DIRECT TESTIMONY OF

RALPH SMITH, CPA

BEFORE THE

RHODE ISLAND PUBLIC UTILITIES COMMISSION

BLOCK ISLAND UTILITY DISTRICT

D/B/A BLOCK ISLAND POWER COMPANY

RATE CASE

DOCKET NO. 4975

ON BEHALF OF

THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

February 12, 2020

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I. INTRODUCTION

Q. What is your name, occupation, and business address?

A. My name is Ralph Smith. I am a Certified Public Accountant licensed in the State of Michigan and a senior regulatory consultant at the firm Larkin & Associates, PLLC, Certified Public Accountants, with offices at 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe the firm Larkin & Associates, PLLC.

A. Larkin & Associates, PLLC ("Larkin"), is a Certified Public Accounting and Regulatory Consulting Firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin has extensive experience in the utility regulatory field as expert witnesses in over 600 regulatory proceedings, including numerous electric, water and wastewater, gas and telephone utility cases.

Q. Mr. Smith, please summarize your educational background and recent work experience.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the C.P.A. examination on my first sitting in 1979, received my C.P.A. license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed Certified Public Accountant and attorney in the State of Michigan. Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association. I have also been a member of the American Bar Association (ABA), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. After graduating from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July 1979. Before becoming involved in utility regulation where the majority of my time for the past 40 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. Yes. I previously testified before the Rhode Island Public Utilities Commission for the Providence Water rate case, Docket No. 4618; the Suez Water rate case, Docket No. 4800; and the Narragansett Bay Commission rate case, Docket No. 4890.

Q. Have you previously submitted testimony before other state regulatory commissions?

A. Yes. I have previously submitted testimony before many other state regulatory commissions, including Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, Puerto Rico, Rhode Island, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia, and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law. My prior testimonies have included evaluations of numerous utility rate case filings and revenue requirement determinations.

Q. Have you prepared an exhibit describing your qualifications and experience?

A. Yes. I have attached Exhibit No. RCS-1, which is a summary of my regulatory experience and qualifications.

Q. On whose behalf are you appearing?

A. Larkin & Associates, PLLC, was retained by the Division of Public Utilities and Carriers ("the Division") to review the rate request of Block Island Utility District ("BIUD" or “Company”). Accordingly, I am appearing on behalf of the Division.

Q. What is the purpose of your testimony in this proceeding?

A. I am presenting the Division's overall recommended revenue requirement for BIUD in this case. I also address rate design for BIUD.

Q. Have you attached any other Exhibits or Schedules to your testimony?

A. Yes. I prepared Exhibit RCS-2 which presents the revenue requirement calculation for the rate year ending December 31, 2020, giving effect to all of the adjustments that I am recommending in this testimony. Exhibit RCS-2 contains schedules showing the revenue requirement, operating revenues, operating expenses, debt service and adjusted net operating income, and also includes schedules for each adjustment I am recommending.

Q. Are you presenting a separate rate design exhibit in this case?

A. No. Because the Division is treating this BIUD rate application as a revenue neutral filing as BIUD has proposed and the Division's review of the BIUD rate design reveals that it appears to be reasonable under the circumstances of this BIUD rate case, I am not presenting a proposed rate design for BIUD that differs from the rate design that has been proposed by BIUD in its application.

Q. How will your testimony be organized?

A. In Section II, I present the overall financial summary for the base rate change to be effective for the rate year ended December 31, 2020, showing the revenue requirement and revenue increase recommended by the Division.

In Section III, I discuss my proposed adjustments which impact the Company's revenue requirement. Exhibit RCS-2 attached to my testimony presents the Division's Revenue Requirement and Adjustment Schedules.

In Section IV, I discuss BIUD's proposed rate design and present the Division's recommendations. As noted above, for purposes of this case, the Division, after review, has found BIUD's proposed rate design to be reasonable and has therefore accepted the rate design proposed by BIUD in its application.

II. OVERALL FINANCIAL SUMMARY – BASE RATE CHANGE

Q. What overall revenue increase has the Company indicated that it is seeking?

A. The Company states that is not requesting any overall revenue increase in its filing. BIUD has presented its general rate case application in the current case as a revenue neutral filing, representing a revenue requirement increase of 0.00%, with total rate year revenues in the amount of $3,291,336.

Q. What revenue increase is the Division proposing for BIUD?

A. The Division is also proposing a revenue requirement increase of 0.00%, with total rate year revenues in the amount of $3,291,336 and is treating the current BIUD general rate case as a revenue neutral case. BIUD has proposed to make significant changes to its current rate design, but with no increase or decrease to BIUD's overall base rate revenues. The Division's presentation is similar.

III. REVENUE REQUIREMENT

Background

Q. When was BIUD's last rate case?

A. The current rate case is BIUD's first rate case. BIUD's predecessor, Block Island Power Company ("BIPCo") had a general rate case in Docket No. 3900 that BIPCo filed on November 9, 2007 and which resulted in Commission Order No. 19504 approving new rates for BIPCo effective June 1, 2008 to recover a cost of service of $2,607,548. At that point, BIPCo was structured as an investor-owned utility.

Q. How was BIPCo transformed from an investor-owned utility into BIUD, a non-profit utility district?

A. On March 25, 2019, BIUD purchased the assets of BIPCo for $5.8 million, including the business names "Block Island Power Company" and "BIPCo" and has been operating as Block Island's electric distribution provider. The current rate case is the first general rate case for BIPCo under the new BIUD ownership structure.

BIUD witness Bebyn provides the following summary of the transition from the old investor owned BIPCo to the new non-profit BIUD at page 4 of his Direct Testimony:

> Prior to November 2016, all the shares of BIPCo were held by three individual owners who each held one third of the outstanding shares of BIPCo. On November 7, 2016, the Town of New Shoreham purchased all the BIPCo shares from two of the owners. This provided the Town with a 2/3 majority ownership in BIPCo and resulted in a change in the BIPCo's Board of Directors. The new BIPCo Board moved towards transferring BIPCo into a utility district. On July 26, 2017, Senate Bill No. 729 Substitute A became effective without the Governor's signature. This new law (R.I.G.L. § 45-67-1 et seq.) created the BIUD. Under the Act, once the assets of BIPCo transferred to BIUD, BIPCo ceased functioning as an electric

utility. That transfer took place on March 25, 2019 when BIUD purchased all BIPCo's assets with an unsecured $5.8 million short-term loan from National Rural Utilities Cooperative Finance Corporation (CFC). This short-term loan from CFC was made permanent with a long-term note from CFC which was approved by the Division Docket #D-19-11.

Q. Did the change from an investor-owned utility to a non-profit utility district have a significant impact on BIUD's revenue requirement?

A. Yes. BIUD witness Wright's Direct Testimony at page 6 states that: "The ownership change from a for-profit utility to a not-for-profit utility had a material effect on revenue requirements, due to changes in tax obligations, finance costs and other major changes." Page 3 of BIUD witness Wright's Direct Testimony (and page 5 of BIUD witness Bebyn's Direct Testimony) lists the following items of savings that they indicate BIUD has realized since becoming a not-for-profit utility district:

1. Taxes	$269,973
2. Depreciation	$269,124
3. Income Taxes	$179,557
4. Dividends	$15,000
5. Sales Tax	$15,000
Total	$748,654

Q. Do you agree with BIUD that all of those items represent savings from becoming a not-for-profit utility?

A. Not entirely. I agree with BIUD that the avoidance of taxes, income taxes, dividends and sales tax represent savings associated with BIUD's status as a not-for-profit utility district. With respect to depreciation, while BIUD's proposed revenue requirement does not include depreciation expense, it does include costs for debt service, including interest and principal on the Cooperative Finance

Corporation (CFC) loans as well as capital funding account requests, so I view the including of principal and interest payments on loans plus the capital funding accounts as an alternative way of recognizing the revenue requirements associated with capital investment into the utility. Accordingly, I do not share BIUD's characterization of depreciation as an item of savings due to BIUD's status as a not-for-profit utility district when BIUD has included principal and interest and capital funding accounts in its requested revenue requirement.

Q. What has BIUD's President, Mr. Wright, stated concerning the terms of its primary financing related to the $5.8 million loan from its lender, CFC?

A. At page 4 of his Direct Testimony, Mr. Wright indicates that the terms of the $5.8 million loan have turned out to be favorable for BIUD:

> The original effective interest rate after discounts and patronage estimated by our lender CFC was 4.18%. Upon closing on the loan, the effective interest rate had dropped 100 bps to 3.18%. CFC also restructured the loan, terming out the entire $5.8M loan over 30 years rather than front loading the payments in years 1-7 as CFC originally proposed. This change levelized our debt service payments to approximately $300,000 per year for all 30 years compared to $540,000-$570,000 in years 1-7. This change will allow us to engineer and address the imminent voltage conversion sooner.

Q. What test year and rate year has BIUD used?

A. BIUD witness Bebyn indicates at page 6 of his Direct Testimony that BIUD used the test year ending December 31, 2018. BIUD is using a rate year ending December 31, 2020. BIUD witness Wright indicates at page 7 of his Direct Testimony that BIUD would like to have its newly designed rates go into effect on June 1, 2020 and filed its rate case accordingly.

<u>Minority Shareholder Litigation</u>

Q. At the time of BIUD's filing, was outstanding litigation pending with BIPCo's minority shareholder?

A. Mr. Wright indicates at pages 6-7 of his Direct Testimony that litigation involving BIPCo's minority shareholder is ongoing. While Mr. Wright indicates that BIPCo (now known as Island Light and Power Company) ended the litigation with its minority shareholder and while BIUD is no longer a party to that minority shareholder litigation, BIUD could have to pay up to $300,000 to the minority shareholder. Mr. Wright indicates that, if BIUD is required to pay any portion or all of that contingency amount, BIUD has a commitment from its lender to finance that debt over 30 years, and the debt service would be paid from BIUD's capital fund.

Q. Has that BIPCo minority shareholder litigation been resolved?

A. BIUD's response to DIV 1-25 provided some information on the status. As of the date of that response, the minority shareholder litigation had apparently not yet been resolved. BIUD's response to DIV 3-2 provided additional details and a status update. The minority shareholder litigation continues to be pending and has not yet been resolved.

Q. Did BIUD incur cost in 2018 and 2019 related to the BIPCo minority shareholder litigation?

A. Yes. As described in BIUD's response to DIV 3-2(a) and (b):

> a) ... BIUD did not book any legal costs to the 2018 Test Year because the Test Year is based on the BIPCo expenses from Calendar Year 2018. BIPCo did incur legal expenses in the calendar year 2018 related to the minority shareholder litigation that were not covered by D&O insurance. These costs were already removed as part of test year adjustments.
>
> b) Yes. The total paid by BIUD during calendar years 2018 and 2019, that was not covered by D&O insurance, was $25,484.69. $4,240.24 of the total paid was incurred in the calendar year 2019. These costs were charged to Account 923-012, but were not included in either the test or rate years.

Q. Have any costs related to the minority shareholder litigation been included by BIUD in rate year expenses and if so, how much and in what account?

A. No. As stated in response to DIV 3-2(b) and (c), BIUD did not include costs for the BIPCo minority shareholder litigation of $4,240 which BIUD recorded in 2019 in account 923-012.

Q. Did BIUD record any amount related to the $300,000 contingency? If so, when, how much, and in what account?

A. BIUD's response to DIV 3-2(d), which asked these questions, states: "No."

Q. Has a schedule for the minority shareholder litigation been established?

A. Yes . BIUD's response to DIV 3-2(e) indicates that a schedule for this litigation has been established in a December 2, 2019 conference. BIUD's response to DIV 3-29(f) provided the document containing that schedule. That schedule indicates that: "A pre-trial conference is scheduled for June 1, 2020." Thus, the trial in the BIPCo minority shareholder litigation apparently is scheduled to occur after the hearing in the BIUD rate case, which is currently scheduled for May 5-7, 2020.

Q. Do you have a recommendation regarding the BIPCo minority shareholder litigation?

A. Yes. BIUD should update the Commission on the status of that litigation at the hearings, and, if it not yet resolved at the time of the hearings, BIUD should updated the Commission in a letter as soon as it is resolved. BIUD's update should include pertinent information such as, how much, if any, of the $300,000 contingency it was required to pay and, conversely, avoided having to pay.

BIUD Proposed Rate Year Revenue Requirement

Q. What revenue requirement has BIUD proposed in this proceeding?

A. BIUD witness Bebyn indicates at page 5 of his Direct Testimony that BIUD estimates total rate year revenues of $3,291,336 and is not requesting any overall revenue increase in its filing.

Rate Year Revenues

Q. How did BIUD derive that amount of estimated rate year revenue?

A. BIUD's derivation of the rate year revenue at current rates of $3,291,336 is shown on BIUD Schedule DGB-RY-2 and is described in the Direct Testimony of BIUD witness Bebyn. Basically, BIUD started with $5,488,343 of 2018 test year revenue, removed the amount of $2,155,550 for pass through revenue, reflected a net reduction of $101,457 for adjustments from the test year to the rate year and added $60,000 for an energy efficiency grant, as summarized below:

Summary of Test Year and Rate Year Revenue		
Description	Amount	Note
TEST YEAR REVENUE:		
Pass Through Revenues	$ 2,155,550	Note A
Distribution charges	$ 2,217,971	
Demand Charges	$ 408,898	
Customer charges	$ 312,867	
System charges	$ 82,867	
Street Lighting	$ 6,985	
Other revenue	$ 303,204	
TOTAL TEST YEAR REVENUE	$ 5,488,342	Note B
Less Pass Through Revenues	$ (2,155,550)	Note A
TEST YEAR REVENUE EXCLUDING PASS THROUGH	$ 3,332,792	
Other BIUD Revenue Adjustments:		
Rate Year Adjustments	$ (101,457)	Note B
Efficiency Grant	$ 60,000	Note B
Rounding	$ 1	
ADJUSTED RATE YEAR REVENUE PER BIUD	$ 3,291,336	Note B
Notes and Source:		
BIUD Schedule DGB-RY-2		
Note A: Pass Through Revenues are removed		
Note B: Rate Year Adjustments and Efficiency Grant from BIUD Sch DBG-RY-2		

Q. Is BIUD's removal of the pass-through revenue for purposes of determining BIUD's revenue requirement in the current general rate case reasonable?

A. Yes. BIUD had filed its year-end report in Docket No. 4690 in March 2019 to set the rates for the Standard Offer, Transmission and Transition revenues effective May 1, 2019. These rates are scheduled to be re-set by a filing that BIUD will make in March, 2020. Because the rates for the pass-through revenue items are being reset in a separate process from BIUD's general rate case, the Division agrees with BIUD's removal of the test year revenue amount for those pass-through items.

Q. Please discuss BIUD's revenue adjustments to base rate revenue that reflect adjustments from the test year to the rate year.

A. As explained by Mr. Bebyn on pages 12-13 of his Direct Testimony, in response to customer complaints, BIUD has recommended the elimination of demand rates for residential customers. Additionally, Mr. La Capra has recommended other reclassifications such as elimination of Public Authority rate classes, which resulted in reclassifying the Public Authority customers into the Commercial and General Service rate classes, as explained on pages 12-13 of Mr. La Capra's Direct Testimony. Mr. Bebyn's Direct Testimony at page 13 describes those adjustments, with references to his schedules which contain additional details.

Q. What is the Division's position concerning BIUD's proposed elimination of demand rates for residential customers and the elimination of separate Public Authority rates and the related reclassification of Public Authority customers into Commercial and General Service rate classes?

A. The Division supports BIUD's proposed elimination of demand rates for residential customers and the elimination of separate Public Authority rates and the related reclassification of Public Authority customers into Commercial and General Service rate classes. Additional discussion of these issues is presented in the Rate Design section of my testimony.

<u>Other Revenue</u>

Q. Please discuss BIUD's proposed Rate Year amount for Other Revenues.

A. BIUD's adjusted test year amount for Other Revenue included the following items:

BIUD Adjusted Test Year and Rate Year Other Revenue				
Account	Description	BIUD Adjusted TY Amount	Rate Year Adjustment	Adjusted Rate Year Amount
419-000	Interest Income	$ 920		$ 920
421-002	Miscellaneous Income	$ 1,418		$ 1,418
421-004	Pole Accidents	$ 564		$ 564
421-007	Biller Penalty	$ 21,378		$ 21,378
421-012	Forgiveness on CAT Debt			$ -
421-013	(Gain) on Sale of Asset			$ -
421-014	Gain on Insurance Proceeds			$ -
451-002	Connection Charge	$ 925		$ 925
	Efficiency grant (new)		$ 60,000	$ 60,000
456-006	Rent - Lease	$ 260,000		$ 260,000
456-007	Rent -Office Apartment	$ 18,000		$ 18,000
Total Other Revenue		$ 303,205	$ 60,000	$ 363,205

As explained by BIUD witness Bebyn at page 13 of his Direct Testimony:

> All of these accounts were left at test year levels, except for the addition of a new account which provides a revenue grant from the state to cover half of the costs from the new energy efficiency program. Rental revenues (the largest of the other revenues) was already adjusted in the test year in this docket. The test year adjustment reflects a full year of rental income for each of the BIUD rental customers. There will be no change in tenants or the rent charged from the Test Year to the Rate Year.

With the inclusion of the energy efficiency grant, BIUD reflects Other Revenues increasing by $60,000 from the $303,204 adjusted test year amount to a rate year amount of $363,204.

Q. Has BIUD proposed higher reconnection fees?

A. Yes. The Direct Testimony of Mr. Wright at page 27, lines 20-21, proposes increases in Reconnection Fees of $25 to $40 during normal business hours and $50 to $75 outside of normal business hours.

Q. Would those higher reconnection fees result in higher rate year revenue if approved?

A. Yes, but not by a significant amount. BIUD's response to DIV 3-7 states that the adjusted test year amounts of $965 were based upon the current $25 and $50 rates, and higher reconnection fees would result in higher rate year revenue if approved but:

> ... we did not quantify the impact since this individual account is de minimis to the impact on overall revenues. Since the proposed reconnection rate is going up by about one-third, I estimate that the revenue increase will be less than $350 for a year.

Q. What cost support has BIUD provided for those Company-proposed increases?

A. BIUD's response to DIV 3-8 addressed the cost support and reasoning for the reconnection fee increases that BIUD is requesting. BIUD concludes that: "The small increase we are proposing is intended to make up for our increases in payroll expenses since 2008 when the fees were previously set."

Q. Has the Division accepted BIUD's proposed reconnection fee increases?

A. Yes. After reviewing the information provided by BIUD in response to Division discovery, those Company-proposed reconnection fees have been accepted.

Q. Is the Division making an adjustment to test year revenue for the higher reconnection fees?

A. No, due to the de minimus impact, as described in BIUD's response to DIV 3-7, no adjustment to test year revenues is being made for the reconnection fees. If the impact were significant, an adjustment would be made, but in this case, it is not.

Rate Year Expenses

Q. What level of rate year expenses does BIUD propose?

A. As shown on BIUD Schedule DGB-RY-3 and discussed in the Direct Testimony of BIUD witness Bebyn, BIUD proposes total rate year expenses of $3,291,336. That amount includes operating expenses as well as BIUD's requests for Debt Service and Capital Funds.

Q. Are you recommending any adjustments to BIUD's proposed level of rate year expenses?

A. Yes. Adjustments to BIUD's proposed level of rate year expenses are recommended for the following items:

- RI PUC Assessment
- Operating Reserve
- Interest and Principal on CFC Loan
- Voltage Conversion Capital Fund

RI PUC Assessment

Q. What amount did BIUD reflect for the Commission's assessment?

A. BIUD reflected an amount of $29,954 for the Commission assessment, and other costs in account 928-001, Regulatory Commission Expense, as described on page

19 of Mr. Bebyn's Direct Testimony. That was the test year amount which BIUD recorded in account 928-001, Reg Comm Exp. Mr. Bebyn stated (at p.19) that: "BIPCo expects that this charge will be about the same as the test year level for the rate year."

Q. What amount of RI PUC assessment to BIPCo did the Company reflect?

A. BIUD's response to DIV 1-24 shows an assessment amount of $24,012 on an invoice dated December 31, 2018, which was paid by BIUD on January 11, 2019.

Q. Has that subsequently been reduced?

A. Yes. The FY 2020 assessment was recently issued, and shows a RI PUC assessment to BIPCo of $20,734, which has been paid by BIUD.

Q. What amount do you recommend?

A. I recommend that the FY2020 assessment amount of $20,734 be used. The amount BIUD recorded in the 2018 test year of $24,012 in account 928-001 should be reduced to reflect a 2020 rate year amount of $20,734, based on the recently issued and paid FY2020 assessment. BIUD agrees with this adjustment, as stated in the Company's response to DIV 3-4. As shown on Schedule RCS-3, BIUD's proposed amount for the RI PUC assessment has been reduced by $3,278 to adjust from the $24,012 in BIUD's filing to the $20,734 amount in the FY2020 assessment.

<u>Operating Reserve</u>

Q. What has BIUD proposed for an Operating Reserve?

A. BIUD has proposed an Operating Reserve of $95,864 as shown on Company Schedule DGB-RY-3, page 4 of 5. BIUD used a 3.0% rate to calculate that.

Q. What rate is used by other utilities to compute the Operating Reserve?

A. As described in the Company's response to DIV 3-5, a 1.5% rate is used by the Pascoag Utility District and by Kent County Water Authority. Both of those utilities use 1.5% of expenses to calculate their Operating Reserve.

Q. Why does BIUD claim that it should have an Operating Reserve that is calculated using 3.0% of Operating Revenue excluding the Operating Reserve when those other utilities have an Operating Reserve that is based on a 1.5% rate?

A. BIUD's response to DIV 3-5 states that BIUD believes it has higher risk as an island utility than those two mainland utilities:

> When determining the operating reserve, BIUD considered other municipal utilities. The focus for these utilities was that they were stand alone from a city or town and therefore there was no city or town that could help mitigate risk. There are two regulated utilities that fit this criteria, Pascoag Utility District (PUD) and Kent County Water Authority (KCWA). Both of these utilities utilize 1.5% on total expense to calculate their reserve. When considering BIUD's reserve, I believe BIUD has more risk factors than PUD and KCWA. Those factors include (1) the risk of summer sales since BIUD's rates are heavily reliant on seasonal rates, and (2) the additional costs BIUD must bear because BIUD is isolated from the mainland. For example, additional costs resulting from being isolated from the mainland include increased transportation costs and temporary housing costs.

Q. Are there other costs incorporated into BIUD's revenue requirement which help mitigate its risk?

A. Yes. BIUD's revenue requirement includes capital funding amounts in addition to costs related to interest and principal on its debt. Thus, the Division does not support using a percent for BIUD's Operating Reserve that is double the one used by PUD and KCWA.

Q. What do you recommend?

A. I recommend that BIUD's Operating Reserve also be calculated using a rate of 1.5% similar to the rate being used for Pascoag. Other things being equal, the reduction from 3.0% to 1.5% would reduce BIUD's requested operating reserve of $95,864 by half or $47,932. After taking into account the reduction in the RI PUC assessment, multiplying adjusted Operating Revenue of $3,192,194 by the 1.5% produces an allowance of $47,883, which is $47,981 less than BIUD's proposed amount, as shown on Schedule RCS-4.

<u>Interest and Principal on CFC Loan</u>

Q. What has BIUD reflected for Interest and Principal on its CFC loan?

A. BIUD has reflected $184,455 for Interest and $113,064 for Principal paid on its CFC loan, for a total of $297,519.

Q. How does that compare with the amortization schedule that BIUD provided for its CFC loan?

A. It is lower than the annual payments of $315,035.48 that BIUD's response to DIV 3-14 provided in the amortization schedule for the CFC loan, which are summarized on Schedule RCS-5 for years 2020 through 2024.

Q. What do you recommend for Interest and Principal on BIUD's CFC loan?

A. As shown on Schedule RCS-5, I recommend using the 2020 Interest and Principal amounts for BIUD's CFC loan, which total $315,035, and are $17,517 higher than the $297,519 amount used by BIUD in its filing. BIUD's amortization schedule for the CFC loan shows Interest and Principal payments annually of $315,035 for 2020 as well as for each year in the remainder of the loan period. Using $315,035 would thus appear to more accurately reflect BIUD's ongoing annual obligations for payments under the CFC loan. As shown on Schedule RCS-5, this adjustment increases the net amount of Interest and Principal on the CFC loan by $17,517.

Q. Is it your understanding that BIUD has a revenue sharing arrangement with CFC such that the annual payments on the loan, after revenue sharing, could be lower than the $315,035 amounts that are listed in the loan amortization schedule?

A. Yes. I am advised that BIUD has a revenue sharing arrangement with CFC such that the annual payments on the loan, after revenue sharing, could be lower than the $315,035 amounts that are listed in the loan amortization schedule.

Q. Do you have a recommendation concerning how BIUD should account for payments of interest and principal that vary from the amounts that are being used to set BIUD's revenue requirement?

A. Yes. The Division's adjusted rate year amounts payments for BIUD interest and principal listed on Schedule RCS-1 for debt service are summarized below:

Debt Service Expenditures	Account	Amount Used
Interest on RUS Loan	427-001	
Interest on Engine 26 Loan	427-002	$ -
Interest - Other	427-003	$ 14,476
AIC Interest	427-004	$ -
Interest on CFC Loan		$ 209,908
Principal Paid on CFC Loan		$ 105,128
Totals		**$ 329,511**
Source: Schedule RCS-1, page 5, lines 153-158		

If BIUD's annual payments for interest and principal vary from the amounts listed on Schedule RCS-1 for debt service, as summarized in the above table, BIUD should record the differences into a Capital Fund account, so the differences can be tracked and applied on a pay-as-you-go basis to the funding of BIUD's capital projects.

<u>Voltage Conversion Capital Fund - Maintaining Revenue Neutrality</u>

Q. How much has BIUD requests for a Voltage Conversion Capital Fund?

A. BIUD has requested $62,441 for a Voltage Conversion Capital Fund.

Q. How did BIUD determine that amount?

A. Mr. Bebyn states that the funding level requested by BIUD for the voltage conversion capital fund "was set so BIUD would remain in a revenue neutral position in this case." As explained in the Company's response to DIV 3-18(c) this means that that BIUD's requested funding for the voltage conversion capital fund of $62,441 would be adjusted, either upward or downward, to the extent that other adjustments to BIUD's requested rate year revenue or expenses are proposed by the Division or are required by the Commission. BIUD explains that it hopes that the eventual funding of the voltage control project and the capital fund will minimize increases needed for future debt service to cover this capital project. BIUD's response to DIV 3-18(d) states that:

> The Voltage Conversion Project will be a capital budget item once we prepare an estimate, determine the funding mechanism and obtain BIUD BOD approval to proceed. We expect this project will be done over a 3-5 year period. The funding mechanism may require additional debt but at this point we are unsure.

Q. What difference in revenue requirement does the Division show prior to addressing BIUD's request for a Voltage Conversion Capital Fund?

A. The Division currently shows a revenue requirement that would otherwise be $33,743 less than requested by BIUD prior to addressing BIUD's request for a Voltage Conversion Capital Fund.

Q. How was that difference in revenue requirement addressed in the context of BIUD's proposed Voltage Conversion Capital Fund?

A. To keep the BIUD revenue requirement in this case revenue neutral, $33,743 was added to BIUD's request for a Voltage Conversion Capital Fund, as shown on Schedule RCS-6. The increase in the Voltage Conversion Capital Fund was made to essentially match BIUD's requested treatment. An alternative was considered by the Division to increase BIUD's Capital Fund.

Q. Please explain.

A. BIUD proposed $400,000 per year for two other Capital Funds:

- $93,000 for a Capital Fund-Inventory Purchased & Used, and
- $307,000 for a Capital Fund-Capitalized Expenditures

According to the Company's response to DIV 3-18(a) BIUD spent $631,692 on the list of capital projects provided with that response in FY 2019. That FY 2019 spending on capital projects compares with the Company's $400,000 budget for capital projects in FY 2019. Thus, in view of keeping with BIUD's proposal to keep its revenue requirement revenue neutral in the current case, an alternative was considered to increase BIUD's Capital Fund-Capitalized Expenditures by an equivalent amount, rather than the Voltage Conversion Capital Fund. Since both the Capital Fund-Capitalized Expenditures and the Voltage Conversion Capital Fund will be used to fund capital projects, the net impact on the revenue requirement of putting the adjustment to maintain revenue neutrality into one of those versus the other does not appear to matter. BIUD should be tracking its capital expenditures into the respective capital funding accounts.

Engine Maintenance Reserve Account Liability Balance

Q. Please discuss BIUD's Engine Maintenance Reserve account.

A. Under previous ownership of the electric utility, BIPCo had an Engine Maintenance Reserve Account. That account was transferred from BIPCO to BIUD when BIUD acquired the assets and liabilities of the electric utility. According to the trial balance that BIUD provided in response to DIV 3-5, BIUD account 254.004, SCR & Engine Maint Reserve, has a liability balance of $380,715 in March 2019, reflecting the transfer of BIPCo assets and liabilities to BIUD. A liability balance in such a reserve account indicates that BIPCo had spent less on engine maintenance that it had recorded/collected in rates for that reserve. The liability balance remaining in that BIPCo and now BIUD reserve account had not been fully utilized for its intended purpose of funding engine maintenance.

Q. How has BIUD applied that liability balance of $380,715 for the Engine Maintenance Reserve Account in its application?

A. It appears that BIUD has <u>not</u> applied that liability balance of $380,715 for the Engine Maintenance Reserve Account in its application. Discovery in DIV set 4 was recently issued to BIUD to confirm this and to obtain a Company proposal concerning how to apply that liability balance of $380,715 in the Engine Maintenance Reserve Account.

Q. How should the liability balance of $380,715 for the Engine Maintenance Reserve Account be applied?

A. The appropriate application in the current BIUD rate case of the $380,715 liability balance for the Engine Maintenance Reserve Account is under consideration by the Division. A discussion with BIUD's representative indicated that BIUD has $540,352 in account 342.001, Fuel Systems, which relates to a utility tank replacement project. Options for applying the liability balance of $380,715 for the Engine Maintenance Reserve Account could include refunding it to customers if it will not be needed for its originally intended purpose to fund engine maintenance, or applying it, similar to a contribution in aid to construction, against the cost of a similar capital project, such as the BIUD tank replacement project. The Division will review BIUD's response to DIV 4-1 and will present its recommendation for applying the $380,715 liability balance for the Engine Maintenance Reserve Account at a later stage of this proceeding.

IV. RATE DESIGN

General Rate Design Principles

Q. What general rate design principles has BIUD stated that it has applied?

A. Mr. La Capra's Direct Testimony at page 14 lists the following ten objectives as having guided BIUD's decisions on rate design:

> 1) Rates will adequately fund BIUD operations, capital expansion/replacement and efficient investments going forward;
>
> 2) Classes of service will be served under a single rate form;
>
> 3) Rate distinctions based on type ownership, e.g. public or private, will be eliminated;
>
> 4) Peak period usage will face a higher cost burden;
>
> 5) Off-peak usage will face a lower cost burden;
>
> 6) Peak period pricing will be confined to the two months when the peak actually occurs;
>
> 7) System charges are maintained for non-demand customers as a placeholder for excess (over base) usage which will be converted to a kWh charge with the new metering;
>
> 8) Customer charges are brought more into line with the cost of service results;
>
> 9) Demand customers kW charges will be based on the annual peak rather than a monthly peak, which now provides a low per kW charge in most months regardless of the peak burden the customer has placed on the system;
>
> 10) Energy efficiency surcharge will allow investment in new technologies to further improve the economies of electric usage on the island.

Q. Has the Division utilized those same principles?

A. Generally, yes. The Division has generally utilized similar guiding principles in reviewing BIUD's proposed rate design.

Revenue Requirement to Be Recovered in Base Rates

Q. What amount of base rate revenue requirement did BIUD use for its proposed rate design?

A. BIUD witness La Capra states at pages 2-3 of his Direct Testimony that the total rate year revenue requirement of $2,928,132 does not reflect an increase in the revenues produced by existing rates and forms the basis for BIUD's proposed rates. The $2,928,132 can be reconciled with BIUD's total rate year revenue requirement as follows:

Rate Year Revenue Requirement that BIUD Used for Base Rate Design		
Description	Amount	Notes
ADJUSTED RATE YEAR REVENUE PER BIUD	$ 3,291,336	Note A
Other revenue	$ (303,204)	Note A
Subtotal	$ 2,988,132	
Efficiency Grant	$ (60,000)	Note A
Revenue that BIUD Used for Base Rate Design	$ 2,928,132	Note B
Notes and Source		
Note A: BIUD Schedule DBG-RY-2		
Note B: Exhibit RLC___1, p.1 and Exhibit RLC___2, p.3, Total BIUD		

BIUD witness La Capra's Direct Testimony discusses the specific development of BIUD's cost of service study and proposed rate design to recover $2,928,132 in base rate revenue inclusive of approximately $60,089 for an energy efficiency surcharge. Mr. La Capra's Direct Testimony at pages 9-10 indicates that BIUD total revenues from base rates of $2,868,132 plus the approximately $60,000 for the

EE surcharge equal the $2,928,132 total amount of Current Rate Revenue amount that is listed in his Table 1 on page 8 of his Direct Testimony.

Energy Efficiency Surcharge

Q. What energy efficiency surcharge does BIUD propose?

A. Mr. La Capra's Direct Testimony at page 9 indicates that BIUD is proposing an EE surcharge as follows:

> The surcharge requested is $.00395/kWh for the months of May, June, September and October; and $.01/kWh for the months of July and August. Thus, the total BIUD revenue requirement is the sum of revenues from base rates ($2,868,132) and recovery of the proposed efficiency surcharge ($60,000) for the total of $2,928,132 shown in Table 1.

Mr. La Capra's Direct Testimony at pages 9-10 states that BIUD's energy efficiency surcharge would produce $60,089 in addition to base rate revenues, which he identifies in his Table 2 on page 10 as $2,868,059.[1] On average, using BIUD's proposed general service rates, the EE surcharge would add to the average bills for each rate class as follows:

- 2.0% to the average annual Residential bill;
- 1.8% to the average annual Commercial bill; and
- 2.2% to the average annual General Service bill.

Page 21 of Mr. La Capra's Direct Testimony indicates that BIUD has acquired a grant for $60,000 (half of the $120,000 earmarked for energy efficiency programs) and is proposing to add an energy efficiency surcharge to base rates to recover the remainder. He indicates that this EE surcharge did not increase the total rate revenues being sought by BIUD. Page 10 of Mr. La Capra's Direct Testimony

[1] Note: there is an $89 rounding difference between the $60,089 and the $60,000.

presents his Table 2 which shows estimated surcharge revenue by rate class, which totals to the $60,089 amount.

Q. In its application, did BIUD provide a specific energy efficiency ("EE") program that corresponds to its requested revenue amount for EE of $60,000?

A. No, not with BIUD's rate case filing. BIUD witness Wright states at pages 20-21 of his Direct Testimony that BIUD earmarked funding for the energy efficiency program in this rate case, subject to approval of the energy efficiency plan in a separate Commission docket. He indicates that BIUD is working with the Rhode Island Office of Energy Resources ("RI-OER") to develop the program. He states that the RI-OER expects to have the proposed program for BIUD by the end of 2019.

Q. Has BIUD provided additional details about its proposed EE program in response to Division discovery?

A. Yes. BIUD's response to DIV 3-1 provided additional details regarding the Company's proposed EE program, including Attachment JMW 3-1(b) to that response. BIUD stated in response to DIV 3-1(e) that it expects to spend the $60,000 budgeted amount in the 2020 rate year.

Q. Do you agree with BIUD's inclusion of $60,000 of rate year revenue requirement for an energy efficiency surcharge?

A. The Division has accepted BIUD's request for the $60,000 at this time and the related BIUD-proposed EE surcharge. As noted above, BIUD provided its EE plan including additional details for BIUD's EE program in response to DIV 3.1.

Major Rate Design Changes Proposed by BIUD

Q. What major rate design changes has BIUD proposed?

A. Mr. Wright's Direct Testimony at page 9-11 indicates that BIUD is proposing the following major changes to its rate design:

1. Eliminate Public Rate Classes.
2. Three-Tier Seasonal Rates instead of the current Two-Tier Seasonal Rates.
3. Eliminate the 8kW Residential Demand Rate Trigger.
4. Revise the Demand Rate for Large Users to set the Demand Charge based on the member's highest demand during the new peak period of July-August.

Eliminate Public Rate Classes

Q. What reasons has BIUD presented for eliminating the "Public" and "Public Demand" rate classes?

A. Mr. Wright states at page 9 of his Direct Testimony that the "Public" and "Public Demand" rate classes have very minor current rate differences from the General Service and Demand Service rates. He states that eliminating the "Public" rate classes will ensure fair treatment of consumers based on usage and would simplify BIUD's rate structure. Mr. La Capra provides the additional explanation at pages 12-13 of his Direct Testimony:

> Traditionally, the island has segregated commercial and general service applications into private and public categories and charged each differently. This was common throughout the industry with

> public rates, church rates, etc. These have largely disappeared as rate classes have come to be defined by costs and loads. Similarly, the BIUD proposes to consolidate like users into the same rate class; - either smaller commercial loads or larger demand-metered general service load. This proposal will eliminate the two public authority rate classes.

Q. Does the Division agree with BIUD's proposed elimination of the "Public" and "Public Demand" rate classes and BIUD's proposal to consolidate like users into the same Commercial or General Service rate classes?

A. Yes. The Division agrees with BIUD that the elimination of the "Public" rate classes would simplify BIUD's rate structure and provide for fair treatment of consumers through the use of Commercial and General Service rates.

<u>Three-Tier Seasonality Rate Design</u>

Q. Does BIUD's current rate design reflect two tiers, for seasonality?

A. Yes. BIUD's current rate design reflects two tiers for seasonal rates. As summarized by Mr. Wright on page 9 of his Direct Testimony, (1) off-peak rates apply for the months of October through May and (2) on-peak rates apply for the months of June through September.

Q. What three seasonal tiers does BIUD propose to use for its new rate design?

A. As summarized by Mr. Wright on page 9 of his Direct Testimony, BIUD proposes the following three seasonal periods for the tiers to be used in its proposed rate design: (1) off peak for the months of November through April; (2) "shoulder" periods of May-June and September-October; and (3) peak months of July and August. The rates BIUD has proposed are lower in the off-peak months, higher in the shoulder months and the highest during the peak months. Mr. La Capra's Direct Testimony addresses the proposed periods at pages 11-12.

Q. Why did BIUD determine that the peak months should be July and August?

A. Mr. La Capra explains at page 11 that the months of July and August have distinct load shapes and notes that BIUD's peak and the two highest annual peaks have occurred in those months.

Q. What objectives does BIUD indicate are served by having July and August designated as the peak months?

A. Mr. La Capra states (at page 11) that designating July and August as the peak months for purposes of BIUD's rate design, would provide a better relationship with cost causation and pricing efficiency since the peak-load (highest) pricing would be confined to those two months in which the peak load occurs.

Q. What objectives does BIUD indicate are served by its new three-tier seasonal rate design?

A. Mr. Wright states at page 10 of his Direct Testimony that its proposed seasonal rate design shift would encourage the use of efficient electric heating with the goal of reducing members' overall energy costs and addresses many of the goals that were outlined in Docket No. 4600.

Q. How would BIUD's three-tier seasonal rate structure impact customers?

A. Mr. La Capra's Exhibit RLC ___3, pages 2 through 4, present comparisons of monthly bills for Residential, Commercial and General Service customers, at BIUD's current and proposed rates, at average, high (1.25 times peak) and low (.75 times peak) usage. Notably, for Residential customers with higher than average usage, July bills are shown to be increasing by $37.48 per month, or 19.0% over current rates and August bills are shown to be increasing by $45.73 or 19.5% over current rates.

For each rate class (Residential, Commercial and General Service), the July and August peak-month bills would generally be higher under the new rate design than under current rate design. Bills for the months of June and September (which under the new three-tier design are shoulder months) are generally lower than under the current rate design; however, bills for the other shoulder months (May and October) are generally higher. Rates for the off-peak months (November through April) are generally lower under the new three-tier rate design than they would be under the current two-tiered rate design.

Mr. Wright recognizes at page 10 of his Direct Testimony that movement to a three-tier seasonal rate structure would be a big change for customers, and could create a significant price variation from period to period.

Q. How does BIUD propose to address customer concerns regarding the fact that three-tier seasonal rates could create a significant price variations from month to month?

A. At page 10 of his Direct Testimony, Mr. Wright indicates that BIUD would promote budget billing for its non-commercial customers. He indicates that BIUD's new billing system supports a budget billing feature. By selecting budget billing, a BIUD member who is not a commercial customer could smooth out their monthly utility billing amounts. He indicates that BIUD intends to aggressively promote budget billing to its members.

Q. Does the Division support BIUD's proposed three-tier seasonal rate design?

A. Yes. BIUD's analysis shows that peak usage has historically occurred in the months of July and August. Moreover, Mr. La Capra's analysis concludes that BIUD's electric consumption in July and August has a distinct load shape. Hence, refining the peak period to those months (versus the current peak period of June through September) is supported by the available information. Having peak pricing apply during an appropriately designated peak period relates to the objective of allocating costs among BIUD's customers based on when they use energy.

Designating shoulder periods (May-June and September-October) to provide a transition between off-peak and peak and designating the remaining months (November through April) as the off-peak period also appears to have merit and relate to the pattern in which electricity is consumed on BIUD's island system. Consequently, the Division generally supports BIUD's proposed three-tier seasonal rate design as being consistent with rate design objectives such as better alignment of costs and rates with usage periods. However, as recognized by BIUD's president, Mr. Write, to provide a means for Residential customers to avoid large monthly fluctuations in their electric bills, including the possibility of having much higher bills in the peak months of July and August, the Division recommends that

BIUD provide a budget billing option and to make sure that customers are aware of that option.

Eliminate the 8kW Residential Demand Trigger

Q. Approximately how many BIUD customers are impacted by the current 8kW Residential Demand trigger?

A. Mr. Wright states at pages 10-11 of his Direct Testimony that the current 8kW Residential demand trigger currently causes approximately 170 of BIUD's Residential customers to pay higher rates.

Q. Why does BIUD propose to eliminate the current 8kW Residential demand trigger?

A. Mr. Wright states that the 8kW demand trigger runs counter to BIUD's goal to empower customers to make decisions that could reduce their overall energy costs and reduce reliance on fossil fuels. Additionally, Mr. La Capra provides the following explanation at page 12 of his Direct Testimony:

> Currently, domestic users may be served on the residential rate or the general service rate, depending on their size and load patterns. While some cost justification argument could be made for this approach, it would be more efficient to properly price the residential rate in the peak period, thereby having residential customers who are larger or predominately peak load users pay their appropriate share. Additionally, this shifting around on two different rate schedules is a source of confusion and complaint among domestic customers and does not align these customers, as stakeholders, with company goals of equity and simplicity. i.e., understandability of the pricing.

Q. What would happen to the approximately 170 Residential Demand customers that had been affected by the 8kW demand trigger?

A. Mr. Wright indicates that BIUD would switch the approximately 170 customers from Demand to Residential, and BIUD's new three-tier seasonal rates would apply, which reflects lower winter rates, making electric heat more cost effective.

Q. Does the Division agree with BIUD's proposed elimination of the Residential 8kW demand trigger?

A. Yes.

<u>Revised Demand Rate Basing Period for Large Users</u>

Q. How does BIUD currently determine the Demand Rate for large users?

A. As explained by Mr. Wright on page 11 of his Direct Testimony, currently the demand rate is adjusted monthly based on usage during the billing month.

Q. What change does BIUD propose?

A. BIUD proposes to set the Demand Charge based on the member's highest demand during the new peak period of July and August.

Q. What reasons does BIUD provide for that change?

A. Mr. Wright states at page 11 of his Direct Testimony that this would provide more stable month-to-month costs for the member and would also provide revenue smoothing for BIUD. Mr. La Capra states at page 13 of his Direct Testimony that:

> The last structural change is in the way the demand charges will be collected. The peak period, as noted, is essentially the period which generates all long term marginal costs. Currently, the demand registered in the peak period is priced higher in that month but soon reduces as the peak pricing ends. As can be seen in how companies

> (and the BIUD) pay for their transmission and generation capacity use, the demands at the peak are driving the annual costs. As a result, the proposed demand rate will charge for the demand reached in the peak period as the demand for each of the following twelve months. This pricing approach, sometimes referred to as a ratcheting of demand, sets the monthly demand charge for the succeeding twelve months at the price of the demand rate times the demand at peak. This will align the pricing with the true marginal cost as well as encourage the efficient (increased) use of electricity in the off-peak months when there is no associated long term marginal cost. (footnote omitted.)

Q. Does the Division agree with BIUD's proposal to use the large user's highest demand during the new peak period of July and August to annually set the Demand Charge?

A. Yes. BIUD's peak occurs in July and August. The Division believes it is reasonable for BIUD to use the member's highest demand during that new peak period to annual set the Demand Charge.

Q. Does this complete your direct testimony?

A. Yes, it does.

Exhibit RCS-1

QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, Montana, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Oregon, Pennsylvania, Puerto Rico, South Carolina, South Dakota, Tennessee, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
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89-12-05	Southern New England Telephone Company (Connecticut PUC)
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92-09-19	Southern New England Telephone Company (Connecticut PUC)
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02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
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E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
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E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
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G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
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09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)

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E-01773A-09-0472	Arizona Electric Power Cooperative, Inc. (Arizona CC)
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10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
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09-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
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G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
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R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
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A.10-12-005	San Diego Gas & Electric Company (California PUC)
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G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
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Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
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Docket No. 13-0192	Ameren Illinois Company (Illinois CC)
12-1649-W-42T	West Virginia-American Water Company (West Virginia PSC)
E-04204A-12-0504	UNS Electric, Inc. (Arizona CC)
PUE-2013-00020	Virginia and Electric Power Company (Virginia SCC)
R-2013-2355276	Pennsylvania-American Water Company (Pennsylvania PUC)
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U-13-007	Chugach Electric Association, Inc. (The Regulatory Commission of Alaska)
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14-0117-EL-FAC	Financial, Management, and Performance Audit of the FAC and Purchased Power Rider for Dayton Power and Light – Audit 1 (Ohio PUC)
14-0702-E-42T	Monongahela Power Company and The Potomac Edison Company (West Virginia PSC)
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R-2014-2428743	Pennsylvania Electric Company (Pennsylvania PUC)
R-2014-2428744	Pennsylvania Power Company (Pennsylvania PUC)
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15-03-45^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
A.14-11-003	San Diego Gas & Electric Company (California PUC)
U-14-111	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)

2015-UN-049	Atmos Energy Corporation (Mississippi PSC)
15-0003-G-42T	Mountaineer Gas Company (West Virginia PSC)
PUE-2015-00027	Virginia Electric and Power Company (Commonwealth of Virginia SCC)
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15-0676-W-42T	West Virginia-American Water Company (West Virginia PSC)
15-07-38^^	Iberdrola, S.A. Et Al, and UIL Holdings Corporation merger (Connecticut PURA)
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15-042-EL-FAC	Management/Performance and Financial Audit of the FAC and Purchased Power Rider for Dayton Power and Light (Ohio PUC)
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U-15-089, U-15-091, & U-15-092	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
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PUE-2015-00097	Virginia-American Water Company (Commonwealth of Virginia SCC)
15-1854-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
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R-2016-2537352	Pennsylvania Electric Company (Pennsylvania PUC)
R-2016-2537355	Pennsylvania Power Company (Pennsylvania PUC)
R-2016-2537359	West Penn Power Company (Pennsylvania PUC)
16-0717-G-390P	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
15-1256-G-390P (Reopening)/16-0922-G-390P	Mountaineer Gas Company (West Virginia PSC)
16-0550-W-P	West Virginia-American Water Company (West Virginia PSC)
CEPR-AP-2015-0001	Puerto Rico Electric Power Authority (Puerto Rico Energy Commission)
E-01345A-16-0036	Arizona Public Service Company (Arizona CC)
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U-16-066	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Case No. 2016-00370	Kentucky Utilities Company (Kentucky PSC)
Case No. 2016-00371	Louisville Gas and Electric Company (Kentucky PSC)
P-2015-2508942	Metropolitan Edison Company (Pennsylvania PUC)
P-2015-2508936	Pennsylvania Electric Company (Pennsylvania PUC)
P-2015-2508931	Pennsylvania Power Company (Pennsylvania PUC)
P-2015-2508948	West Penn Power Company (Pennsylvania PUC)
E-04204A-15-0142*	UNS Electric, Inc. (Arizona CC)
E-01933A-15-0322*	Tucson Electric Power Company (Arizona CC)
UE-170033 & UG-170034*	Puget Sound Energy, Inc. (Washington UTC)
Case No. U-18239	Consumers Energy Company (Michigan PSC)
Case No. U-18248	DTE Electric Company (Michigan PSC)

Case No. 9449	Merger of AltaGas Ltd. and WGL Holdings (Maryland PSC)
Formal Case No. 1142	Merger of AltaGas Ltd. and WGL Holdings (District of Columbia PSC)
Case No. 2017-00179	Kentucky Power Company (Kentucky PSC)
Docket No. 29849	Georgia Power Plant Vogtle Units 3 and 4, VCM 17 (Georgia PSC)
Docket No. 2017-AD-112	Mississippi Power Company (Mississippi PSC)
Docket No. D2017.9.79	Montana-Dakota Utilities Co. (Montana PSC)
SW-01428A-17-0058 et al	Liberty Utilities (Litchfield Park Water & Sewer) Corp. (Arizona CC)
U-18-021 & U-18-033	Chugach Electric Association, Inc. (Regulatory Commission of Alaska)
Docket No. 4800	Suez Water Rhode Island Inc. (Rhode Island PUC)
General Order No. 236.1	In the Matter of the Effects on Utilities of the 2017 Tax Cuts and Jobs Act (West Virginia PSC)
20180047-EI	Duke Energy Florida, LLC. (Florida PSC)
20180046-EI	Florida Power & Light Company (Florida PSC)
20180048-EI	Florida Public Utilities Company – Electric (Florida PSC)
20180052-GU	Florida Public Utilities Company – Indiantown (Florida PSC)
20180054-GU	Florida Division of Chesapeake Utilities Corporation (Florida PSC)
20180051-GU	Florida Public Utilities Company – Gas Division (Florida PSC)
20180053-GU	Florida Public Utilities Company - Fort Meade (Florida PSC)
Cause No. 45032 S4	Indiana American Water Company, Inc. Phase 2 (Indiana Utility Regulatory Commission)
Docket No. D2018.1.6	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. D2018.4.24	NorthWestern Energy (Montana PSC)
Docket No. D2018.4.22	Montana-Dakota Utilities Co. (Montana PSC)
18-0573-W-42T & 18-0576-S-42T	West Virginia-American Water Company (West Virginia PSC)
18-0646-E-42T & 18-0645 E-D	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
18-0049-GA-ALT, 18-0298-GA-AIR, & 18-0299-GA-ALT	Vectren Energy Delivery of Ohio, Inc. (Ohio PUC)
R-2018-3003558, R-2018-3003561	Aqua Pennsylvania, Inc. and Aqua Pennsylvania Wastewater, Inc. (Pennsylvania PUC)
Cause No. 45142	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
U-18-043	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
T-03214-17-0305	Citizens Telecommunications Company of The White Mountains, Inc. d/b/a Frontier Communications of The White Mountains (Arizona CC)
Docket No. D2018.9.60	Montana-Dakota Utilities Co. (Montana PSC)
Docket No. 4890	Narragansett Bay Commission (Rhode Island PUC)
PUR-2018-00131	Columbia Gas of Virginia (Virginia SCC)
EL18-152-000	Louisiana PSC v. System Energy Resources, Inc. and Entergy Services, Inc. (FERC)
PUR-2018-00175	Virginia-American Water Company (Virginia SCC)
A-2018-3006061, A-2018-3006062 and A-2018-3006063	Aqua America, Inc., Aqua Pennsylvania, Inc., Aqua Pennsylvania Wastewater, Inc., Peoples Natural Gas Company LLC, Peoples Gas Company LLC (Pennsylvania PUC)
Docket No. 42310	Georgia Power Company – Integrated Resource Plan (Georgia PSC)
U-18-102	Municipality of Anchorage d/b/a Municipal Light & Power Department (Regulatory Commission of Alaska)
PUC Docket No. 49494	AEP Texas, Inc. (Texas PUC)

Application 18-12-009	Pacific Gas and Electric Company (California PUC)
19-0316-G-42T	Mountaineer Gas Company (West Virginia PSC)
19-0051-EL-RDR	Management/Performance and Financial Audit of the Alternative Energy Recovery Rider of Duke Energy Ohio, Inc. (Ohio PUC)
ER-18-1182-001	System Energy Resources, Inc. (FERC)

* Testimony filed, examination not completed
** Issues stipulated
*** Company withdrew case
^ Testimony filed, case withdrawn after proposed decision issued
^^ Issues stipulated before testimony was filed

Block Island Utility District
Docket No. 4975
Revenue Requirement and Adjustment Schedules
Accompanying the Direct Testimony of Ralph Smith

CONTENTS

Block Island Utility District

Summary of Revenues and Expenses at Present and Proposed Rates
Rate Year Ended December 31, 2020

Docket No. 4975
Schedule RCS-1
Page 1 of 5

Line No.	Description	Account No.	Rate Year Amount Per BIUD (A)	Division Adjustments (B)	Rate year at Present Rates (C) = A + B	Proposed Rate Increase (D)	Rate Year at Proposed Rates (E) = (C) + (D)
	Operating Revenue - Rate Revenue						
1	Residential-Plant/Distribution Charge	440-001	$ 918,843		$ 918,843		$ 918,843
2	Commercial-Plant/Distribution Charge	442-101	272,955		272,955		$ 272,955
3	Demand Customers-Plant/Distribution Charge	442-201	1,045,713		1,045,713		$ 1,045,713
4	Public Authority-Plant/Distribution Charge	444-001	(0)		(0)		$ (0)
5	Street Lighting	445-000	6,985		6,985		$ 6,985
6	Customer Charge- All Rate Classes	456-001	303,285		303,285		$ 303,285
7	Demand - All Rate Classes	456-002	285,868		285,868		$ 285,868
8	System Charge- All Rate Classes	456-004	94,482		94,482		$ 94,482
9	Total Operating Revenue---Electricity Charges by Customer Class		$ 2,928,131	$ -	$ 2,928,131	$ -	$ 2,928,131
	Other Revenue						
10	Interest Income	419-000	$ 920		$ 920		$ 920
11	Miscellaneous Income	421-002	1,418		1,418		$ 1,418
12	Pole Accidents	421-004	564		564		$ 564
13	Biller Penalty	421-007	21,378		21,378		$ 21,378
14	Forgiveness on CAT Debt	421-012	(0)		(0)		$ (0)
15	(Gain) on Sale of Asset	421-013	(0)		(0)		$ (0)
16	Gain on Insurance Proceeds	421-014	0		0		$ 0
17	Connection Charge	451-002	925		925		$ 925
18	Efficiency grant		60,000		60,000		$ 60,000
19	Rent - Lease	456-006	260,000		260,000		$ 260,000
20	Rent -Office Apartment	456-007	18,000		18,000		$ 18,000
21	Total Other Revenue		$ 363,204	$ -	$ 363,204	$ -	$ 363,204
22	Total Revenue		$ 3,291,336	$ -	$ 3,291,336	$ 0	$ 3,291,336
23	Total Expenses, Debt Service and Capital Funds		$ 3,291,336	$ -	$ 3,291,336	$ -	$ 3,291,336
24	Revenue Surplus/(Deficiency)		(0)	-	(0)	0	-
25	Company Proposed Increase		$ -		$ -		
26	Division Adjustment to Company's Request				$ (0)		

Notes and Source:
Column A: Company Schedule DGB-RY-2
Column B: Schedule RCS-2
Line 23: Schedule RCS-2, pages 2 through 5

Block Island Utility District

Summary of Revenues and Expenses at Present and Proposed Rates
Rate Year Ended December 31, 2020

Line No.	Description	Account No.	Rate Year Amount Per BIUD (A)	Division Adjustments (B)	Rate year at Present Rates (C)	Proposed Rate Increase (D)	Rate Year at Proposed Rates (E)
	Operating Expense---Power Production						
27	Supervision P/R Only	546-100	$ -		$ -		$ -
28	Fuel Procurement P/R Only	548-101	-		-		-
29	Watchman P/R Only	549-101	-		-		-
30	Inside Maint. P/R Only	549-103	107,119		107,119		107,119
31	Maint Station Equip. P/R Only	549-108	96,380		96,380		96,380
32	Freight	549-102	3,190		3,190		3,190
33	Lubrication	548-103	10,000		10,000		10,000
34	Miscellaneous	549-109	406		406		406
35	Uniforms	549-111	6,074		6,074		6,074
36	Purchased Power	555-100	-		-		-
37	Total Operating Expense---Power Production		$ 223,170	$ -	$ 223,170	$ -	$ 223,170
	Operating Expense---Distribution						
38	Supervision - P/R Only	580-100	$ -		$ -		$ -
39	Overhead Lines - P/R Only	583-101	206,981		206,981		206,981
40	Overhead Lines	583-102	11,415		11,415		11,415
41	Underground Lines	584-102	-		-		-
42	Meters - P/R Only	586-101	6,522		6,522		6,522
43	Meters-Maintenance	586-102	8,210		8,210		8,210
44	Meters-Data Services	586-103	24,658		24,658		24,658
45	Customers Install P/R Only	587-100	-		-		-
46	St Lights & Sign P/R Only	588-101	-		-		-
47	Misc Distrib. P/R Only	588-102	-		-		-
48	Misc Distrib. Expense	588-103	43,060		43,060		43,060
49	Lease - Motor Vehicle	589-100	41,426		41,426		41,426
50	Total Operating Expense---Distribution		$ 342,271	$ -	$ 342,271	$ -	$ 342,271
50	**Operating Expense---Customer Service**						
51	Meter Reading - P/R Only	902-000	$ -		$ -		$ -
52	Rec & Collection - P/R Only	903-000	54,653		54,653		54,653
53	Education and Training	916-001	12,101		12,101		12,101
54	Total Operating Expense---Customer Service		$ 66,754	$ -	$ 66,754	$ -	$ 66,754

Block Island Utility District

Summary of Revenues and Expenses at Present and Proposed Rates
Rate Year Ended December 31, 2020

Line No.	Description	Account No.	Rate Year Amount Per BIUD (A)	Division Adjustments (B)	Rate year at Present Rates (C)	Proposed Rate Increase (D)	Rate Year at Proposed Rates (E)
	Operating Expense---Administrative						
55	Office Salaries - P/R Only	920-001	$ 14,678		$ 14,678		$ 14,678
56	Accrued Vacation	920-003	5,610		5,610		5,610
57	Vacation Pay - P/R Only	920-004	-		-		-
58	Holiday Pay - P/R only	920-005	-		-		-
59	Holiday Not Worked - P/R Only	920-006	-		-		-
60	Sick Leave Pay - P/R Only	920-007	-		-		-
61	Personal Pay - P/R Only	920-008	-		-		-
62	President's Compensation	920-009	157,597		157,597		157,597
63	CFO Compensation	920-010	-		-		-
64	COO Compensation	920-011	-		-		-
65	Admin & Management - PR Only	920-012	-		-		-
66	Bonus - P/R Only	926-004	-		-		-
67	Office supplies and Expense	921-001	36,449		36,449		36,449
68	Directors Meetings	921-002	-		-		-
69	Trash Removal	921-004	5,785		5,785		5,785
70	Plant Expense	921-005	12,771		12,771		12,771
71	Utilities Expense	921-006	13,008		13,008		13,008
72	Telephone Expense	921-007	30,240		30,240		30,240
73	O/S-Outside Services	923-000	7,239		7,239		7,239
74	O/S-Payroll Processing	923-005	4,583		4,583		4,583
75	O/S-General Regulatory Accounting	923-006	26,430		26,430		26,430
76	O/S-General Regulatory Legal	923-013	33,986		33,986		33,986
77	Legal & Accounting Rate Case	923-009	0		0		0
78	O/S-Legal-General	923-012	35,500		35,500		35,500
79	Accounting	923-019	37,027		37,027		37,027
80	Accounting-Audit	923-020	30,580		30,580		30,580
81	Accounting-Bookkeeping	923-022	30,281		30,281		30,281
82	Accounting-Taxes	923-024	-		-		-
83	Board Clerk	923-025	7,200		7,200		7,200
84	General Liability Ins	924-000	185,000		185,000		185,000
85	Employee Pension	926-001	91,500		91,500		91,500
86	Travel And Misc. Expense	926-002	5,345		5,345		5,345
87	Employee Benefits	926-003	94,971		94,971		94,971
88	Wellness Program	926-005	-		-		-
89	Benefits-coshare	926-006	(16,822)		(16,822)		(16,822)
90	Health Ins-Deductible Payable	926-007	3,913		3,913		3,913
91	Reg Comm Exp	928-001	29,954	(3,278)	26,676		26,676
92	Rate Case Expense	928-002	50,000		50,000		50,000
93	Employer 401k contribution	930-020	23,220		23,220		23,220
94	Bad Debt	930-021	(0)		(0)		(0)
95	Management Fee Bonus	930-023	-		-		-
96	Environmental	930-025	53,824		53,824		53,824
97	Web Design	930-029	0		0		0
98	Software & Billing Service	931-000	57,820		57,820		57,820
99	Total Operating Expense---Administrative		$ 1,067,687	$ (3,278)	$ 1,064,409	$ -	$ 1,064,409

Block Island Utility District

Summary of Revenues and Expenses at Present and Proposed Rates
Rate Year Ended December 31, 2020

Line No.	Description	Account No.	Rate Year Amount Per BIUD (A)	Division Adjustments (B)	Rate year at Present Rates (C)	Proposed Rate Increase (D)	Rate Year at Proposed Rates (E)
	Maintenance Expense---Power Production						
100	Supervision - P/R Only	551-201	$ -		$ -		$ -
101	Maintenance Of Struct P/R Only	553-203	-		-		-
102	Maint. Of Gen & Elect Plt	551-202	8,568		8,568		8,568
103	Small Tools	553-201	6,383		6,383		6,383
104	Tank Testing & Fuel Maint	553-202	25,000		25,000		25,000
105	Maint. Of Structures	553-204	4,718		4,718		4,718
106	Maint General Plant	553-206	9,762		9,762		9,762
107	Tank Replacement	553-207	0		0		0
108	General Maintenance	553-209	6,464		6,464		6,464
109	SCR Maint	549-113	-		-		-
110	SCR & Engine Maint Res.Exp.	549-114	90,000		90,000		90,000
111	Major Engine Maintenance	553-200	2,405		2,405		2,405
112	General Engine Maintenance	553-213	5,856		5,856		5,856
113	Engine Testing	553-219	-		-		-
114	Engine Rental (Non FAC)	553-220	-		-		-
115	Haz. Waste Store/Remove/Hd	553-221	5,210		5,210		5,210
116	Cellular Tower Maint & Expense	553-222	9,328		9,328		9,328
117	Misc.	554-203	1,006		1,006		1,006
118	Total Maintenance Expense---Power Production		$ 174,700	$ -	$ 174,700	$ -	$ 174,700
	Maintenance Expense---Distribution System						
119	Supervision - P/R Only	590-200	$ -		$ -		$ -
120	Overhead Lines - P/R Only	593-202	130,083		130,083		130,083
121	Fire Damage Repairs-PR	593-205	-		-		-
122	Storm Damage Repairs-PR	593-207	-		-		-
123	Underground - P/R Only	595-202	-		-		-
124	Meters - P/R Only	598-201	-		-		-
125	Station Equip	592-200	-		-		-
126	Truck Repair	549-104	26,546		26,546		26,546
127	Supplies	549-105	20,663		20,663		20,663
128	Tree Trimming	593-203	120,000		120,000		120,000
129	Fire Damage Repairs	593-204	(0)		(0)		(0)
130	Storm Damage Repairs	593-206	55,978		55,978		55,978
131	Transformer Expense	595-201	-		-		-
132	Maint Of Street Lights	596-202	-		-		-
133	Misc	596-203	-		-		-
134	Gasoline	554-201	10,125		10,125		10,125
135	Backhoe/Tractor Repair	598-202	-		-		-
136	Total Maintenance Expense---Distribution System		$ 363,395	$ -	$ 363,395	$ -	$ 363,395

Block Island Utility District

Docket No. 4975
Schedule RCS-1

Summary of Revenues and Expenses at Present and Proposed Rates
Rate Year Ended December 31, 2020

Line No.	Description	Account No.	Rate Year Amount Per BIUD (A)	Division Adjustments (B)	Rate year at Present Rates (C)	Proposed Rate Increase (D)	Rate Year at Proposed Rates (E)
	Taxes						
137	Property Taxes	408-010	$ 0		$ 0		$ 0
138	Payroll Taxes	408-030	59,543		59,543		59,543
139	RI Sales Tax	408-050	(0)		(0)		(0)
140	RI Gross Earnings Tax	408-061	(0)		(0)		(0)
141	Registrations	408-071	841		841		841
142	Federal Income Tax	409-010	(0)		(0)		(0)
143	Net Change In Deferred Tx	410-010	-		-		-
144	Total Taxes		$ 60,383	$ -	$ 60,383	$ -	$ 60,383
	Depreciation						
145	Depreciation		$ -		$ -		$ -
146	Total Depreciation		$ -	$ -	$ -	$ -	$ -
	Other Deductions						
147	Advertising	426-052	$ 274		$ 274		$ 274
148	Misc other expenses	426-054	112		112		112
149	Bank Service Fees	426-056	2,142		2,142		2,142
150	Finance Charges	426-057	147		147		147
151	Efficiency Program		120,000		120,000		120,000
152	Total Other Deductions		$ 122,676	$ -	$ 122,676	$ -	$ 122,676
	Debt Service and Capital Expenditures						
153	Interest on RUS Loan	427-001	$ (0)		$ (0)		$ (0)
154	Interest on Engine 26 Loan	427-002	-		-		-
155	Interest - Other	427-003	14,476		14,476		14,476
156	AIC Interest	427-004	-		-		-
157	Interest on CFC Loan		184,455	25,453	209,908		209,908
158	Principal Paid on CFC Loan		113,064	(7,936)	105,128		105,128
159	Capitalized Labor		-		-		-
160	Net Operating Reserve		95,864	(47,981)	47,883		47,883
161	Voltage Conversion Capital Fund		62,441	33,743	96,184		96,184
162	Capital Fund-Inventory Purchased & Used		93,000		93,000		93,000
163	Capital Fund-Capitalized Expenditures		307,000		307,000		307,000
164	Total Debt Service and Capital Expenditures		$ 870,300	$ 3,278	$ 873,578	$ -	$ 873,578
165	Total Expenses		$ 3,291,336	$ -	$ 3,291,336	$ -	$ 3,291,336

Notes and Source:
Column A: Company Schedule DGB-RY-3
Column B: Schedule RCS-2

Block Island Utility District
Summary of Adjustments

Rate Year Ended December 31, 2020

Line No.	Description	Division Adjustments	RI PUC Assessment RCS-3	Operating Reserve RCS-4	Interest and Principal on CFC Loan RCS-5	Voltage Conversion Capital Fund RCS-6
	Revenue					
1	Operating Revenue - Rate Revenue	$ -				
2	Other Revenue	-				
3	Total Revenue	$ -	$ -	$ -	$ -	$ -
	Expenses					
	Operations and Maintenance Expense					
4	Operating Expense---Power Production	$ -				
5	Operating Expense---Distribution	-				
6	Operating Expense---Customer Service	-				
7	Operating Expense---Administrative	(3,278)	(3,278)			
8	Maintenance Expense---Power Production	-				
9	Maintenance Expense---Distribution System	-				
10	Total Operations and Maintenance Expense	$ (3,278)	$ (3,278)	$ -	$ -	$ -
11						
12	Taxes	$ -				
13	Depreciation	$ -				
14	Other Deductions	$ -				
	Debt Service and Capital Expenditures					
15	Debt Service and Capital Expenditures	$ 17,517			$ 17,517	
16	Net Operating Reserve	(47,981)		(47,981)		
17	Voltage Conversion Capital Fund	33,743				33,743
18	Capital Fund-Inventory Purchased & Used	-				
19	Capital Fund-Capitalized Expenditures	-				
20	Total Debt Service and Capital Expenditures	$ 3,278	$ -	$ (47,981)	$ 17,517	$ 33,743
21	Total Expenses	$ -	$ (3,278)	$ (47,981)	$ 17,517	$ 33,743
22	Net Operating Income	$ -	$ 3,278	$ 47,981	$ (17,517)	$ (33,743)

Block Island Utility District
RI PUC Assessment

Rate Year Ended December 31, 2020

Docket No. 4975
Schedule RCS-3

Line No.	Description	Company Adjusted (A)	Division Adjusted (B)	Division Adjustment (C) = (B) - (A)
1	Adjustment to RI PUC Assessment	$ 24,012	$ 20,734	$ (3,278)

Notes and Source
Company responses to Division 1-24 and 3-4

Line No.	Description	Company Adjusted (A)		Division Adjusted (B)		Division Adjustment (C) = (B) - (A)
1	Total Revenue or Expense before Operating Reserve	$ 3,195,472	[1]	$ 3,195,472	[1]	
2	Division Adjustment to Operating Expenses			$ (3,278)	[2]	
3	Total Revenue Before Operating Reserve	$ 3,195,472				
4	Division Adjusted Revenue before Operating Reserve			$ 3,192,194		
5	Percent	3.0%		1.5%		
6	Adjustment to Operating Reserve	$ 95,864		$ 47,883		$ (47,981)

Notes and Source

Col. A: Company Schedule DGB-RY-3, page 4 of 5 and the Company's response to Division 3-5

	Per Company	Company		Division Adjusted		Division Adjustment
7	Total Exp. Debt Svc & Capital Funds , Schedule RCS-1, p.1, line 23	$ 3,291,336				
8	Operating Reserve, Schedule RCS-1, p.5, col. A, line 160	$ 95,864		$ 47,932	[3]	$ (47,932)
9	Totals before calculating Operating Reserve	$ 3,195,472	[1]			

[2] Schedule RCS-2, line 10

[3] If applied to Company's proposed base, using 1.5% rather than BIUD's proposed 3.0% would reduce BIUD's amount by half.

Block Island Utility District
Interest and Principal on CFC Loan
Rate Year Ended December 31, 2020

Line No.	Description	Company Adjusted (A)	Division Adjusted (B)	Division Adjustment (C) = (B) - (A)
1	Interest on CFC Loan	$ 184,455	$ 209,908	$ 25,453
2	Principal Paid on CFC Loan	$ 113,064	$ 105,128	$ (7,936)
3	Interest and Principal on CFC Loan	$ 297,519	$ 315,035	$ 17,517

Notes and Source

Col.B: Company's response to Division 3-14:

	Payment Date	Beginning Balance	Total Payment	Principal Payment	Interest Payment	Ending Balance
4	3/31/2020	$5,774,311.13	$78,758.87	$25,923.92	$52,834.95	$5,748,387.21
5	6/30/2020	$5,748,387.21	$78,758.87	$26,161.13	$52,597.74	$5,722,226.08
6	9/30/2020	$5,722,226.08	$78,758.87	$26,400.50	$52,358.37	$5,695,825.58
7	12/31/2020	$5,695,825.58	$78,758.87	$26,642.07	$52,116.80	$5,669,183.51
8	2020 Totals:		$315,035.48	$105,127.62	$209,907.86	$5,669,183.51
9	3/31/2021	$5,669,183.51	$78,758.87	$26,885.84	$51,873.03	$5,642,297.67
10	6/30/2021	$5,642,297.67	$78,758.87	$27,131.85	$51,627.02	$5,615,165.82
11	9/30/2021	$5,615,165.82	$78,758.87	$27,380.10	$51,378.77	$5,587,785.72
12	12/31/2021	$5,587,785.72	$78,758.87	$27,630.63	$51,128.24	$5,560,155.09
13	2021 Totals:		$315,035.48	$105,127.62	$209,907.86	$5,560,155.09
14	3/31/2022	$5,560,155.09	$78,758.87	$27,883.45	$50,875.42	$5,532,271.64
15	6/30/2022	$5,532,271.64	$78,758.87	$28,138.58	$50,620.29	$5,504,133.06
16	9/30/2022	$5,504,133.06	$78,758.87	$28,396.05	$50,362.82	$5,475,737.01
17	12/31/2022	$5,475,737.01	$78,758.87	$28,655.88	$50,102.99	$5,447,081.13
18	2022 Totals:		$315,035.48	$105,127.62	$209,907.86	$5,447,081.13
19	3/31/2023	$5,447,081.13	$78,758.87	$28,918.08	$49,840.79	$5,418,163.05
20	6/30/2023	$5,418,163.05	$78,758.87	$29,182.68	$49,576.19	$5,388,980.37
21	9/30/2023	$5,388,980.37	$78,758.87	$29,449.70	$49,309.17	$5,359,530.67
22	12/31/2023	$5,359,530.67	$78,758.87	$29,719.16	$49,039.71	$5,329,811.51
23	2023 Totals:		$315,035.48	$105,127.62	$209,907.86	$5,329,811.51
24	3/31/2024	$5,329,811.51	$78,758.87	$29,991.09	$48,767.78	$5,299,820.42
25	6/30/2024	$5,299,820.42	$78,758.87	$30,265.51	$48,493.36	$5,269,554.91
26	9/30/2024	$5,269,554.91	$78,758.87	$30,542.44	$48,216.43	$5,239,012.47
27	12/31/2024	$5,239,012.47	$78,758.87	$30,821.91	$47,936.96	$5,208,190.56
28	2024 Totals:		$315,035.48	$105,127.62	$209,907.86	$5,208,190.56

Block Island Utility District
Voltage Conversion Capital Fund

Rate Year Ended December 31, 2020

Line No.	Description	Company Adjusted (A)	Division Adjustment (B)	Division Adjusted (C) = (A)+(B)
1	Voltage Conversion Capital Fund	$ 62,441	$ 33,743	$ 96,184
2	Division Adjustment to Sch. RCS-2		$ 33,743	

Notes and Source

Division adjustment maintains revenue neutrality