on his premises such switches, transformers, regulators, and other Customer Equipment as the Company may deem necessary to complete the service connection.

An Applicant, or Customer, may obtain an underground service connection from overhead wires only by installing, maintaining, and relocating, as required, the underground service connections at his own expense. All underground systems installed henceforth shall be a direct burial system with conduit, messenger, pad mount vaults, and hand holds every two hundred (200) feet. All underground wires will be laid on a base of no less than three (3) inches of sand and covered by no less than three (3) inches of sand. All work must be completed in compliance with applicable sections of the Rhode Island general laws.

In the event that the Company is required by any public authority to replace existing overhead distribution wires, equipment and/or services underground or to relocate any poles or feeders by which a Customer is served, the Customer shall change, at his own expense, the Point of Delivery to a new point, as designated by the Company.

F. Temporary Service Connection

The Company will not install a Temporary Service Connection attached directly to any mobile equipment. If Temporary Service is provided, the Customer shall pay the Company a Contribution-In-Aid-of-Construction, in an amount equal to the estimated cost of furnishing and installing the Company-supplied temporary connection facilities and the cost of removing and/or abandoning those temporary facilities, less the estimated salvage value of the materials returned to the Company at the end of the temporary service. The Contribution-in-Aid-of-Construction and any Customer deposit shall be paid, in full, prior to the commencement of activities to make the Temporary Service Connection.

G. Condition of Customer Equipment

All Customer Equipment, including all wiring, equipment, apparatus and appurtenances supplied, installed, or furnished by a Customer shall conform to the Company's requirements under these Terms and Conditions and shall at all times conform to the requirements and regulations of applicable national, state, and local codes. The Company may refuse to commence service or may terminate service if the condition of any Customer Equipment, on the premises to be served, or being served, are not installed and maintained in accordance with the standards required by any federal, state, or local governmental authority and these Terms and Conditions.

H. Company's Right to Inspect Customer Equipment

The Company reserves the right to inspect and approve the installation of all Customer Equipment on Customer premises served, or to be served, which uses or may use the Company's electric service. If wiring permits and/or inspection certificates are issued by local authorities, the Company will not supply service until such permits or certificates have been received by the Customer. The Company shall be under no obligation, however, to perform any inspection to ascertain compliance of any Customer Equipment with the national, state and local codes or these Terms and Conditions.

I. Company's Right to Enter Customer Premises

The Company, through its duly authorized and properly identified employees, has the right to enter the premises of a Customer at all reasonable hours for the following purposes:

1. Making such inspections of Customer Equipment as may be necessary for proper application of the Company's rates and these Terms and Conditions;

2. Installing, removing, testing, or replacing the Company's property, including meters, equipment, apparatus, and appurtenances as may be reasonably required to maintain the Company's property and the Customer's service;

3. Reading meter(s); and

4. In the event of a termination of service, removal of any and/or all Company property, including meters, equipment, apparatus and appurtenances.

J. Customer Deposits

1. **Residential Customers** - Customer Deposits from Residential Customers shall be assessed in accordance with the rules and regulations promulgated by the Rhode Island Division of Public Utilities and Carriers regarding Residential Customer Deposits. Therefore, the Company hereby incorporates, by reference, the terms of the rules and regulations promulgated by the Rhode Island Division of Public Utilities and Carriers regarding residential Customer Deposits as part of these Terms and Conditions with respect to its Residential Customers.

2. **Non-Residential Customers** - The Company reserves the right to require a Customer to make cash Customer Deposit with the Company of an amount not to exceed an amount equivalent to the aggregate of the Customer's two greatest bills for electric service during the prior calendar year. In the case of an Applicant, the Company shall use its best estimate of an amount equivalent to the two greatest bills which the Applicant may incur as a Customer over the next

succeeding twelve calendar months, using the load and service characteristics anticipated in that period. Thereafter, the Company may increase the required amount of any Customer Deposit once each calendar year to an amount not to exceed the aggregate of the Customer's two greatest monthly bills rendered within the most recent twelve month period.

3. Customer Deposits are obtained by the Company to assure payment of bills for service provided by the Company. Customer deposits only represent security for amounts due to the Company for electric service and other claims against the Customer and do not represent payment for services or of claims by the Company. The Company, in its sole discretion, may return to the Customer any amount held by it as a part of a Customer Deposit where the Customer has established satisfactory credit.

4. All Non-Residential Customer Deposits shall be deposited in an interest bearing account and interest earned from the date of deposit until return to the Customer or, upon the Termination of Service, the date credited against any amounts due and payable to the Company.

K. Rates for Electric Service

On the Application for Service, the Applicant shall identify the rate schedule under which the Applicant seeks to receive the requested service. The Company will review the Applicant's request, and render an initial determination regarding whether the Applicant qualifies for service under the rate requested. If the Company determines that the Applicant does not qualify for service under the rate schedule designated by the Applicant, the Applicant must request service under another rate schedule. The Company does not guarantee that any Customer will be served under the most favorable rate schedule available to the Customer. Furthermore, the Company does not assume responsibility, either at the time of the initial service application or at any subsequent point in time, for identification of the most favorable rate schedule for the Customer. The Company will not refund any difference between the charges assessed to a Customer under the rate schedule under which the Customer is billed and the charges the Customer would have been assessed under another rate schedule for which the Customer qualifies.

Copies of the Company's currently applicable rate schedules are available for inspection upon request at the Company's office.

L. Billing

Each Customer's meter will be read at regular intervals and bills will be rendered on a monthly basis or periodically in accordance with the terms of the applicable rate schedule. Bills will be rendered as soon as practical after determination of their amount and shall be due when presented or at such later date as may be indicated on the bill. Bills are payable at the Company's office or to any authorized collector or agency. Bills shall be deemed presented when 1) delivered to the Customer personally, 2) mailed to him at the premises where service is provided or the last known address of the customer, or 3) left at either of such places.

Bills, in general, will be based upon meter readings, but bills will be adjusted to compensate for errors in meter registration and meter reading and the application of rate schedules to intervals of greater or less than a month. In the event of a stoppage or failure of a meter to register, the Customer will be billed for such period on estimated consumption and demand, where applicable, based upon his use of electric energy and demand, where applicable, in a similar period of like use or on the basis of check meter readings, if available and accurate. Adjustments shall be limited to the Customer last served at that particular delivery point.

M. Late Payment Charge

Bills are due and payable on the date presented, or if a later due date is indicated on the bill, the date indicated on the bill. All payments received are applied first to the payment of late charges and then to payments for electric service. The date of payment is the date payment is received at the Company's offices or by any authorized collector or agency. If a bill is not paid within twenty (20) days after the billing date or the due date, as indicated on the bill, whichever is later, a late payment charge will be added to the bill. When the twenty (20) days for payment expire on a holiday, or on a Saturday or Sunday, the payment period is extended through the next business day.

The late charge is equal to one and one-half (1½) percent of the amount of the bill after the first non-payment period. If the amount due, including the late charge, is not paid within twenty days of the next billing date, an additional late charge equal to one and one-half (1½) percent of the original amount is charged after the second non-payment period. If the original amount remains unpaid twenty (20) days after the second billing date for the second succeeding month, an additional late charge of two (2) percent of the original bill will be assessed. This will result in imposition of the maximum aggregate late charges equal to five (5) percent of the original amount of the bill. Payments for electric service are applied first to the oldest outstanding charges.

N. Averaged Payment Plan

An Averaged Payment Plan is offered by the Company to assist residential customers in budgeting for, and payment of their monthly charges for electric utility service.

1. Upon the written request of a Residential Customer during the calendar months of October, November, or December of each year, an Averaged Payment Plan is available for budget billing of service provided under the Residential Rate Schedule, Rate "R". The Averaged Payment Plan is available only if all bills for past service have been paid at the time of the request.

2. The amount billed each month under the provisions of this optional payment plan, will be equal one-twelfth (1/12) of the total charges for service, as computed under the then applicable Residential Rate Schedule, for the twelve month period ended with the current billing month, rounded to the nearest dollar amount. The minimum monthly bill under this plan is fifty dollars ($50.00).

3. In the case of a new Customer, a Customer who has taken service for less than twelve (12) months, or where a significant change in the Customer's consumption is indicated, the Company will estimate the Customer's annual usage.

4. At the end of each twelve (12) month period (ended October, November or December), the twelfth monthly bill will be adjusted to reflect actual use during the twelve month period then ended. During each twelve (12) month period of the Averaged Payment Plan year, the Company will provide, with each monthly billing, a statement showing the actual charges incurred during

the current Averaged Payment Plan year and the aggregate of the amounts billed through that month. In no instance shall any deviation from the amounts billed on the Average Payment Plan absolve the Customer from paying the actual charges incurred during the twelve month period then ended.

5. During the period in which the Customer is participating in the Averaged Payment Plan, late payment charges apply to the late payment of amounts billed and due under the Plan, and not to the cumulative difference between the amounts and due under the Plan and amounts which would have been due but for participation in the Plan.

6. Upon the failure of a Customer to make any payment in a timely manner or, at any time, upon the written request of the Customer, the Customer will be removed from the Average Payment Plan and the excess of any actual charges incurred over amounts paid under the Averaged Payment Plan are immediately due and payable. If the amounts paid to date during the Averaged Payment Plan year exceed the actual charges incurred, the excess payments will be credited:

   a) First, against charges billed in the next month based upon actual amounts incurred during that month, and

   b) Second, against any other amounts due and payable to the Company. Any remaining excess will be remitted to the Customer with that next monthly bill.

O. Demand Metering

The Company may require the installation of a demand meter for any customer that qualifies for service under the Demand Metered General Service Rate Schedule, Rate "D", or the Public Authority Service Rate Schedule, Rate "P". The Company shall have the right to test a customer's use of service, and if any 15-minute interval metered demand for such customer is found to exceed eight (8.0) kilowatts such customer shall be transferred to an applicable demand metered service schedule. A residential customer for whom a metered 15-minute interval demand in excess of eight (8.0) kilowatts is recorded will be transferred to the Demand Metered General Service Rate Schedule, Rate "D".

Any demand metered customer whose monthly metered demands fail to exceed four (4.0) kilowatts for any month within a twenty-four (24) month period may, at the sole discretion of the Company, be transferred to another applicable service schedule.

P. Termination of Service

The Company reserves the right to terminate service to any Customer for any, or all of the following causes:

1. A dangerous condition exists, or is reasonably thought to exist, on the Customer's premises in any Company property and/or any Customer Equipment, including all wiring and energy-consuming devices;

2. Unauthorized or Fraudulent use of electric energy obtained from the Company;

3. Tampering with any Company equipment, including distribution lines, service lines, transformers, switches, protective devices, and meters;

4. The request of the Customer, upon not less than three (3) business days notice, except in the case of an emergency which includes a substantial threat to human life and/or of property damage, and subject to the terms of any existing agreement;

5. When Customer has previously been disconnected for non-payment and fails to pursue settlement of past service liabilities or fails to make payment of amounts due under a settlement of any past electric service liabilities;

6. Failure of an Applicant to make a Customer Deposit, or of a Customer to increase the amount of any Customer Deposit, to assure payment of bills for electric service, when properly requested by the Company;

7. Any violation of these Terms and Conditions, which the Customer refuses or fails to correct;

8. Non-payment of any bill from the Company for electric service; and/or

9. Failure of the Customer to permit Company personal access the Customer's premises for meter reading or for inspection of Company or Customer equipment or wiring as provided in Section H of these Terms and Conditions.

Q. Reconnection of Service

1. When electric service is terminated for any reason set forth in Section 9, there shall be a Reconnection Charge equal to the sum of:

   a) $25.00, if the Customer requests service be restored during the Company's normal working hours, or $50.00, if the Customer requests that service be restored at a time other than the Company's normal working hours; and

   b) the sum of the monthly Customer Charges for each month that service has been disconnected and no Customer Charge has been paid.

2. Further, the Company shall not be required to restore service terminated for any of the reasons set forth in Section O of these Terms and Conditions until:

   a) Dangerous conditions are removed, or reasonably demonstrated not to exist, within Company property and/or Customer Equipment, including all wiring and electric energy-consuming devices on the Customer's premises;

   b) All violations of these Terms and Conditions are corrected;

c) An arrangement, satisfactory to the Company, is made for the payment of all bills for service;

d) A Customer Deposit, in an amount satisfactory to the Company, is made to assure payment of bills for service; and

e) The Reconnection Charge is paid.

R. Line Extensions and Other Facilities

1. Whenever a line extension along a public highway or other facilities are required to supply electric service to an Applicant and the estimated expenditures of such line extension and/or other facility shall be of such amount that the revenue to be derived from that service at the applicable rates will, in the reasonable judgment of the Company, be insufficient to warrant such cost, the Company will require that the Applicant make an advance payment of a Contribution-In-Aid-of-Construction to cover the cost of such expenditures. The Contribution-In-Aid-of-Construction will include any and all costs associated with the completion of the line extension and other facilities required to serve the Applicant.

2. Whenever it is necessary, in order to provide electric service to an Applicant, to locate a pole or poles on private property or to pass over, under or through private property in order to complete a service connection on the Applicant's premises, any and all costs incident to the completion of such a service connection shall be paid to the Company by the Applicant as a Contribution-In-Aid-of-Construction. The Contribution-In-Aid-of-Construction required by the Company shall include any and all costs for:

   a) furnishing, erection, location, and/or modification of poles;

   b) equipment installed or used to effect the installation;

   c) the acquisition of right-of-way or easements; and

   d) any and all other costs associated with the installation of facilities to serve the Customer or Applicant.

3. A customer whose meter is to be more than one hundred fifty (150) feet from a public road will be charged a minimum charge of sixty cents ($.60) per foot for the distance from the meter location to the public road. The charge shall include the Customer's share of Contribution-in-Aid-of Construction for all customers served by the line. The distance of the line extension shall be measured under or over the line used.

4. All easements and right-of-ways must be satisfactory to the Company and, where obtained from the Customer or Customers to be served, the easement must run to the property line of the next abutting premises and be not less than twenty (20) feet in width.

S. Contributions-In-Aid-of-Construction

1. Amounts assessed as Contributions-In-Aid-of-Construction shall include the estimated income tax liabilities for the Company associated with the Company's receipt of the Contribution-In-Aid-of-Construction.

2. The Company will treat advance payments of construction costs as a Contributions-In-Aid-of-Construction for income tax and regulatory purposes and the Applicant or Customer shall have no additional rights or benefits as a result of such payments.

3. The entire amount of the Contribution-In-Aid-of-Construction shall be paid prior to the commencement of construction. Where more than one Customer is to be served by a line extension, the amount of the Contributions-in-Aid-of-Construction and any and all other costs of the line extension shall be apportioned ratably among the Customers to be served.

T. Customer Liabilities

All property of the Company installed in, or upon, Customer premises used or useful in supplying electric service is placed there under Customer's protection. All reasonable care shall be exercised to prevent loss of, or damage to, such property and, ordinary wear and tear excepted, the Customer will be held liable for any such loss of property or damage thereto and shall pay the Company the cost of necessary repairs or replacements.

Customer will be held responsible for breaking seals, tampering or interfering with Company's meter(s) and/or other Company equipment installed on Customer premises, and no one, except duly authorized and properly identified employees of the Company, will be allowed to make repairs or adjustments to any meter(s) or other Company equipment.

U. Company Liabilities

The Company shall not be liable for damages resulting in any way from the supplying or use of electric energy or from the presence or operation of the Company's service, conductors, appliances, meters, apparatus, appurtenances or other equipment on the Customer's premises.

The Company will exercise reasonable diligence in furnishing and maintaining a uniform, continuous and uninterrupted supply of electric energy as practicable within the provisions of its rate schedules. Should the supply of electric energy be interrupted, become faulty, or fail for any reason, the Company shall not be liable. The Company may interrupt service for the purposes of making necessary alterations, installations and repairs, promoting public safety and preventing excessive damage to property in the event of fire; lightning; high winds; snow; sleet; ice; high water; unavailability of fuel, spare parts or personnel; sabotage; malicious mischief; and without limiting the generality thereof, by reason of any other cause whatsoever. The Customer assumes all risk of loss or damage to person and property resulting or arising out of any such interruption, fault, or failure. Except in case of emergencies, the Company shall endeavor to give reasonable notice to Customers of interruptions.

In case the Company is obligated to discontinue the supply of electric energy to the Customer's premises as a result of the canceling of temporary permits for the extension of lines, or for other cause, the Customer shall have no claim against the Company on account of such discontinuance.