STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

In RE: The Narragansett Electric Company d/b/a Rhode Island Energy's SRP Investment Proposal for Electric Demand Response 2024-2026	)))))	Docket No. 24-06-EE

DIRECT TESTIMONY OF

William F. Watson, PhD

On Behalf of Rhode Island Division of Public Utilities and Carriers

March 22, 2024

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I. INTRODUCTION AND QUALIFICATIONS/PURPOSE OF TESTIMONY

Q: PLEASE STATE YOUR NAME AND THE BUSINESS ADDRESS OF YOUR EMPLOYER.

A: My name is William Franklin Watson. I am Principal and owner of Econalytics, LLC, a Virginia consulting firm located at 1603 Logwood Circle, Richmond, Virginia 23238, and am contracting with and filing testimony under Gregory L. Booth, PLLC ("Booth, PLLC"), mailing address 14660 Falls of Neuse Road, Suite 149-110, Raleigh, North Carolina 27614.

Q: ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS MATTER?

A: I am testifying on behalf of the Rhode Island Division of Public Utilities and Carriers (“Division”).

Q: WOULD YOU PLEASE OUTLINE YOUR EDUCATIONAL BACKGROUND?

A: I have a B.A. in Economics, a Master of Economics, and a PhD degree in Economics with a Statistics minor, all from North Carolina State University. In addition to a broad and general background in economics, the areas in which I concentrated for my doctoral degree were industrial organization, regulation and econometrics. My PhD research and dissertation was an analysis of the characteristics of energy substitution in United States manufacturing, a topic that has taken on new relevance in today’s push to find alternatives to carbon-based fuels. My resume is attached as Exhibit WFW-1.

Q: PLEASE STATE YOUR EXPERIENCE AND BACKGROUND.

A: I have more than 40 years of experience in the field of utility regulation performing a wide array of services. My first employment out of graduate school was in 1977 as the departmental economist with the North Carolina Attorney General’s office, which ultimately led to a position of Director of the Economic Research Division for the Public Staff of the

North Carolina Utilities Commission, an entity formed to represent the consumer in the regulation of utilities in North Carolina. There I led a team of economists in developing cost-of-capital, load forecasting, rates, and cost-of-service analysis on behalf of consumers of North Carolina electric, natural gas, telecommunications, and water and sewer utilities services, providing testimony on all these topics before the North Carolina Utilities Commission and the Federal Energy Regulatory Commission in contested hearings.

From 1981 to 1999, I worked with ElectriCities of North Carolina, a corporation of municipally-owned electric systems, where I held different positions at the middle and senior management level. My experience with ElectriCities centered on generation and transmission for forty-one locally owned municipal power distribution entities, developing wholesale rates, forecasting loads and budgeting, including long-term strategic planning, negotiating power purchase agreements with power suppliers on behalf of the municipalities, overall oversight of approximately 1400 megawatts of nuclear and coal-fired generation of which the Power Agencies had joint ownership, and development of plans for the building and operation of combustion turbine generation. I also developed and implemented a retail rate assistance program used by many municipal electric utilities. As Director of Power Supply, I managed staff with engineering and accounting backgrounds. As Director of Strategic Planning, I oversaw the transition of the North Carolina Power Agencies and the municipal distribution systems into the world of electric generation deregulation and served as the Chief Budget Officer and Planner for the organization.

From 1999 to 2006, I worked with North Carolina Electric Membership Corporation ("NCEMC"), the generation and transmission entity responsible for arranging, acquiring, operating and financing the power supply needs of twenty-three distribution electric cooperative entities. My work focus was on strategic planning and power supply. My experience included statistical analysis for wholesale rates, strategic plan development, scenario planning, acquisition analysis and pricing, long-term rate projections and working with the North Carolina Legislative Study Commission on the deregulation of the electric industry in North Carolina. As the dust began to settle on electric deregulation in North Carolina, my experience shifted to include statistical analysis and hourly load forecasting for power supply budgets, developing strategies to optimize Financial Transmission Rights revenue for NCEMC's participation in the PJM Interconnection, working with renewable energy suppliers and individual electric distribution cooperatives to develop mutually beneficial power purchase agreements, and liaison with the North Carolina Utilities Commission which included overall responsibility for the preparation of the NCEMC Annual Integrated Resource Plan.

From 2006 to 2009, I worked with PowerServices, Inc., a privately held electrical engineering and management consulting firm providing services to a range of small- to large-sized electric utilities for municipal, cooperative, investor-owned, and industrial electric power systems. My experience included analysis of cost-benefits of various projects, cost-of-service studies with rate design and recommendations, long-range planning for small to medium sized utilities, analysis of trends in the electric utility industry, review of regulatory filings and analysis of loss, and assessment of system valuation for acquisitions.

From 2009 to 2018, I worked with Old Dominion Electric Cooperative, a Virginia-based generation and transmission entity responsible for arranging, acquiring, operating and financing the power supply needs of eleven electric cooperative distribution entities in Virginia, Maryland and Delaware. My experience included ensuring that Old Dominion Electric Cooperative and its 11 electric distribution cooperatives met all federally mandated requirements to provide reliable and secure electric service to their consumers and as an integrated part of the national electric grid. This included assisting in the development of regulatory standards to meet energy policy requirements adopted by the United States Congress and under the supervision and enforcement of NERC.

In 2018, I formed Econalytics, LLC, a consulting firm specializing in working within the electric utilities industry in the application of the principles of economic analysis to meet existing operational challenges and to develop and implement strategic plans to operate successfully in the future environment.

In addition, I have held adjunct faculty positions at both North Carolina State University in Raleigh, NC and Virginia Commonwealth University in Richmond, VA, where I have taught a range of economics and statistics courses to undergraduate and graduate students.

While it has not been a focus of my employment, I have published papers on competition and monopoly, on the effectiveness of regulatory standards and on the effects of regulation on electric utilities.

Q: WHAT EXPERIENCE DO YOU HAVE IN ANALYZING AND IMPLEMENTING DEMAND RESPONSE PROGRAMS?

A: In my capacity as Director of Power Supply at ElectriCities of North Carolina, I was the senior manager responsible for the development and implementation of a demand response plan for 41 North Carolina municipal electric systems through two North Carolina Municipal Power Agencies. The Eastern Power Agency achieved an approximately 440 MW demand reduction on a total wholesale purchase of some 1,600 MW or over 25 percent demand reduction on the monthly coincident peak demand using a wide variety of demand control programs including industrial, commercial and residential programs ranging from water heater control and air conditioning control to industrial shift modifications and electric thermal storage at industrial and residential level just to name a few programs. I developed the analytical tools to assess the effectiveness of the proposed demand side management initiatives based on cost-benefit principles. Each program strategy was assessed against a counterfactual to determine the benefits relative to the cost. Given the variability in forecasting loads and predictions of future costs, this analysis included various scenario analyses using Monte Carlo simulations to determine probabilities of the costs of specific programs and program strategies exceeding the benefits. Recommendations for implementation of demand response program and strategies were based on the hierarchical, probability-based benefit-cost analysis.

The use of benefit-cost analysis is the underpinning for assessing the effectiveness of demand response programs as it is for other engineering projects. In the corporate positions that I have held, I have applied benefit-cost analysis a number of times. Some examples include analyzing the benefits and costs of multiple load control strategies constrained by excess capacity under uncertainty, analyzing benefits and costs of different strategies of stranded cost recovery from deregulation of electric generation, analyzing positions in power supply negotiations and lawsuit settlements, and various studies of benefits and costs of distributed generation.

Additionally, I have taught the application of benefit-cost analysis in my foundations of economics classes to undergraduate engineering students at Virginia Commonwealth University.

Q: HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT BEFORE REGULATORY COMMISSIONS AND POLICY-MAKING BODIES?

A: Yes. I have testified before the North Carolina Utilities Commission, the North Carolina General Assembly, and the Federal Energy Regulatory Commission, the Virginia State Corporation Commission, the Connecticut Public Utilities Regulatory Authority, and the

Rhode Island Public Utilities Commission.

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A: I am presenting testimony to delineate the Division's position on the analysis and proposed implementation of Rhode Island Energy's ("RIE" or "Company") Three Year (2024-2026) System Reliability Procurement Investment Proposal for its Electric Demand Response ("DR") Program which is also known as "ConnectedSolutions". This testimony is intended to outline areas of support and areas of concern, and to include recommendations which are intended to protect the ratepayer. The Division's position is based on information reviewed to date. Currently, there are pending data requests in this docket, and the schedule includes rebuttal and surrebuttal testimony. Based on the responses to outstanding data requests and any additional information filed in this docket, the Division reserves its right to provide an updated position during surrebuttal.

II. OVERVIEW OF RIE'S PROPOSAL

Q: PLEASE PROVIDE A BRIEF OVERVIEW OF THE COMPANY'S FILING.

A: The Company submitted its ConnectedSolutions proposal on February 8, 2024, and requested approval for effect June 1, 2024 for program years 2024 – 2026. Attachment 1 to my testimony is a budget summary for each year of the proposal, along with the proposed rate factors and estimated avoided electric bill costs. The proposed kWh factors for each year of the program are: $0.00224, $0.00143 and $0.00159. The Company is not currently collecting funds for the ConnectedSolutions Program. They propose to recover the 2024 budget amount over a 7-month period beginning June 1, 2024 which aligns with the proposed effective date. This shorter recovery period results in a higher factor than in subsequent years when the recovery period will be over the full calendar year. For 2024, the proposed factor, combined with the energy efficiency charge, would result in an all-in system benefit charge ("SBC") of

$0.01393/kWh, which would be the highest SBC for the Company that the Division is aware of.

Q: IN ATTACHEMENT 1, YOU INCLUDED THE ESTIMATED AVOIDED ELECTRIC BILL COSTS. WHAT IS THE SIGNIFICANCE OF THESE COSTS?

A: According to the Company's filing, their general approach to program design was first to set the Company's willingness to pay for peak demand reduction as determined by avoided electric bill cost. The testimony further stated that "The Company set its willingness to pay based on plausible avoided electric bill costs."[1] The Division's understanding is that with this approach, the electric bill benefits of the program would exceed the total costs of the program resulting in customers experiencing bill savings. The Division is in agreement with this approach because bill savings should be a primary objective of a demand response program. The Company estimated that the proposed program will generate annual bill savings of $1,877,900, $3,043,100 and $3,944,800 for the years 2024 – 2026 respectively.

III. EVALUATION PROCESS

Q: HOW DID YOU GO ABOUT ANALYZING THE COMPANY'S REQUEST FOR APPROVAL OF ITS THREE-YEAR PROPOSAL FOR ELECTRIC DEMAND RESPONSE?

A: After an initial review of the Company proposal and testimony, with supporting documentation, and participation in Company presentations, the analysis focused on two areas. First, I analyzed the derivation of the Company's avoided cost which is used to establish the target for its "willingness to pay" for DR pathways. Second, I analyzed the Company's estimate of the benefits from each of the pathways and the basis for developing

[1] Company's Joint Pre-Filed Direct Testimony, Page 16.

these estimates which includes forecasts for loads, future participation and the derivation of incentives for participation. This analysis included conferences with the Company which included discussion of the benefit-cost methodology and process.

Q: WOULD YOU PROVIDE AN OVERVIEW OF YOUR CONCERNS AND HOW YOU HAVE ORGANIZED YOUR TESTIMONY TO PRESENT YOUR POSITION?

A: While the Division generally supports the implementation of DR, and believes that there is ample industry evidence that DR programs are effective in reducing electric peak demand and bring financial savings to ratepayers, there are concerns that the evidence that the Company presented in its proposal for the specific pathways leaves enough questions so as to bring the conclusion that proceeding with these pathways on the Company's schedule with its underlying expectations will leave the Rhode Island ratepayer with too much exposure to failure to deliver the promised savings. The testimony first addresses the concerns about the Company's estimate of avoided cost. The importance of this estimate is that it is the determining factor setting the Company's "willingness to pay". If the promised benefits of any of the pathways, based on the estimate of avoided cost (or willingness to pay) do not exceed the cost of pathway implementation, then the assumption is that the pathway does not meet the standard to proceed. Second, the testimony addresses the derivation of the estimates of benefit-cost ratios for the proposed DR program. These benefit-cost estimates are the other part of the determination of whether the DR pathway meets the threshold to proceed. The benefits estimate for each pathway must exceed the avoided cost estimate.

IV. COMPANY ESTIMATE OF AVOIDED COST

Q: WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S ESTIMATE OF THE AVOIDED COST, THE TARGET TO BEAT FOR EACH PATHWAY BENEFITS?

A: In the Company proposal, witnesses state: "the Company identified the value of reducing 1 kilowatt ("kW") of peak load relative to the cost of serving 1 kW of peak load as funded through customer electric bills. This avoided electric bill value is primarily from avoided capacity costs and associated intrastate capacity demand reduction induced price effect ("DRIPE"), avoided regional network service ("RNS") charges, and avoided infrastructure (transmission and distribution) costs. For example, on average, serving 1 kW of peak load in 2024 would cost the customer base approximately $263."[2] A more granular definition of the avoided cost (or avoided electric bill) is the sum of Energy Savings, Capacity Savings, RNS, avoided Transmission Infrastructure and Distribution Infrastructure. Energy Savings has three components: reduced energy, energy DRIPE and energy price arbitrage. Capacity Savings has two components: capacity savings and capacity DRIPE. Each pathway has some variation in whether these components are applicable, but for purposes of demonstration, I will focus on $263/kW, which is the estimate from the Company testimony.

Q: DO YOU HAVE INDIVIDUAL ESTIMATES FOR EACH OF THESE COMPONENTS?

A: Yes. The Company provided the following component estimates for 2024.

Description	$/kW
Energy reduction	$ 0.64
Energy DRIPE	$ 0.03
Capacity reduction	$ 69.11
Capacity DRIPE	$ 21.79
RNS	$ 38.50
Transmission infrastructure	$ 13.40
Distribution infrastructure	$ 120.00
TOTAL	$ 262.83

[2] Company's Joint Pre-Filed Direct Testimony, Page 19.

The estimate for energy price arbitrage is $12.73, but this applies only to the battery storage pathway and would be added to this total to determine the avoided electric bill costs for that specific pathway. Also, the value of energy reduction does not apply to all pathways.

Q: HOW IS THIS ESTIMATE FOR 2024 AND SUBSEQUENT YEARS USED IN THE ANALYSIS?

A: As I have stated, this is the target by which to compare the estimated benefits for each pathway to assess whether it is appropriate to proceed. The Company develops a benefit-cost ("B-C") ratio to determine if the pathway estimated benefits exceeds its targeted cost. In a world with absolute certainty, a B-C ratio in excess of 1.0 indicate that benefits are expected to exceed costs.

Q: BASED ON THE ABOVE ESTIMATE OF AVOIDED COST AND THE SUBSEQUENT ESTIMATES FOR 2025 AND 2026, WHAT IS THE B-C RATIO THAT THE COMPANY PROJECTS?

A: The Company projections for B-C ratios are contained in the following table:

Rhode Island Test Benefit/Cost without Economic Benefit			
Year	**2024**	**2025**	**2026**
Residential	1.15	1.31	1.43
Commercial/Industrial	1.27	1.34	1.35
Grand Total	1.19	1.29	1.34

The Residential programs refer to the three DR pathways for residential customers, referred to as Bring Your Own Thermostat, Battery Storage and Electric Vehicle Dispatch. The Commercial/Industrial programs refer to the two DR pathways for C&I customers, Daily Dispatch and Targeted Dispatch. The Grand Total refers to all five pathways. It should be noted that these B-C ratios are inclusive of the payments to the Company for shareholder incentives as a cost of program.

Q: WHAT CONCERN DO YOU HAVE WITH THESE B-C RATIOS?

A: I have focused on the benefits side, leaving aside the estimates of program implementation, which are being addressed in data requests. The largest component is the estimate of the avoided distribution cost. For 2024, this component represents 46% of the entire estimate of avoided costs. The component proportions for 2025 and 2026 are similar in size. The Company recognizes that the estimate is "imperfect and imprecise" and that this component "has shown the most volatility in recent years."[3] With these provisos, the Company proposed a proxy estimate for the jurisdictional avoided distribution infrastructure as "$120/kW +/- $40/kW", and further that even this range of estimates may not be big enough.[4]

There are multiple reasons why the appropriate estimate of avoided distribution infrastructure might be $0/kW, particularly in situations where the distribution capacity is unconstrained, e.g., with excess capacity. First, there has been and is projected to be very little total system peak load growth. In this scenario, demand response options will not eliminate a capacity addition. Second, the distribution system substation and feeder diversity of peak demand further reduces the likelihood of a demand response component dispatched at the time of the generation peak reducing capacity projects. If a substation or feeder peaks at times other than the system coincident peak period driving generation peak, then a demand response at the time of the generation peak will not eliminate the capacity needed at the non-coincident peak period. Third, there are many asset condition projects including substations, major underground feeders and duct bank systems which are required for system reliability, equipment condition and age. As these are upgraded, they will include a level of increased capacity since that increased capacity comes at a very low incremental cost. This will significantly reduce the opportunities for demand response projects to reduce distribution

[3] Company's Joint Pre-Filed Testimony, Pages 19-20.
[4] Id., Page 20, footnote 5.

system costs. Fourth, RIE's risk tolerance philosophy may lead to more redundant capacity and backfeed capability and reliability enhancements. This is more distribution capacity which will not be avoided by demand response. Fifth, RIE is advancing FLISR (fault locating, isolation, sectionalizing and restoration also known as self-healing circuits) schemes which require added capacity capability to transfer loads between circuits. This further reduces the likelihood of avoided distribution system capacity cost savings from demand response. The Infrastructure, Safety and Reliability Plan ("ISR") process and Area Studies and Long-Range Plan all support this list of issues which result in the likelihood of much lower distribution system avoided costs if any savings at all. Sixth, the ever-increasing level of distributed energy resources ("DER") and large generation interconnection is creating new and larger substations, subtransmission and distribution lines all with more capacity. This further reduces the likelihood of avoided distribution cost from demand response. It is more likely than not that the only savings from demand response will be the reduction in supply and transmission costs to the extent that Rhode Island demand response outperforms other states sharing in the generation and transmission costs. What this means is Rhode Island needs a demand response program which performs at least as well as surrounding states to avoid increased power cost through the transfer of shared cost between states to Rhode Island.

By way of comparison, a scenario where the avoided distribution capacity cost is $0/kW significantly reduces the B-C ratio when compared to the Company estimates as shown in italics in the following table.

Rhode Island Test Benefit/Cost without Economic Benefit			
Year	**2024**	**2025**	**2026**
Residential	1.15/*0.71*	1.31/*0.82*	1.43/*0.92*
Commercial/Industrial	1.27/*0.78*	1.34/*0.84*	1.35/*0.85*
Grand Total	1.19/*0.73*	1.29/*0.81*	1.34/*0.85*

Q. DO YOU HAVE ADDITIONAL OBSERVATIONS OR RECOMMENDATIONS RELATED TO THE CALCULATION OF AVOIDED DISTRIBUTION INFRASTRUCTURE?

A: Yes. The Company relies on a theoretical model to calculate a system avoided distribution infrastructure cost which I have highlighted that, in practical terms, appear overstated given the level of available distribution capacity, minimal load growth, and significant planned capital investments that would progress regardless of a DR program. Although it is the most significant component of "willingness to pay" there is limited support for the calculation within the filing. I have not derived a specific adjustment but recommend that the methodology, calculation, and underlaying data be addressed in detail within this proceeding. This would create potential adjustments and ultimately instill more confidence in the Company's BC analysis for ongoing DR program proposals.

Q: THE COMPANY'S ESTIMATE OF AVOIDED ELECTRIC BILL COSTS CONTAINS A COMPONENT FOR DEMAND REDUCTION INDUCED PRICE EFFECT (DRIPE). WHAT IS THE IMPACT OF THIS COMPONENT?

A: The DRIPE effect is grounded in basic economics. By another name it is the impact of what economists refer to as supply price elasticity. In 2024, the Company's estimate of the effect of DRIPE is mostly in the capacity market and while it is not the predominant feature of the overall estimate of avoided cost, it is significant. The concern that I have is the variability in the estimate of Capacity DRIPE over time. This is revealed in the most recent update in the Rhode Island estimates of Capacity DRIPE published by Synapse Energy in February 2024. The increases in the 2021 estimates to the same estimates made three years later are shown as follows:

Synapse Energy Capacity DRIPE estimates			
	2024	**2025**	**2026**
AESC - 2021	$21.79/kW	$22.44/kW	$23.12/kW
AESC - 2024	$37.14/kW	$78.49/kW	$132.46/kW
% Increase	70%	250%	473%

The variation in the estimates brings into question not only the accuracy of the forecasts from the estimates in 2021 to the next in 2024, but also drastic change in the rate of increase from the 2024 to 2026 estimates made in 2021 (6.1%) to those made in 2024 (257%).

Q: WHAT IMPACT WILL THIS VARIABILITY HAVE ON THE B-C RATIOS?

A: My understanding is that this variability in the periodic updates in DRIPE estimates is not unusual, based on the magnitude of changes that have occurred in the periodic updates in the DRIPE estimates done by Synapse Energy Economics. The conclusion that I reach is that with this kind of variability, there is a significant risk of being wrong and by a wide margin. In the Company's proposal, with the proposed incentive payments, it is the electric ratepayer who will bear the risk.

Q: IS THERE SIGNIFICANT VARIABILITY IN OTHER REVISED ESTIMATES IN THE AESC-2024 REPORT?

A: Yes, there is an update in the estimates of Capacity for the years 2024-2026 that are significantly lower than those used by the Company from the AESC-2021 report. These are shown below.

Synapse Energy Capacity estimates			
	2024	**2025**	**2026**
AESC - 2021	$69.11/kW	$71.93/kW	$73.97/kW
AESC - 2024	$30.10/kW	$44.49/kW	$66.30/kW
% Increase	-56%	-38%	-10%

The impact of these lower capacity cost estimates is that the avoided cost of a kW of demand reduction will be somewhat lower and will lower the resulting B-C ratio without an offsetting reduction in the cost to implement the DR pathways.

V. COMPANY ESTIMATE OF PATHWAY BENEFITS

Q: WHAT CONCERNS DO YOU HAVE WITH REGARD TO THE COMPANY ESTIMATES OF THE BENEFITS FROM THE PROPOSED DR PATHWAYS?

A: First, a general comment on the methodology. In determining the benefit-cost ratios, the Company uses two estimates that raise concerns: the discount rate of 1.47% and the estimated future inflation rate of 1.35%. The discount rate should represent the time value of money. As it applies to determining the Company's "willingness to pay" or "avoided electric bill costs" it should be a time preference for money. Time preference is based on the concept of opportunity cost – that which is foregone when financial resources are committed to a project. The discount rate, when trying to assess the consumer's commitment to DR projects through higher electric bills, should represent the consumer's time preferences.

Q: HOW DOES THIS RELATE TO THE INFLATION RATE?

A: Consumers' (as well as the Company shareholders') time preference, at the very least should exceed the rate of inflation by the real opportunity cost to the consumer of forgoing current use of funds for future returns as are anticipated by participation in these DR pathways. Consumers have an aversion to losing ground to inflation over time. The discount rate estimates of 1.47% used in the Company analysis exceeds the inflation estimate of 1.35% by a mere 0.12%. A more reasonable estimate of consumers' real time preference can be inferred from looking at spreads in similar securities that are inflation-adjusted versus those that are not. Ten-Year Government bond spreads for the calendar year 2023 show an average annual spread of 2.28% with very little variation from month to month. It is reasonable to assume that the inflation premium in the discount rate should be close to this number.

Q: IS THE INFLATION RATE ESTIMATE OF 1.35% REALISTIC?

A: In my opinion, it is not. Inflation in the United States has recently been high by near historical standards and while it has abated recently, the most recent Bureau of Labor Statistics annual CPI index shows a 3.1% increase from last year at this time. Further, the Federal Reserve Board of Governors, which has established an inflation target rate of 2% annually, has indicated that it is not ready to signal that it has concluded that the present high inflation rates are fully abated. For these reasons, I would suggest that a more realistic estimate of inflation for the period 2024-2026 should be in the range of 2-3%.

Q: WHAT IS YOUR RECOMMENDATION FOR A REASONABLE ESTIMATE OF A DISCOUNT RATE TO USE IN ASSESSING THE BENEFITS AND COSTS OF THE COMPANY'S DR PATHWAYS?

A: In addition to the inflation and time preference components of a discount rate under the concept of opportunity cost, there is a component of risk involved in tying up resources into a project path. Once you have invested in projects there is no guarantee that expectations will be met. Examples of risk in the DR pathways that the Company is proposing are: 1) projected peak load growth not materializing, 2) changes in the capacity market prices, 3) inflation, 4) changes in government policy, and many more.

The Company has set a target "price to beat" of $263/kW based on its estimate of the avoided costs of adding capacity to meet a kW of additional demand. Implicit in this estimate is the cost of capital for Company shareholders to expand distribution and transmission capacity as well as the cost of capital for shareholders of the generators that supply generation and capacity. The RIE implied cost of capital which contains all three of the above-mentioned elements – time preference, inflation and risk – is its weighted average cost of capital (“WACC”), of which this Commission has weighed in as being a fair rate of return. I suggest that this is also a reasonable estimate for a discount rate to assess the benefits of the Company’s proposed DR pathways.

Q: WHAT IMPACT WOULD YOUR TWO RECOMMENDATIONS FOR THE INFLATION RATE AND THE DISCOUNT RATE HAVE ON THE COMPANY’S ESTIMATES OF ITS B-C RATIOS?

A: Making these two adjustments to the Company’s BCA model will reduce the Grand Total B-C ratios from 1.19 to 1.14 for 2024, from 1.29 to 1.25 for 2025 and from 1.34 to 1.32 for 2026. When the B-C margins are thin to begin with, these adjustments matter.

It should also be noted that most of these DR programs can be expected to last more than just the three years for which the Company’s proposal covers in this docket. The longer time period that a discount rate is applied to get to a present value in the determination of benefits and costs, the more significant its magnitude becomes to the end result.

VI. CONCLUSIONS AND RECOMMENDATIONS

Q: BASED ON THE CONCERNS YOU HAVE EXPRESSED, WHAT ARE YOUR CONCLUSIONS ABOUT THE COMPANY’S ESTIMATE OF THE BENEFITS OF THE PROPOSED DR PROGRAM RELATIVE TO THE COSTS?

A: Overall, the Company presents a picture of certainty in the estimates of its avoided cost of capacity expansion required to meet anticipated load growth through traditional utility expansion. While the Company expresses its understanding that there is considerable uncertainty caused by the variability in the estimates of the components of its avoided cost, there is no attempt to assess the impact of this uncertainty. Further, the Company utilizes some assumptions about the discount rate and the inflation rate in the derivation of benefits that I believe are unrealistic.

The specific areas of uncertainty in the estimation of avoided costs addressed above are: 1) distribution infrastructure costs, 2) the impact of DRIPE, and 3) capacity costs. These three components represent approximately three-fourths of the total avoided cost estimate. The drastic variability in these three components brings into question whether there is a reasonable probability that the benefits will outweigh the costs of the proposed DR program expansion.

In addition, there are other areas of uncertainty that impact the analysis. These include forecast error in peak load forecasts, the impact of unanticipated distributed energy resources, the differences in actual and projected customer participation and opt-out rates.

Finally, the impact of the unrealistically low assumptions on the discount and inflation rates included in the benefits analysis overstates the benefits relative to the costs of the Company's DR program.

With all of these uncertainties, there is an overall concern about the propriety of adopting all of the recommendations that the Company has proposed with respect to its DR program. And while the Division supports the overall goals of demand response, the conclusion that I come to in support of this position is that the DR program in theory is on solid grounds and should be continued in its present state, but that the practical application as proposed by the Company is too ambitious given these uncertainties.

Q: DO YOU HAVE RECOMMENDATIONS BASED ON THESE CONCLUSIONS?

A: Yes. The Company's electric consumers ultimately bear the burden of the costs of decisions based on incomplete information on benefits when these decisions turn out to be overstated. As stated above, the estimate of avoided cost which serves the basis of the counterfactual upon which the impact of the five DR pathways is assessed is made up of three components which constitute roughly 75% of the overall estimate and which have been demonstrated to have significant variability in their makeup, especially when looked at over time. I would recommend that the Company factor in this uncertainty into its analysis with a detailed sensitivity analysis to get a sense of the probability of overstating the benefits of the DR program. I recommend that the Company update its estimates of Capacity and DRIPE with the newer 2024 AESC estimates and include estimates of variability of these estimates in its analysis. I also recommend that the Company revisit and fully support its methodology and calculation for avoided distribution since theoretical reductions appear unrealistic for a system with adequate capacity and minimal load growth, among other items. Additionally, the Company should establish, to the maximum extent possible, the likely effectiveness of other New England utility demand response programs and the cost shifting to Rhode Island these programs in other states may create on the Rhode Island rate payers if Rhode Island fails to meet or exceed the demand reductions achieved in other states sharing power supply and transmission costs with Rhode Island. Finally, I would recommend that the Company use the Company's approved weighted average cost of capital as a proxy for its discount rate and use a more reasonable estimate of future inflation.

The Division stands behind the ongoing efforts to operate the Company more efficiently and to reduce its carbon emissions. However, it does not believe that the present analysis has presented a compelling case to expand the existing efforts without an undue risk to the Company's electric consumers.

Q: AS FAR AS THE SPECIFICS THAT THE COMPANY PROPOSES, DO YOU HAVE ANY RECOMMENDATONS?

A: Yes, in addition to pulling back the reins on the Company's overall proposed 3-year program expansion to clear up some of the uncertainties and in order to continue to support the overall purpose of DR, I propose the following: 1) support for reducing the $400/kW multiyear incentive rate to $225/kW for the Residential and Small Business Battery pathway, 2) Maintain the current upfront enrollment incentive rate at $25/kW for the Bring Your Own Thermostat pathway, 3) Disallow the performance incentive mechanism that accrues to the Company until such time as the Company can identify with more certainty, the actual benefits from these programs.

Q: DOES THIS CONCLUDE YOUR TESTIMONY?

A: Yes.

Attachment 1

Description	Program Budget 2024	2025	2026
Planning and Administration	$ 189,600	$ 187,900	$ 191,400
Marketing	17,500	17,500	17,500
Customer Rebates/Incentives	7,865,000	7,981,500	8,660,100
Sales, Tech & Training	993,900	1,221,000	1,433,300
Performance Incentive	472,100	760,800	998,800
Sub-Total	9,538,100	10,168,700	11,301,100
EERMC/OER	272,000	282,200	309,100
Total Program Budget	**$ 9,810,100**	**$ 10,450,900**	**$ 11,610,200**
Proposed SRP Factor - kWh	$0.00224	$0.00143	$0.00159

Description	Avoided Electric Bill Costs 2024	2025	2026
Summer Generation	$ 3,058,000	$ 3,570,000	$ 4,134,000
Capacity DRIPE	964,000	1,114,000	1,292,000
Transmission	593,000	674,000	769,000
Distribution	5,309,000	6,036,000	6,888,000
Summer - Peak	6,000	8,000	10,000
Avoided RNS	1,704,000	2,023,000	2,431,000
Energy Price Arbitrage	64,000	69,000	81,000
Total Avoided Electric Costs	**$ 11,698,000**	**$ 13,494,000**	**$ 15,605,000**
Bill Savings (Avoided Costs less Budget)	$ 1,887,900	$ 3,043,100	$ 3,994,800

RESUME OF:
WILLIAM FRANKLIN WATSON, PH.D.

Education

B.A., Economics, North Carolina State University
Master of Economics, North Carolina State University
Doctor of Philosophy with major in Economics and minor in Statistics,
North Carolina State University

Experience

January 2018 to Present
Principal, Econalytics, LLC

Econalytics is a consulting firm specializing in working with utilities in the application of the principles of economic analysis to meet existing operational challenges and to develop and implement strategic plans to operate successfully in the future environment.

August 2013 to May 2021
Adjunct Faculty member, Virginia Commonwealth University, School of Business

Taught undergraduate and graduate classes in economics and statistics.

January 2009 to January 2018
Regulatory Compliance Specialist
Old Dominion Electric Cooperative (ODEC)
www.odec.com

ODEC is a generation and transmission cooperative based in Richmond, VA that provides wholesale power to 11 full requirements electric distribution cooperatives in the states of Virginia, Delaware and Maryland.

Experience includes ensuring that ODEC and its 11electric distribution cooperatives met all federally mandated requirements to provide reliable electric service to their customers and as an integrated part of the national electric grid with entities such as the PJM Interconnection. This includes assisting in the development of regulatory standards to meet the energy policy requirements adopted by the United States Congress

February 2006 to December 2008
Financial Analyst
PowerServices, Inc.
www.powerservices.com

PowerServices, Inc. was a management consulting firm based in Raleigh, NC specializing in small to medium sized electric utilities.

Experience included analysis of cost-benefits of various projects, cost-of-service studies with rate design and recommendations, long-range planning for small to medium sized utilities, analysis of trends in the electric utility industry, review of regulatory filings and analysis of loss and assessment of system valuation for acquisitions.

January 2004 to January 2006
Senior Resource Analyst
Power Supply Division
North Carolina Electric Membership Corporation (NCEMC)
www.ncemc.com

NCEMC is a generation and transmission cooperative that provides wholesale power to 22 full requirements and 4 partial requirements electric distribution cooperatives in the state of North Carolina.

Experience included statistical analysis and hourly load forecasting for power supply budgets, developing strategies to optimize financial transmission right revenue for NCEMC's participation in the PJM Interconnection, working with renewable energy suppliers and individual electric distribution cooperatives to develop mutually beneficial power purchase agreements, liaison with North Carolina Utilities Commission which included overall responsibility for the preparation of the NCEMC Annual Integrated Resource Plan.

October 1999 to January 2004
Director, Strategic Analysis
Strategic Services Division
North Carolina Electric Membership Corporation
www.ncemc.com

Experience included statistical analysis for wholesale rates, strategic plan development, scenario planning, acquisition analysis and pricing, long-term rate projections and working with the NC Legislative Study Commission on the deregulation of the electric industry in North Carolina.

June 1981 to October 1999
Various positions with ElectriCities of North Carolina, including senior management
www.electricities.com

ElectriCities of North Carolina is an umbrella organization for North Carolina Municipal Power Agency Number 1 and North Carolina Eastern Municipal Power Agency (Power Agencies). These two Power Agencies are the wholesale suppliers of 19 and 32 municipally owned electric utilities in North Carolina, respectively.

Experience included development of wholesale rates for the Power Agencies, load forecasting and budgeting including long-term strategic planning, power purchase agreement negotiations with power suppliers, overall oversight of approximately 1400 megawatts of nuclear and coal-fired generation of which Power Agencies had joint ownership, development of plans for combustion turbine generation. I also developed a retail rate assistance program for Power Agency municipal utilities. As Director of Power Supply, I managed a staff of 6-8 people with engineering and accounting backgrounds and served as the Chief Budget Officer and Planner for the organization.

February 1978 to June 1981
Director of Economic Research Division
North Carolina Utilities Commission
(NCUC)
www.pubstaff.commerce.state.nc.us

Experience included preparing expert rate and rate of return testimony in electric, natural gas telephone and water utilities petitions before the NCUC for increase in rates. Testified in numerous NCUC cases and one Federal Energy Regulatory Commission case subject to cross-examination by utilities' counsel. Also responsible for load forecasting and overall economic and statistical analysis of the utility industry. Managed a staff of 5 economists. Also worked on various antitrust cases providing expert economic analysis with the North Carolina Department of Justice.

Academic Experience

Adjunct Faculty member of the School of Business, Virginia Commonwealth University Taught the following courses.

- Foundations of Economics
- Business Statistics II

Adjunct Assistant Professor, Department of Economics, North Carolina State University. Taught the following courses

- Introduction to Macroeconomics
- Economics of the Firm
- Statistics for Business Majors (first semester course)
- Statistics for Economists (second semester course)

Military
Commissioned Second Lieutenant, US Army Reserves, Armor Branch
Honorable Discharge from US Army Reserves, First Lieutenant

Other Accomplishments and Achievements

- Member and former chairman of the Graduate School Board of Advisors, North Carolina State University
- Former member of the College of Management Board of Advisors and former chairman of the Faculty Advisory Committee, North Carolina State University
- Former chair of the American Public Power Association's Pricing and Market Analysis Committee

Recent Publications

"NERC mandatory reliability standards: a 10-year assessment", The Electricity Journal, March 2017.

"Reforming reliability standards: A perspective from economics", The Electricity Journal, April 2018