STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 22-XXX

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

Annual Retail Rate

DIRECT TESTIMONY

OF

JOHN D. WARSHAW

March 22, 2022

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I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your full name, business address, position, and responsibilities.

A. My name is John D. Warshaw, and my business address is 15 Buttrick Road, Londonderry, New Hampshire. I am the Manager, Electric Supply for Liberty Utilities Service Corp., which provides services to Liberty Utilities (Granite State Electric) Corp., d/b/a Liberty ("Liberty" or "the Company"). I oversee the procurement of power for Energy Service for Liberty as well as the procurement of renewable energy certificates ("RECs"). I am also responsible for monitoring costs and activities relative to transmission service provided to the Company.

Q. Please describe your educational background.

A. I graduated from the State University of New York Maritime College in 1977 with a Bachelor of Science in Nuclear Science. I received a Master's in Business Administration from Northeastern University in 1986. In 1992, I earned a Master of Arts in Energy and Environmental Management from Boston University.

Q. What is your professional background?

A. In November of 2011, I joined the Company as Manager, Electric Supply. Prior to my employment at Liberty Utilities Service Corp., I was employed by National Grid USA Service Company ("National Grid") as a Principal Analyst in Energy Supply – New England from 2000 to 2010. In that position I conducted a number of solicitations for wholesale power to meet the needs of National Grid's New England distribution companies. I also administered both short-term and long-term power purchase agreements for National Grid's New England distribution companies. Prior to my employment at National Grid, I was employed at COM/Energy (now NSTAR) from 1992 to 2000. From 1992 to 1997, I was a Rate Analyst in Regulatory Affairs at COM/Energy responsible for supporting state and federal rate filings. In 1997, I transferred to COM/Electric to work in Power Supply Administration.

Q. Have you previously testified before the New Hampshire Public Utilities Commission ("Commission")?

A. Yes. I most recently provided written and oral testimony before the Commission in Docket No. DE 21-087 on December 22, 2021.

Q. Have you testified before any other state regulatory agencies?

A. Yes. I have testified before both the Massachusetts Department of Public Utilities and the Rhode Island Public Utilities Commission regarding electric supply and renewable portfolio procurement activities.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. My testimony addresses the estimated 2022 transmission expenses for Liberty. First, I will summarize the various transmission services provided to Liberty and describe how Liberty pays for those services. Second, I will provide testimony supporting the forecast of transmission expenses that Liberty expects to incur in 2022. As described more fully in Section IV of my testimony, the Company forecasts an increase of $2,110,950 in prospective transmission expenses for calendar year 2022 as compared to the forecast provided for calendar year 2021 in Docket No. DE 21-063.[1]

III. SUMMARY OF TRANSMISSION SERVICES PROVIDED TO LIBERTY

Q. Please summarize what transmission services Liberty receives from ISO New England Inc. (the "ISO" or "ISO-NE") under rate schedules approved by the Federal Energy Regulatory Commission ("FERC").

A. Liberty receives transmission services under the ISO New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff") as follows:

1. Section II (Schedules 1, 2, 9, and 16) of the ISO Tariff provides for Regional Network Service ("RNS");
2. Section IV.A – ISO Funding Mechanisms provides for the recovery of ISO's Administrative Services; and
3. Section II, Schedule 21 of the ISO Tariff provides for Local Network Service ("LNS") from the New England Power Company ("NEP").

Q. Please describe further the types of transmission services that are billed to Liberty under the ISO Tariff.

A. New England's transmission rates utilize a highway/local pricing structure. That is, Liberty receives regional transmission service over "highway" transmission facilities under Section II of the ISO Tariff (also known as RNS) and receives local transmission service over local transmission facilities under Schedule 21 of the ISO Tariff (also known

1 The forecast for calendar year 2021 was $26,891,183. The actual amount for 2021 was $27,125,953.

as LNS). Additionally, a number of administrative services are provided by ISO-NE under Section IV.A of the ISO Tariff.

A. Explanation of ISO Tariff Services, Rates, and Charges

Q. Please explain the services provided to Liberty under the ISO Tariff.

A. Section II of the ISO Tariff provides access over New England's looped transmission facilities, more commonly known as Pool Transmission Facilities ("PTF") or bulk transmission facilities. In addition, the ISO Tariff provides for Ancillary Services (Black Start, Reactive Power, and Scheduling, System Control, and Dispatch Services) as described more fully later in this testimony.

Q. How are the costs for RNS recovered?

A. The ISO Tariff's RNS Rate ("RNS Rate") (Section II - Schedule 9 of the ISO Tariff) recovers the RNS costs, and is determined annually based on an aggregation of the transmission revenue requirements of each of the Participating Transmission Owners ("PTO") in New England, calculated in accordance with a FERC-approved formula in a single, "postage stamp" rate in New England. FERC opened Docket No. EL16-19 to investigate the reasonableness of the formula rates and protocols used to develop both RNS and LNS. A Settlement Agreement was reached and filed with FERC on June 15, 2020 (FERC Docket No. ER20-2054) resolving all issues regarding the RNS and LNS formula rates. FERC issued its order approving the settlement on December 28, 2020. A compliance filing was made on January 27, 2021, setting the effective date of the formula rate revisions to be January 1, 2022. A portion of the Settlement Agreement describes the establishment of more transparent transmission rate review protocols. These protocols were in effect on June 15, 2021, giving interested parties sufficient time to review and challenge the rates to be effective on January 1, 2022. The Participating Transmission Owners Committee submitted its filing under these protocols on July 30, 2021, with the FERC Protocols required interested parties to file a formal challenge of the proposed rates by January 31, 2022. It is my understanding that no challenges were filed, and the rates went into effect on January 1, 2022.

Q. Please describe the ISO-NE System Restoration and Planning Service, Reactive Supply and Voltage Control, and Scheduling, System Control, and Dispatch Services that are included in the ISO Tariff.

A. ISO-NE System Restoration and Planning Service (Section II - Schedule 16 of the ISO Tariff), also known as Black Start Service, is necessary to ensure the continued reliable operation of the New England transmission system. This service allows for the ISO to pay generators who have the capability of supplying load and the ability to re-start without an outside electrical supply to re-energize the transmission system following a system-wide blackout.

Reactive Supply and Voltage Control (Section II - Schedule 2 of the ISO Tariff), also known as Reactive Power Service, is necessary to maintain transmission voltages within acceptable limits on the ISO-NE transmission system and allows for the payment to generators or other facilities that have the capability to produce or absorb reactive power.

Lastly, Scheduling, System Control, and Dispatch Service ("Scheduling & Dispatch Service") consists of the services required to schedule the movement of power through, out of, within, or into the ISO-NE Control Area over the PTF and to maintain System Control. Scheduling & Dispatch Service also provides for the recovery of certain charges that reflect expenses incurred in the operation of satellite dispatch centers.

Q. How are the ISO-NE charges for Black Start and Reactive Power assessed to Liberty?

A. ISO-NE assesses charges for Black Start and Reactive Power Services to Liberty each month based on Liberty's proportionate share of its network load to ISO-NE's total network load.

Q. How are the charges for Scheduling & Dispatch Service assessed to Liberty?

A. Charges for Scheduling & Dispatch Service are assessed to Liberty through three separately charged tariffed services.

The first charge is for the expenses incurred by ISO-NE in providing these services and is recovered under Schedule 1 of Section IV.A of the ISO Tariff. These costs are allocated to Liberty each month based on an annually filed FERC-approved fixed rate times Liberty's monthly Network Load.

The second charge is for the costs incurred by the individual transmission owners in providing Scheduling & Dispatch Service over PTF facilities, including the costs of operating local control centers, and are recovered under Section II, Schedule 1 of the ISO Tariff. These costs are allocated to Liberty each month based on a formula rate that is determined each year based on the prior year's costs incurred times Liberty's monthly Network Load.

The final charge is for the cost of Scheduling & Dispatch Service for transmission service over transmission facilities other than PTF that are charged under Schedule 21 of the ISO Tariff. Thus, the three types of Scheduling & Dispatch costs are similar but are charged to Liberty through three different tariff mechanisms.

Q. What additional administrative services and/or charges flow through to Liberty under Section IV.A of the ISO Tariff?

A. Liberty also incurs charges pursuant to Section IV.A, Schedule 5 of the ISO Tariff. Schedule 5 provides for the collection of the New England States Committee on Electricity's ("NESCOE") annual budget. NESCOE is the "not-for-profit entity that represents the collective perspective of the six New England Governors in regional electricity matters and advances the New England states' common interest in the provision of electricity to consumers at the lowest possible prices over the long-term, consistent with maintaining reliable service and environmental quality." *See* www.nescoe.com.

Q. How are the ISO Tariff Administrative Services charges assessed?

A. ISO-NE assesses the charges in Section IV.A based upon stated rates pursuant to the ISO Tariff. These stated rates are adjusted annually when ISO-NE files a revised budget and cost allocation proposal to become effective January 1 each year. Liberty is charged the stated rate for these services as part of ISO-NE's monthly billing process, based on its Network Load for Section IV.A Schedule 1 and Schedule 5 charges.

B. Explanation of Schedule 21 NEP Tariff Services, Charges, and Credits

Q. What services are provided to Liberty under Schedule 21 of the ISO Tariff?

A. Schedule 21 governs the service that NEP provides to Liberty over its local, non-highway transmission facilities, considered non-PTF facilities ("Non-PTF"). The service provided over the Non-PTF is referred to as Local Network Services ("LNS"). NEP posted fixed LNS annual rates effective January 1, 2022, in compliance with FERC's approval of the Settlement Offer in Docket ER20-2054, as mentioned above. These fixed 2022 rates will be trued-up to NEP's actual costs in June 2023 and would be included in the LNS rates effective January 1, 2024. NEP also provides metering, transformation, and certain ancillary services to Liberty to the extent such services are required by Liberty and not otherwise provided under the ISO Tariff.

Q. Please explain the metering and transformation services provided by NEP.

A. NEP separately surcharges the appropriate customers for these services. NEP provides metering service when a customer uses NEP-owned meter equipment to measure the delivery of transmission service. NEP provides transformation service when a customer uses NEP-owned transformation facilities to step down voltages from 69 kV or greater to a distribution voltage.

Q. Are there any other transmission services for which NEP assesses charges to Liberty?

A. Yes. Liberty relies on the specific distribution facilities of NEP's affiliate, Massachusetts Electric Company ("Mass Electric"), which provides for NEP's use of such facilities pursuant to the Integrated Facilities provision of NEP's FERC Electric Tariff No. 1

service agreement with Mass Electric. NEP, in turn, uses these specific distribution facilities to provide transmission service to Liberty. Therefore, Liberty is also subject to a Specific Distribution Surcharge for its use of these facilities.

Q. What is the credit in Schedule 21 charges that NEP provides to Liberty in its monthly invoice?

A. As a result of National Grid's sale of Liberty in 2012, NEP (a National Grid affiliate) uses certain distribution facilities of Liberty to provide service to generation customers of NEP. An Integrated Facilities Supplement to Schedule 21 of the ISO Tariff provides Liberty with a credit in exchange for NEP's continued use of Liberty's facilities to serve NEP's generation customers.

IV. ESTIMATE OF LIBERTY'S TRANSMISSION EXPENSES

Q. Was the forecast for Liberty's transmission and ISO expenses for 2022 prepared by you or under your supervision?

A. Yes. I estimate the total transmission and ISO-NE expenses (including certain ancillary services) for 2022 to be approximately $29,002,132, as shown in Schedule JDW-1, page 1 of 2. This equates to an increase of $2,110,950 as compared to the forecast for 2021 provided in Docket No. DE 21-063, as shown on Schedule JDW-1, page 2 of 2.

Q. How have the ISO Tariff charges for RNS shown on line 3 of Schedule JDW-1 been forecasted?

A. I estimated the 2022 RNS charges by applying the posted RNS rate of $142.78 per kW-year, effective January 1, 2022. This is an increase of $13.52 per kW-year from the rate that was effective on January 1, 2021, and an increase of $4.78 per kW-year for the rate that was effective on June 1, 2021, and that was estimated in Docket No. DE 21-063. The combination of current rates compared to the load forecast used in Docket No. 21-063, results in an estimated increase of $1,532,250 as shown in column 3, line 3 of Schedule JDW-1, page 2 of 2. To obtain the estimate of RNS costs that would be charged to Liberty, as shown in column 2 of Schedule JDW-2, I multiplied the monthly rate by Liberty's monthly network load, as shown for each month in column 1 of Schedule JDW-2.

The main reason for the estimated increase in costs for 2022 as compared to what was filed in 2021 is that the transmission owners in New England continue to replace aging equipment and address reliability issues regarding the delivery of supply from both conventional and renewable resources.

These improvements to the New England transmission system are the result of a regional planning process coordinated by the ISO-NE through an extensive stakeholder process to identify the various needs of the New England system and how to meet those needs reliably and at the least cost.

Q. Schedule JDW-1 also includes estimated ISO-NE charges for Black Start, Reactive Power, and Scheduling and Dispatch. How were these costs forecasted?

A. In estimating the expected costs of the ISO-NE charges, I used the same approach as in previous filings. The Black Start costs shown on line 5 of Schedule JDW-1 were derived in two steps. First, as shown in Section II of Schedule JDW-3, I estimated the cost for

Black Start Service by, as a starting point, summing Liberty's actual monthly ISO-NE Black Start expenses for 2021 (Line 5). I divided this estimate by Liberty's 2021 Peak Load to calculate an estimated annual rate, as shown on line 7. I then calculated a monthly rate (annual rate divided by 12), as shown on line 8. To obtain the estimate of Black Start costs that would be charged to Liberty, as shown in column 4 of Schedule JDW-2, I multiplied the monthly rate by Liberty's monthly network load, as shown for each month in column 1 of Schedule JDW-2. Using this methodology, I estimate an allocation of $210,598 for 2022.

Q. How have you estimated Reactive Power costs for Liberty?

A. I calculated the estimated Reactive Power costs for Liberty by using actual Liberty costs for 2021 as shown in Section I of Schedule JDW-3. The annual rate was determined by dividing the total Reactive Power costs charged to Liberty (Line 1) by Liberty's peak 2021 Network Load. The monthly rate (annual rate divided by 12) was then multiplied by Liberty's monthly network load, as shown in column 1 of Schedule JDW-2, to determine the estimated charges for Reactive Power Service shown in column 5 of that same schedule. Using this methodology, I estimate an allocation of $116,459 for 2022.

Q. How did you forecast the Scheduling and Dispatch costs shown on line 4 of Schedule JDW-1, page 1?

A. My estimate is shown in column 3 of Schedule JDW-2. This amount was derived by using the currently effective OATT Schedule 1 rate of $1.86858 per kW-year, divided by 12, and further multiplied by Liberty's monthly network loads for 2021 as shown in column 1 of Schedule JDW-2.

Q. Have you included any Reliability Must Run ("RMR") contract charges to Liberty for 2021?

A. No. Reliability Must Run Agreements guarantee payments to generators that are needed to ensure reliability. To obtain an agreement, a generator must receive verification from ISO-NE that it is needed for reliability and must demonstrate that it is unable to cover its operating costs with revenue from other sources. Liberty has not incurred any RMR contract charges as there have been no RMR contracts for the New Hampshire reliability region over the past year. Therefore, I have not forecasted any RMR contract costs for 2021.

Q. Can you please explain the forecast of the ISO-NE Administrative Charges shown on lines 7 and 8 of Schedule JDW-1 page 1?

A. Yes. Lines 7 and 8 include ISO-NE Administrative charges for Scheduling & Dispatch and NESCOE, respectively, and are derived in columns 7 and 8 on Schedule JDW-2. Line 7 on Schedule JDW-1, page 1, shows the 2022 forecast of charges to Liberty under Schedule 1, Scheduling and Load Dispatch Administrative schedules through Section IV.A of the ISO Tariff. The estimate is based on the ISO Schedule 1 rate of $0.19175 per kW-month effective January 1, 2022, multiplied by Liberty's forecasted monthly network load as shown in column 1 of Schedule JDW-2.

Line 8 on page 1 of Schedule JDW-1 shows the estimated 2021 NESCOE charges under Schedule 5 of Section IV.A of the ISO Tariff. I derived this amount by using the ISO Schedule 5 rate of $0.00736 per kW-month effective January 1, 2022, multiplied by Liberty's forecasted monthly network load as shown in column 1 of Schedule JDW-2.

Q. What is the sub-total of transmission expenses attributable to charges from the ISO-NE?

A. The sub-total of ISO-NE charges is $22,382,418, which is the sum of lines 3 through 8 on Schedule JDW-1, page 1.

Q. Have you estimated the charges to Liberty under Schedule 21 of the ISO Tariff?

A. Yes. Lines 1 and 2 of Schedule JDW-1 show the amount of forecasted charges from NEP pursuant to the LNS tariff. The total amount of estimated expenses is $6,619,714, which represents an increase of $535,570 in the total NEP estimated expenses to be incurred by Liberty in 2022 (see Schedule JDW-1, page 2, lines 1 and 2) as compared to 2021. As shown on Schedule JDW-4, column 2, I estimated the LNS expenses based on NEP's posted LNS charge of $36.07 per kW-year, divided by 12, and multiplied by Liberty's forecasted monthly network load as shown in column 1 of Schedule JDW-4. Load Dispatch Surcharge, Metering, transformation, specific distribution, and ancillary service charges are based on current rates and are assessed to Liberty based on a per meter and peak load basis, respectively. A maintenance service credit, as discussed previously, was also included in the estimate.

V. EXPLANATION OF PRIMARY CHANGE FROM LAST YEAR'S FORECASTED EXPENSES

Q. What is the primary cause of the estimated increase in Liberty's 2022 transmission expenses?

A. The estimated 2022 Liberty transmission and ISO-NE expenses of $29,002,132 represent an increase of $2,110,950 from the 2021 forecast of transmission expenses for Liberty.

The increase is mainly attributed to the increased cost of OATT Schedule 9 RNS Service costs. Since 2002 the transmission owners in New England have invested approximately $11.7 billion in transmission projects that were reviewed and approved in the ISO transmission investment process. The transmission owners are forecasting an investment of an additional $1 billion over the next ten years.

VI. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

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Schedules

Schedule JDW-1	Summary of Transmission Expenses Estimated for 2022
Schedule JDW-2	Summary of ISO Tariff Section II Charges Estimated for 2022
Schedule JDW-3	Summary of System Restoration and Reactive Supply Charges Estimated for 2022
Schedule JDW-4	Summary of New England Power Schedule No. 21 Charges Estimated for 2022

Summary of Transmission Expenses
Estimated For the Year 2022

	ISO-NE Tariff Schedule 21 NEP LNS Tariff Charges		
1	Local Network Service (Monthly Demand Charges)	$5,410,449	
2	Other NEP Charges	1,209,265	
	Subtotal NEP Charges		$6,619,714
	ISO-NE OATT Tariff Section II Charges		
3	OATT Schedule 9 - Regional Network Service Charges	$21,416,682	
4	OATT Schedule 1 - Scheduling, System Control & Dispatch	280,284	
5	OATT Schedule 16 - System Restoration and Planning Service	210,598	
6	OATT Schedule 2 - Reactive Supply and Voltage Control Service	116,459	
	Subtotal ISO-NE Tariff Section II Charges		$22,024,023
	ISO-NE Tariff Section IV.A - Administrative Charges		
7	ISO-NE Schedule 1 - Scheduling & Dispatch Service	$345,147	
8	ISO-NE Schedule 5 - NESCOE Budget	13,248	
	Subtotal ISO-NE Tariff Section IV.A Charges		$358,395
9	**Subtotal of ISO-NE Tariff Charges**		$22,382,418
10	**Total Estimated Expenses Flowing Through Current Rates**		$29,002,132

Line 1 = JDW-4: Column (1), Line 13
Line 2 = JDW-4: Sum of Column (2) thru (6), Line 13
Line 3 = JDW-2, page 1: Column (2), Line 13
Line 4 = JDW-2, page 1: Column (3), Line 13
Line 5 = JDW-2, page 1: Column (5), Line 13
Line 6 = JDW-2, page 1: Column (6), Line 13
Line 7 = JDW-2, page 2: Column (2), Line 13
Line 8 = JDW-2, page 2: Column (3), Line 13
Line 9 = Sum of Line 3 thru Line 8
Line 10 = Sum of Line 1 thru Line 8

Summary of Estimated Transmission Expenses
2020 vs. 2021 Filing Years

		1 **2021 Retail Filing**	2 **2022 Estimate**	3 **Yr/Yr Incr/(Decr)**
	ISO-NE Tariff Schedule 21 NEP LNS Tariff Charges			
1	Local Network Service (Monthly Demand Charges)	$ 4,894,564	$ 5,410,449	$ 515,885
2	Other NEP Charges	1,189,581	1,209,265	19,684
	Subtotal	$ 6,084,144	$ 6,619,714	$ 535,570
	ISO-NE OATT Tariff Section II Charges			
3	OATT Schedule 9 - Regional Network Service Charges	$ 19,884,162	$ 21,416,682	$ 1,532,520
4	OATT Schedule 1 - Scheduling, System Control & Dispatch	257,564	280,284	22,721
5	OATT Schedule 16 - System Restoration and Planning Service	182,049	210,598	28,549
6	OATT Schedule 2 - Reactive Supply and Voltage Control Service	128,922	116,459	(12,463)
	Subtotal	$ 20,452,697	$ 22,024,023	$ 1,571,326
	ISO-NE Tariff Section IV.A - Administrative Charges			
7	ISO-NE Schedule 1 - Scheduling & Dispatch Service	$ 343,255	$ 345,147	$ 1,892
8	ISO-NE Schedule 5 - NESCOE Budget	11,086	13,248	2,162
	Subtotal	$ 354,341	$ 358,395	$ 4,054
9	**Subtotal of ISO-NE Tariff Charges**	$ 20,807,038	$ 22,382,418	$ 1,575,380
10	**Total Estimated Expenses**	$ 26,891,183	$ 29,002,132	$ 2,110,950

Summary of ISO-NE Tariff Section II Charges
Estimated For the Year 2022

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
		Monthly PTF kW Load	OATT Schedule 9 - Regional Network Service Charges	OATT Schedule 1 - Scheduling, System Control & Dispatch	OATT Schedule 16 - System Restoration and Planning Service	OATT Schedule 2 - Reactive Supply and Voltage Control Service	ISO-NE OATT Tariff Section II Charges	ISO-NE Schedule 1 - Scheduling & Dispatch Service	ISO-NE Schedule 5 - NESCOE Budget	Total ISO-NE Transmission Charges
1	January	141,704	1,686,032	22,065	16,579	9,168	1,733,845	27,172	1,043	1,762,060
2	February	140,232	1,668,518	21,836	16,407	9,073	1,715,834	26,889	1,032	1,743,756
3	March	135,781	1,615,559	21,143	15,886	8,785	1,661,373	26,036	999	1,688,409
4	April	117,699	1,400,414	18,327	13,771	7,615	1,440,128	22,569	866	1,463,563
5	May	157,085	1,869,040	24,460	18,379	10,163	1,922,042	30,121	1,156	1,953,320
6	June	196,726	2,340,699	30,633	23,017	12,728	2,407,077	37,722	1,448	2,446,247
7	July	177,992	2,117,797	27,716	20,825	11,516	2,177,854	34,130	1,310	2,213,294
8	August	193,402	2,301,149	30,116	22,628	12,513	2,366,406	37,085	1,423	2,404,914
9	September	153,281	1,823,779	23,868	17,934	9,917	1,875,498	29,392	1,128	1,906,018
10	October	125,795	1,496,743	19,588	14,718	8,139	1,539,188	24,121	926	1,564,235
11	November	127,608	1,518,314	19,870	14,930	8,256	1,561,371	24,469	939	1,586,779
12	December	132,678	1,578,639	20,660	15,523	8,584	1,623,406	25,441	977	1,649,824
13	**12-Mo Total**		**$21,416,682**	**$280,284**	**$210,598**	**$116,459**	**$22,024,023**	**$345,147**	**$13,248**	**$22,382,418**

Line 1-12: Column (1) = 2021 Monthly Coincident Network Load of LU				
Line 1-12: Column (2) = January 1, 2022 OATT Schedule 9 RNS Rate * Column (1) / 12	2022 RNS Rate=	**$**	**142.78**	/kW-YR
Line 1-12: Column (3) = Current OATT Schedule 1 Rate * Column (1) / 12	Rate =	**$**	**1.86858**	/kW-YR
Line 1-12: Column (4) = 0 [No Reliability Must Run Contracts are currently in effect for New Hampshire				
Line 1-12: Column (4) = JDW-3, Line 8 * Column (1)	Rate =	**$**	**0.11700**	/kW-Month
Line 1-12: Column (5) = JDW-3, Line 4 * Column (1)	Rate =	**$**	**0.06470**	/kW-Month
Line 1-12: Column (6) = Sum of Columns (2) thru (5)				
Line 1-12: Column (7) = Current ISO-NE Schedule 1 Rate * Column (1)	Rate =	$	0.19175	kW-month
Line 1-12: Column (8) = Current ISO-NE Schedule 5 Rate * Column (1)	Rate =	$	0.00736	kW-month
Line 1-12: Column (9) = Sum of Columns (6) thru (8)				
Line 13 = Sum of Line 1 thru Line 12				

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Summary of Reactive Power & Black Start Costs
Estimated For the Year 2022

Section I: Development of ISO-NE Schedule 2 Costs

1	Granite Total ISO-NE Schedule 2 Costs	$152,732
2	2021 Granite Peak Load (KW)	196,726
3	Estimated Rate / KW-Yr	$0.7764
4	Estimated Rate / KW-Mo	$0.0647

Section II: Development of ISO-NE Schedle 16 Costs

5	GraniteTotal ISO-NE Schedule 17 Settlement Costs	$276,305
6	2021 Granite Peak Load (KW)	196,726
7	Estimated Rate / KW-Yr	$1.4045
8	Estimated Rate / KW-Mo	$0.1170

Line 1 = Granite ISO-NE Schedule 2 costs for the 12 months ending December 2021
Line 2 = Granite Peak Load in 2021
Line 3 = Line 1 / Line 2
Line 4 = Line 3 / 12
Line 5 = ISO Schedule 16 Settlement Reports for the 12 months ending December 2021
Line 6 = Line 2
Line 7 = Line 5 / Line 6
Line 8 = Line 7 / 12

Summary of New England Power - Schedule No. 21 Charges
Estimated For the Year 2022

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	
	Period	Monthly Regional Network Load	Local Network Service Charge	Load Dispatch Surcharge	Specific Distribution Surcharge	Transformer Surcharge	Meter Surcharge	Maintenance Service Credit	NEP Costs
1	January	141,704	425,939	3,806	15,609	82,104	1,111	(2,081)	526,488
2	February	140,232	421,514	3,766	15,609	82,104	1,111	(2,081)	522,024
3	March	135,781	408,135	3,647	15,609	82,104	1,111	(2,081)	508,525
4	April	117,699	353,784	3,161	15,609	82,104	1,111	(2,081)	453,688
5	May	157,085	472,171	4,219	15,609	82,104	1,111	(2,081)	573,134
6	June	196,726	591,326	5,284	15,609	82,104	1,111	(2,081)	693,353
7	July	177,992	535,014	4,781	15,609	82,104	1,111	(2,081)	636,538
8	August	193,402	581,334	5,194	15,609	82,104	1,111	(2,081)	683,272
9	September	153,281	460,737	4,117	15,609	82,104	1,111	(2,081)	561,597
10	October	125,795	378,119	3,379	15,609	82,104	1,111	(2,081)	478,241
11	November	127,608	383,568	3,427	15,609	82,104	1,111	(2,081)	483,739
12	December	132,678	398,808	3,564	15,609	82,104	1,111	(2,081)	499,115
13	**12- Mo Total**		**$5,410,449**	**$48,345**	**$187,312**	**$985,249**	**$13,332**	**-$24,972**	**$6,619,714**

Line 1-12: Column (1) = 2021 Monthly Coincident Network Load of LU
Line 1-12: Column (2) = January 1, 2022 Schedule 21-NEP LNS Rate * Column (1) / 12 — 2022 LNS Rate= $ **36.07** /kW-YR
Line 1-12: Column (3) = January 1, 2022 Schedule 21-NEP Load DispatchSurcharge Rate * Column (1) / 12 — 2022 LDS Rate= $ **0.3223** /kW-YR
Line 1-12: Column (4) = 22,299 kW & $0.70 per NEP Tariff as of June 1, 2021
Line 1-12: Column (5) = 195,486 kW & $0.42 per NEP Tariff as of June 1, 2021
Line 1-12: Column (6) = 18 meters * $61.72 per meter per NEP Tariff as of June 1, 2021
Line 1-12: Column (7) Per the Integrated Facilities Supplement dated July 3, 2012 between NEP and Granite State
Line 1-12: Column (8) = Sum of Columns (2) through (7)

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Docket No. DE 22-XXX

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty

Annual Retail Rate Adjustments

DIRECT TESTIMONY

OF

HEATHER TEBBETTS

AND

ADAM HALL

March 22, 2022

Liberty™

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I. INTRODUCTION

Q. Ms. Tebbetts, please state your full name, business address, position, and responsibilities.

A. My name is Heather M. Tebbetts and my business address is 9 Lowell Road, Salem, New Hampshire. I am the Manager of Rates and Regulatory Affairs for Liberty Utilities Service Corp. ("LUSC") where my duties include providing rate-related services for Liberty Utilities (Granite State Electric) Corp. ("Granite State" or "the Company").

Q. Please describe your educational background and training.

A. I graduated from Franklin Pierce University in 2004 with a Bachelor of Science degree in Finance. I received a Master of Business Administration from Southern New Hampshire University in 2007.

Q. Please describe your professional background.

A. I joined LUSC in October 2014. Prior to my employment at LUSC, I was employed by Public Service Company of New Hampshire ("PSNH") as a Senior Analyst in NH Revenue Requirements from 2010 to 2014. Prior to my position in NH Revenue Requirements, I was a Staff Accountant in PSNH's Property Tax group from 2007 to 2010 and a Customer Service Representative III in PSNH's Customer Service Department from 2004 to 2007.

Q. Have you previously testified before the Commission?

A. Yes, I have testified on numerous occasions before the Commission.

<u>Adam Hall</u>

Q. Mr. Hall, please state your full name, business address, position, and responsibilities.

A. My name is Adam M. Hall. My business address is 15 Buttrick Road, Londonderry, New Hampshire. I am an Analyst in the Rates and Regulatory Affairs department for LUSC where my responsibilities include providing rate-related services for Granite State.

Q. Please describe your educational and professional background.

A. I graduated from Siena College in 2014 with a Bachelor of Science in Finance. I also received a Master of Business Administration from Franklin Pierce University in 2016. I joined Liberty as an Analyst, Rates and Regulatory Affairs in January 2019.

Q. Have you previously testified in regulatory proceedings before the Commission?

A. Yes, on multiple occasions.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your joint testimony?

A. This testimony presents Granite State's proposed rates for stranded costs and transmission costs for effect May 1, 2022, in accordance with the Company's reconciliation and adjustment provisions in its tariff and the Company's Amended Restructuring Settlement as approved in Docket No. DR 98-012. Included in the proposed rates are the 12-month reconciliation for the period May 1, 2021, through April 30, 2022, of: 1) transmission costs, 2) stranded cost charges, 3) the Regional Greenhouse Gas Initiative ("RGGI") auction proceeds refund, 4) the net metering lost revenue adjustment mechanism ("LRAM"), and 5) GSE's municipal property tax expenses as compared to base distribution rates. The Company is also proposing its first request for recovery of the rate adjustments related to the Company's Property Tax Adjustment Mechanism ("PTAM") through the Company's transmission charge.

Q. Please summarize the approach for calculating the retail rates.

A. At a high level, for each rate component the Company calculates average rates using forecasted costs for the rate year. For the transmission charge, the forecasted costs are based on ISO New England Regional Network System ("RNS") charges and National Grid Local Network System ("LNS") charges. For the stranded cost charge, the forecasted costs are Contract Termination Charge ("CTC") credits. In addition, a calculation of the prior period (over)/under collection of revenues and expenses, including interest, is added to the total forecasted costs for each mechanism. The total forecasted costs and prior period over/under recovery balance are then divided by total forecasted kilowatt-hour (kWh) sales for the period of May 1, 2022, through April 30, 2023, to derive the average rate for each component. This method is generally consistent with past methods and practices.

Q. Please explain the 12-month reconciliation period and what data is used in the analysis.

A. The 12-month reconciliation for the period May 1, 2021, through April 30, 2022, includes actual revenues and expenses for May 2021 through February 2022 and forecasted revenue and expenses for March through April 2022 because actual results are not available at the time the filing is prepared. In the Company's next annual reconciliation, the beginning over/under recovery balance includes actuals for those forecasted months.

Q. Please summarize the results of the adjustments and reconciliations which Granite State proposes to implement in 2022.

A. The Company proposes to implement the following adjustments to its rates beginning May 1, 2022, for usage on and after that date. Schedule HMT/AMH-1 presents the proposed stranded cost and the transmission rates. The table below illustrates the current and proposed rates:

Table 1: Rates

Average charge ($ / kWh)	Current	Proposed	Increase (Decrease)
Stranded Cost Charge	$ (0.00080)	$ (0.00050)	$ 0.00030
Stranded Cost Adjustment Factor	$ 0.00000	$ (0.00001)	$ (0.00001)
Transmission Charge	$ 0.03490	$ 0.03161	$ (0.00329)
Transmission Service Cost Adjustment	$ 0.00376	$ 0.00100	$ (0.00276)
RGGI Auction Proceeds Refund	$ (0.00211)	$ (0.00391)	$ (0.00180)
LRAM	$ 0.00048	N/A	N/A
PTAM	$ 0.00000	$ 0.00036	$ 0.00036
Total	$ 0.03623	$ 0.02854	$ (0.00769)

III. STRANDED COST CHARGE AND THE STRANDED COST ADJUSTMENT FACTOR

Q. What is the Stranded Cost Charge?

A. Granite State's Stranded Cost Charge is the sum of two components. The first is a uniform charge per kilowatt-hour ("kWh") that the Company charges all customers which reflects the CTC assessed by New England Power Company ("NEP") for 2022.

The second component is the Stranded Cost Adjustment Factor ("SCAF"), which is specific to each rate class.

Q. What is NEP?

A. In 1996, New Hampshire implemented electric retail choice for all customers with the passage of the restructuring statute, RSA 374-F, which included Granite State divesting itself of its generation assets. At that time, the CTC was established to allow for the recovery of costs associated with stranded generation assets that had been owned by the Company's former affiliate, NEP, and operated on behalf of Granite State's customers.[1] Specific costs include decommissioning expense and purchase power costs, and were expected to have been recovered by 2020. However, a handful of cost remain outstanding.

Q. What are the components of the CTC?

A. There are two components, fixed and variable costs. The fixed costs related to the divestiture of the generation and are no longer being charged to Granite State as the obligation ended in 2011. The variable costs relate to the bankruptcy of USGen New England, Inc., the entity that purchased all of NEP's non-nuclear generating assets. The settlement in the bankruptcy provided that Granite State receive an allocation of the claim proceeds received by NEP annually to pay down all of the remaining NEP power contract buyout payments.

1 DR 98-012 Settlement Agreement https://www.puc.nh.gov/Regulatory/Orders/1998ords/23041e.html

Q. What rate is the Company proposing for the CTC and how was it determined?

A. The proposed CTC of ($0.00050)/kWh was calculated by NEP in Docket No. DE 22-003 by reconciling actual revenues and expenses for the prior period of October 2020 through September 2021. The rate is a negative, a credit, due to the allocation of the claim proceeds as noted above.

Q. What rate is the Company proposing for the SCAF and how was it determined?

A. The Company is proposing a load weighted SCAF rate of ($0.00001)/kWh. The SCAF is the (over)/under collection of the CTC charge. GSE over collected in 2021 a total of $11,933 and as such the adjustment factor is a refund to customers as shown in Schedule HMT/AMH-2, page 1.

Q. What does it meant that the SCAF is "load weighted"?

A. The adjustment factor calculation provides that each rate class receives a portion of the charges or credits based on the load of that class.

IV. TRANSMISSION CHARGE

Q. Please describe the Company's Transmission Charge ("TC").

A. The Company recovers its transmission-related expenses pursuant to the TC, which allows the Company to recover costs billed to it by ISO-New England and NEP through the ISO-New England Inc. Transmission, Markets, and Services Tariff ("ISO Tariff"). The TC charge is comprised of two components: 1) a component for base transmission costs for the prospective period; and 2) a component for the reconciliation of transmission revenue and expense for the previous period.

Q. What is the forecast of 2022 transmission costs?

A. As discussed in the testimony of John D. Warshaw, the Company's 2022 transmission costs are estimated to be $29,002,132 as shown in Schedule HMT/AMH-3, page 1, line 1. This forecast of transmission expense yields an average rate of $0.03161 per kWh, as compared to the currently effective average transmission rate of $0.03057 per kWh, exclusive of the reconciliation component. Based on these estimates, the Company is proposing new base transmission rates effective May 1, 2022, to recover the projected transmission costs to be incurred in the prospective period.

Q. Does the Company charge a flat transmission rate or a load-weighted rate?

A. The Company charges a load-weighted transmission rate to its customers to account for the fact that customer class loads differ greatly. By charging load-weighted rates, the Company is following the cost causation principle that the rate classes causing the most costs should be allocated the most costs. The table below provides a snapshot of the load weighted rates proposed for May 1, 2022.

Table 2: Transmission Rates ($/kWh)

D	D-10	G-1	G-2	G-3	Streetlights	T	V
$0.03890	$0.02593	$0.02747	$0.02784	$0.03269	$0.02183	$0.02870	$0.03258

Q. How were the rates calculated?

A. The rate class-specific transmission rates were calculated by dividing the allocated transmission expense estimate for each rate class for the May 1, 2022, through April 30, 2023, time period by the forecasted kWh sales for each rate class for the same time period as shown in Schedule HMT/AMH-3, page 1.

Q. How was the reconciliation component of the TC charge derived?

A. The reconciliation component of the TC recovers under-recoveries of transmission costs or refunds over-recoveries of transmission costs, along with associated interest at the prime rate. This component of the TC charge was calculated by totaling the projected under-collection of transmission expense of $915,216 as of April 30, 2022, as shown on Schedule HMT/AMH-3, page 3 plus the working capital of ($1,720) as shown on Schedule HMT/AMH-3, page 5 for a total of $913,496. That amount is then divided by the forecasted kWh sales for the period of May 1, 2022, through April 30, 2023, of 917,255,198 for a reconciliation rate of $0.00100 per kWh to be added to the weighted transmission rates on Schedule HMT/AMH-1, page 1, column (d).

Q. Please describe the working capital calculation included in the filing.

A. The Settlement Agreement in Docket No. DE 19-064 provided, in part, that the Company may recover cash working capital on transmission costs through the transmission cost adjustment mechanism included in the Company's Annual Retail Rate Adjustment filing. In accordance with that settlement, the Company has included a transmission cash working capital amount in the calculation of its proposed transmission rates in Schedule HMT/AMH-3, pages 5 through 7.

Q. What is the total amount of transmission working capital included in this filing?

A. The total working capital included in the TC charge is ($1,720) as shown on Schedule HMT/AMH-3, page 5. The expense lag is calculated by summing all invoices for 2021 and multiplying the period of days between when the invoice was received and when it was paid, to determine the number of days of cost as shown on Schedule HMT/AMH-3, page 6. The days of cost is then divided by 365 days in the year to determine the invoice payment lag. The revenue lag is calculated by summing three components: 1) the Service Lag of 15.21 days; 2) the Collection Lag of 42.82 days; and 3) the Billing Lag of 2.59 days. The Service Lag and Billing Lag were agreed upon in the Settlement Agreement in Docket No. DE 19-064. The Collection Lag is calculated by summing the total customer receivables for 2021 of $12,410,252 and dividing that amount by the total daily average revenues of $289,808. The daily revenues are calculated by the monthly sales divided by the number of days in that month and averaged for the twelve months. The detailed calculation of the revenue lag is shown on Schedule HMT/AMH-3, page 7.

V. REGIONAL GREENHOUSE GAS INITIATIVE AUCTION PROCEEDS

Q. How does the Company propose to refund Regional Greenhous Gas Initiative (RGGI) auction proceeds to delivery service customers?

A. Consistent with Order No. 25,664 (May 9, 2014) in Docket No. DE 14-048, the Company will credit the RGGI rebate amount it receives from the allocation on a per kWh basis through its retail rate reconciliation mechanism that is adjusted on an annual basis. The Company has included a credit of ($0.00391) per kWh for RGGI auction proceeds in its transmission service charge for 2022, as shown on Schedule HMT/AMH-4. This credit of ($0.00391) per kWh is comprised of the estimated RGGI auction proceeds for May 2022 through April 2023 of ($2,457,046) and the reconciliation component through April 2022 of ($1,130,067). The total of ($3,587,112) is then divided by the estimated sales of 917,255,198 kWh to calculate the RGGI credit of ($0.00391) per kWh, as compared to the current rate of ($0.00211) per kWh.

VI. LRAM

Q. What is the LRAM?

A. Consistent with RSA 362-A362A:9, VII and Order No. 26,029 (June 23, 2017) in Docket No. DE 16-576, the Commission authorized utilities to collect lost revenues associated with net metering customers. The LRAM is included in the TC as an annual reconciliation. Given that Granite State's decoupling mechanism took effect on July 1, 2021, the Company is only requesting LRAM for the first six months of 2021 as the decoupling mechanism has taken the place of the LRAM for collecting lost distribution revenues for net metering customers.

Q. Will the Company be including its LRAM costs in this filing?

A. The Company is awaiting the avoided cost calculation from the Department of Energy ("DOE") to determine how much it will pay its net metering customers who have banked 600 kWh or greater per Puc 908.04. Once that information is available from DOE, the Company will file a supplemental schedule providing the total net metering lost revenue to be recovered.

VII. PTAM

Q. What is the purpose of the PTAM?

A. The PTAM is a mechanism provided by RSA 72:8-e that authorizes the Company to reconcile its actual property tax expense each New Hampshire property tax year (April 1 through March 31) with the revenue currently collected through customer rates and make annual adjustments to distribution rates accordingly.

Q. How is the PTAM to be implemented?

A. RSA 72:8-e directed the Commission to "establish a rate recovery mechanism for any public utility owning property that meets the definition of utility company assets under RSA 72:8-d, I." The mechanism will "adjust annually to recover all property taxes paid by each such utility on such utility company assets …." The Company's proposed mechanism is to calculate the difference between the amount of property taxes included in distribution rates and the total amount of municipal property tax bills for the relevant property tax year. The Company proposes to recover that amount through annual adjustments to the GSE Transmission Charge.

Q. What period of time is covered by the PTAM adjustment proposed in your testimony?

A. The PTAM adjustment proposed covers the period April 1, 2020, the beginning date authorized by RSA 72:8-d, through March 31, 2021 ("Property Tax Year 2020") and April 1, 2021, through March 31, 2022 ("Property Tax Year 2021").

Q. What is the history of the PTAM filing for GSE?

A. In Docket No. DE 21-040, the Company filed a petition for approval of an annual property tax mechanism to recover or refund the Company's total property tax expense. RSA 72:8-b was passed in 2019 and allowed for the Commission to approve a mechanism by which the utilities could collect its property taxes annually through a reconciling mechanism, rather than waiting for its next rate case to set the level of funding through rates for property taxes. During the period that DE 21-040 was open, EnergyNorth Natural Gas ("ENNG") was involved in Docket No. DG 20-105. The Settlement Agreement in DG 20-105 provided that ENNG would be authorized to implement a property tax mechanism consistent with RSA 72:8. Given the approval of the agreement, GSE withdrew its petition in DE 21-040. The Company filed a new petition in Docket No. DG 21-128 to include the property tax recovery or refund in distribution rates. In Order No. 26,540 (November 1, 2021) and Order No. 26,554 (December 9, 2021), the Commission approved the recovery of the PTAM methodology and rate and that the Local Distribution Adjustment Clause ("LDAC") is the more appropriate recovery mechanism to recover the PTAM.

At this time, the Company is looking to implement a similar methodology and is requesting that the approved methodology in DG 21-128 be included in the transmission portion of the retail rates because of the annual reconciling nature of the mechanism.

Q. Please explain how the property tax expense in 2019 base distribution rates was derived.

A. The amount of property tax expense in base distribution rates started with the property taxes paid during GSE's last test year, 2018, of $4,673,568. A proforma adjustment was made for known and measurable adjustments for the 2019 property tax year of $124,983. The proforma property tax amount in 2019 was derived by using the first installment of 2019 property tax invoices and multiplying that amount by two to derive and estimate of the 2019 property tax year amount. The incremental amount above what was paid in 2018 was $124,983. Therefore, the total amount in base distribution rates as approved in the GSE distribution rate case in DE 19-064 is an estimated 2019 property tax year amount of $4,798,551.

Q. Were there any adjustments made to property amount included in the Company's base distribution rate set in the last rate case?

A. Yes. The 2019 property taxes paid to the state of New Hampshire in the amount of $962,839 was included in the base distribution rate. Per Section 6.2 in the Settlement Agreement in DG 20-105, the methodology agreed to by the Company does not include state property taxes from the annual property tax reconciliation. After removing the state property tax amount, the adjusted 2019 annual property tax expense in base distribution rates was $3,835,712.

Q. Did the Company recover property taxes through base distribution rates in 2020?

A. Yes. The following property taxes adjustments were calculated and recovered in in 2020:

1) as of January 1, 2020, the Company recovered property taxes associated with capital placed in service in 2019 as part of the Reliability Enhancement Program ("REP") filed in Docket No. DE 20-036 in the amount of ($19,378), a credit,

2) as of January 1, 2020, the Company recovered property taxes associated with capital placed in service in 2020 as part of the REP filed in Docket No. DE 21-049 in the amount of $26,743; and

3) as of July 1, 2020, the Company recovered nine-months of property taxes associated with capital placed in service in 2019 as part of the Step Adjustment filed in Docket No. DE 19-064 in the amount of $198,142.

The total amount of additional property tax expense recovered through 2020 base distribution rates is $205,507. Adding this amount to the adjusted 2019 property tax expense results in a 2020 property tax expense in base distribution rates of $4,041,219. This is used as the basis for comparing 2020 actual property tax expenses.

Q. Did the Company recover property taxes through base distribution rates in 2021?

A. Yes. The following property taxes adjustments were calculated and recovered in in 2021:

1) as of July 1, 2020, the Company recovered three-months of property taxes associated with capital placed in service in 2019 as part of the Step Adjustment filed in Docket No. DE 19-064 in the amount of $66,047;

2) as of July 1, 2021, the Company recovered nine-months of property taxes associated with capital placed in service in 2020 as part of the Step Adjustment filed in Docket No. DE 19-064 in the amount of $220,911; and

3) as of November 1, 2021, the Company recovered five-months of property taxes associated with capital placed in service in 2020 as part of the Step Adjustment filed in Docket No. DE 19-064 in the amount of $7,170.

The total amount of additional property tax recovered through 2021 base distribution rates is $294,128. Adding this amount to the adjusted 2020 property tax expense results in a 2021 property tax expense in base distribution rates of $4,335,347. This is used as the basis for comparing 2021 actual property tax expenses.

Q. Is the Company's PTAM consistent with such mechanisms previously approved by the Commission for other utilities in New Hampshire?

A. Yes, the PTAM proposed in this filing is effectively the same mechanism as those approved by the Commission for Unitil Energy Systems, Inc., in Order No. 26,500 (July 29, 2021) and for Eversource Energy in Order No. 26,433 (December 15, 2020), both electric distribution utilities with mechanisms that collect increases in property taxes through a reconciling component of customer rates. GSE's proposal here is also the same as the LDAC-based mechanism approved for the Company's natural gas affiliate in Order No. 26,505 (July 30, 2021); *see* Order No. 26,554 (December 9, 2021) (approving the first implementation of the PTAM for EnergyNorth).

Q. Please describe the results of your analysis.

A. In Order No. 26,554, the Commission approved ENNG's method of calculating the amount of municipal property taxes to be included in distribution rates. Table 3 below summarizes the analysis by year.

Table 3: Property tax variance, 2020–2021

Year	Amount in Base Distribution Rates	Actual Property Tax Expense	(Over)/Under Recovery
2020	$4,041,219	$4,514,178	$472,959
2021	$4,335,347	$4,193,261	($142,086)
Total	$8,376,566	$8,707,439	$330,873

The Company is proposing to recover in this proceeding the aggregation of years 2020 and 2021, or $330,873. This calculation is provided in Schedule HMT/AMH-5, page 2. Details of the property tax invoice amounts by municipality and by parcel totaling the $8,707,439 are included in Schedule HMT/AMH-5, pages 3 and 4.

Q. What is the proposed PTAM rate and how was it calculated?

A. The proposed PTAM rate is $0.00036 per kWh and was calculated by summing the property tax invoices from 2020 and 2021, summing the total property taxes in rates for 2020 and 2021, and subtracting the difference for an under recovery of $330,873. The total under recovery was divided by the forecasted kWh for the period of May 1, 2022, through April 30, 2023, of 917,255,198.

Q. How and when will the Company update the PTAM?

A. A reconciliation of the PTAM will occur each year as part of the annual retail rates filing. The PTAM rate, or factor, will adjust to reconcile the actual revenue received during the prior year and to take into account changes to property taxes that occurred since the prior adjustment.

VIII. TARIFF CHANGE

Q. Does the Company propose new tariff language to implement the PTAM?

A. Yes. The Company is proposing new language in the Transmission Charge section of the tariff describing: 1) the PTAM as a new component of the Transmission Charge and how the annual adjustment is calculated; 2) the reconciliation process; and 3) the procedure for implementing the annual adjustments. This proposed language is similar to what the Commission approved for EnergyNorth in Order No. 26,505.

The proposed tariff pages to achieve these changes, both redlined and clean, accompany our testimony as Schedule HMT/AMH-7.

IX. EFFECTIVE DATE AND RATE IMPACTS

Q. How and when is the Company proposing that these rate changes be implemented?

A. The Company is requesting rates effective May 1, 2022.

Q. Has the Company determined the impact of the proposed Retail Rates changes on a typical residential customer's monthly bill?

A. Yes. As shown in Schedule HMT/AMH-6, the monthly bill impact for a typical Residential customer using a total of 650 kilowatt hours is a decrease of ($0.26)/kWh or 0.017 percent.

Q. When does the Company required rates to be approved by?

A. The Company is requesting Commission approval by April 26, 2022, to allow time for rates to be implemented in the Company's billing system for effect on May 1, 2022.

X. <u>CONCLUSION</u>

Q. Does this conclude your testimony?

A. Yes, it does.

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Summary of Proposed Rates For Stranded Cost and Transmission $/kWh

1	Rate Class	Stranded Cost Charge	Stranded Cost Adjustment Factor	Net Stranded Cost Charge	Transmission Charge	Transmission Service Cost Adjustment	RGGI Auction Proceeds Refund	Property Tax Adjustment Mechanism	Net Transmission Charge
2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
3		DE 22-003	HMT/AMH-2 P1	(a) + (b)	HMT/AMH-3 P1	HMT/AMH-3 P4	HMT/AMH-4	HMT/AMH-5	(d) + (e) + (f) + (g)
4	**D**	($0.00050)	($0.00001)	**($0.00051)**	$0.03890	$0.00100	($0.00391)	$0.00036	**$0.03635**
5	**D-10**	($0.00050)	($0.00001)	**($0.00051)**	$0.02593	$0.00100	($0.00391)	$0.00036	**$0.02338**
6	**T**	($0.00050)	($0.00001)	**($0.00051)**	$0.02870	$0.00100	($0.00391)	$0.00036	**$0.02615**
7	**G-1**	($0.00050)	($0.00001)	**($0.00051)**	$0.02747	$0.00100	($0.00391)	$0.00036	**$0.02492**
8	**G-2**	($0.00050)	($0.00001)	**($0.00051)**	$0.02784	$0.00100	($0.00391)	$0.00036	**$0.02529**
9	**G-3**	($0.00050)	($0.00001)	**($0.00051)**	$0.03269	$0.00100	($0.00391)	$0.00036	**$0.03014**
10	**V**	($0.00050)	($0.00001)	**($0.00051)**	$0.03258	$0.00100	($0.00391)	$0.00036	**$0.03003**
11	**Streetlights**	($0.00050)	($0.00002)	**($0.00052)**	$0.02183	$0.00100	($0.00391)	$0.00036	**$0.01928**

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Calculation of Stranded Cost Adjustment Factor
Effective May 1, 2022 - April 30, 2023

1	Rate Class		Total (Over)/Under Collection	Total Period Forecasted kWh		Stranded Cost Adj. Factor
2			(a)	(b)		(c)
3	**D**	$	(3,554)	290,426,993	$	(0.00001)
4	**D-10**	$	(69)	5,814,620	$	(0.00001)
5	**T**	$	(181)	12,802,816	$	(0.00001)
6	**G-1**	$	(5,057)	373,287,350	$	(0.00001)
7	**G-2**	$	(1,884)	147,982,386	$	(0.00001)
8	**G-3**	$	(1,131)	83,792,046	$	(0.00001)
9	**V**	$	(4)	282,027	$	(0.00001)
10	**M- Streetlights**	$	(53)	2,866,961	$	(0.00002)
11		$	(11,933)	917,255,198	$	(0.00001)

(a) Schedules HMT/AMH-2 Pages 3 and 4
(b) Company forecast
(c) Column (a) / Column (b), truncated after 5 decimal places

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Stranded Cost Reconciliation Summary
All Rate Classes
May 2021 - April 2022

	1	Month	(Over)/Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/Under	(Over)/Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Cumulative Interest
	2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	3	May-21	($17,899)	($47,659)	($56,325)	($8,666)	($26,566)	($22,232)	3.25%	($60)	($60)
	4	Jun-21	($26,626)	($62,194)	($50,081)	$12,112	($14,513)	($20,569)	3.25%	($56)	($116)
	5	Jul-21	($14,569)	($68,886)	($62,246)	$6,641	($7,928)	($11,249)	3.25%	($30)	($146)
	6	Aug-21	($7,959)	($66,808)	($68,894)	($2,086)	($10,045)	($9,002)	3.25%	($24)	($171)
	7	Sep-21	($10,069)	($67,555)	($66,812)	$743	($9,326)	($9,698)	3.25%	($26)	($197)
	8	Oct-21	($9,352)	($53,981)	($67,557)	($13,576)	($22,929)	($16,141)	3.25%	($44)	($241)
	9	Nov-21	($22,972)	($51,299)	($53,981)	($2,682)	($25,654)	($24,313)	3.25%	($66)	($307)
	10	Dec-21	($25,720)	($59,181)	($51,299)	$7,882	($17,838)	($21,779)	3.25%	($59)	($366)
	11	Jan-22	($17,897)	($62,638)	($59,182)	$3,456	($14,441)	($16,169)	3.25%	($44)	($409)
	12	Feb-22	($14,485)	($61,801)	($59,149)	$2,652	($11,833)	($13,159)	3.25%	($36)	($445)
*	13	Mar-22	($11,868)	($60,425)	($60,425)	$0	($11,868)	($11,868)	3.25%	($32)	($477)
*	14	Apr-22	($11,900)	($55,133)	($55,133)	$0	($11,900)	($11,900)	3.25%	($32)	($509)
	15			($717,561)	($711,085)						
	16	**Projected Cumulative (Over)/Under Collection of Stranded Cost Charge:**						**($11,933)**			

(a) May-21 ties to the deferral account balance, all other months are Prior Month Column (e) + Prior Month Column (h)
(b) Company financials
(c) Company financials
(d) Column (c) - Column (b)
(e) Column (a) + Column (d)
(f) [Column (a) + Column (e)] ÷ 2
(g) Interest rate on customer deposits
(h) Column (f) x [Column (g) ÷ 12]
(i) Column (h) + Prior Month Column (i)
* Projected

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Stranded Cost Reconciliation
May 2021 - April 2022

1	Rate D	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (5,331)	$ (14,194)	$ (16,775)	$ (2,581)	$ (7,912)	$ (6,621)	3.25%	$ (18)	$ (18)
4	Jun-21	$ (7,930)	$ (18,523)	$ (14,915)	$ 3,607	$ (4,322)	$ (6,126)	3.25%	$ (17)	$ (35)
5	Jul-21	$ (4,339)	$ (20,516)	$ (18,538)	$ 1,978	$ (2,361)	$ (3,350)	3.25%	$ (9)	$ (44)
6	Aug-21	$ (2,370)	$ (19,897)	$ (20,518)	$ (621)	$ (2,992)	$ (2,681)	3.25%	$ (7)	$ (51)
7	Sep-21	$ (2,999)	$ (20,119)	$ (19,898)	$ 221	$ (2,778)	$ (2,888)	3.25%	$ (8)	$ (59)
8	Oct-21	$ (2,785)	$ (16,077)	$ (20,120)	$ (4,043)	$ (6,829)	$ (4,807)	3.25%	$ (13)	$ (72)
9	Nov-21	$ (6,842)	$ (15,278)	$ (16,077)	$ (799)	$ (7,640)	$ (7,241)	3.25%	$ (20)	$ (91)
10	Dec-21	$ (7,660)	$ (17,625)	$ (15,278)	$ 2,347	$ (5,312)	$ (6,486)	3.25%	$ (18)	$ (109)
11	Jan-22	$ (5,330)	$ (18,655)	$ (17,625)	$ 1,029	$ (4,301)	$ (4,815)	3.25%	$ (13)	$ (122)
12	Feb-22	$ (4,314)	$ (18,406)	$ (17,616)	$ 790	$ (3,524)	$ (3,919)	3.25%	$ (11)	$ (133)
* 13	Mar-22	$ (3,535)	$ (17,996)	$ (17,996)	$ -	$ (3,535)	$ (3,535)	3.25%	$ (10)	$ (142)
* 14	Apr-22	$ (3,544)	$ (16,420)	$ (16,420)	$ -	$ (3,544)	$ (3,544)	3.25%	$ (10)	$ (152)

15 **Cumulative (Over)/Under Collection of Stranded Cost $ (3,554)**

1	Rate T	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (272)	$ (724)	$ (856)	$ (132)	$ (404)	$ (338)	3.25%	$ (1)	$ (1)
4	Jun-21	$ (405)	$ (945)	$ (761)	$ 184	$ (221)	$ (313)	3.25%	$ (1)	$ (2)
5	Jul-21	$ (221)	$ (1,047)	$ (946)	$ 101	$ (120)	$ (171)	3.25%	$ (0)	$ (2)
6	Aug-21	$ (121)	$ (1,015)	$ (1,047)	$ (32)	$ (153)	$ (137)	3.25%	$ (0)	$ (3)
7	Sep-21	$ (153)	$ (1,027)	$ (1,015)	$ 11	$ (142)	$ (147)	3.25%	$ (0)	$ (3)
8	Oct-21	$ (142)	$ (820)	$ (1,027)	$ (206)	$ (348)	$ (245)	3.25%	$ (1)	$ (4)
9	Nov-21	$ (349)	$ (780)	$ (820)	$ (41)	$ (390)	$ (369)	3.25%	$ (1)	$ (5)
10	Dec-21	$ (391)	$ (899)	$ (780)	$ 120	$ (271)	$ (331)	3.25%	$ (1)	$ (6)
11	Jan-22	$ (272)	$ (952)	$ (899)	$ 53	$ (219)	$ (246)	3.25%	$ (1)	$ (6)
12	Feb-22	$ (220)	$ (939)	$ (899)	$ 40	$ (180)	$ (200)	3.25%	$ (1)	$ (7)
* 13	Mar-22	$ (180)	$ (918)	$ (918)	$ -	$ (180)	$ (180)	3.25%	$ (0)	$ (7)
* 14	Apr-22	$ (181)	$ (838)	$ (838)	$ -	$ (181)	$ (181)	3.25%	$ (0)	$ (8)

15 **Cumulative (Over)/Under Collection of Stranded Cost $ (181)**

1	Rate D-10	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (103)	$ (275)	$ (325)	$ (50)	$ (153)	$ (128)	3.25%	$ (0)	$ (0)
4	Jun-21	$ (154)	$ (359)	$ (289)	$ 70	$ (84)	$ (119)	3.25%	$ (0)	$ (1)
5	Jul-21	$ (84)	$ (397)	$ (359)	$ 38	$ (46)	$ (65)	3.25%	$ (0)	$ (1)
6	Aug-21	$ (46)	$ (385)	$ (397)	$ (12)	$ (58)	$ (52)	3.25%	$ (0)	$ (1)
7	Sep-21	$ (58)	$ (390)	$ (385)	$ 4	$ (54)	$ (56)	3.25%	$ (0)	$ (1)
8	Oct-21	$ (54)	$ (311)	$ (390)	$ (78)	$ (132)	$ (93)	3.25%	$ (0)	$ (1)
9	Nov-21	$ (132)	$ (296)	$ (311)	$ (15)	$ (148)	$ (140)	3.25%	$ (0)	$ (2)
10	Dec-21	$ (148)	$ (341)	$ (296)	$ 45	$ (103)	$ (126)	3.25%	$ (0)	$ (2)
11	Jan-22	$ (103)	$ (361)	$ (341)	$ 20	$ (83)	$ (93)	3.25%	$ (0)	$ (2)
12	Feb-22	$ (84)	$ (356)	$ (341)	$ 15	$ (68)	$ (76)	3.25%	$ (0)	$ (3)
* 13	Mar-22	$ (68)	$ (348)	$ (348)	$ -	$ (68)	$ (68)	3.25%	$ (0)	$ (3)
* 14	Apr-22	$ (69)	$ (318)	$ (318)	$ -	$ (69)	$ (69)	3.25%	$ (0)	$ (3)

15 **Cumulative (Over)/Under Collection of Stranded Cost $ (69)**

1	Rate M Streetlights	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (80)	$ (212)	$ (250)	$ (39)	$ (118)	$ (99)	3.25%	$ (0)	$ (0)
4	Jun-21	$ (118)	$ (277)	$ (223)	$ 54	$ (65)	$ (91)	3.25%	$ (0)	$ (1)
5	Jul-21	$ (65)	$ (306)	$ (277)	$ 30	$ (35)	$ (50)	3.25%	$ (0)	$ (1)
6	Aug-21	$ (35)	$ (297)	$ (306)	$ (9)	$ (45)	$ (40)	3.25%	$ (0)	$ (1)
7	Sep-21	$ (45)	$ (300)	$ (297)	$ 3	$ (41)	$ (43)	3.25%	$ (0)	$ (1)
8	Oct-21	$ (42)	$ (240)	$ (300)	$ (60)	$ (102)	$ (72)	3.25%	$ (0)	$ (1)
9	Nov-21	$ (102)	$ (228)	$ (240)	$ (12)	$ (114)	$ (108)	3.25%	$ (0)	$ (1)
10	Dec-21	$ (114)	$ (263)	$ (228)	$ 35	$ (79)	$ (97)	3.25%	$ (0)	$ (2)
11	Jan-22	$ (80)	$ (279)	$ (263)	$ 15	$ (64)	$ (72)	3.25%	$ (0)	$ (2)
12	Feb-22	$ (64)	$ (275)	$ (263)	$ 12	$ (53)	$ (59)	3.25%	$ (0)	$ (2)
* 13	Mar-22	$ (53)	$ (269)	$ (269)	$ -	$ (53)	$ (53)	3.25%	$ (0)	$ (2)
* 14	Apr-22	$ (53)	$ (245)	$ (245)	$ -	$ (53)	$ (53)	3.25%	$ (0)	$ (2)

15 **Cumulative (Over)/Under Collection of Stranded Cost $ (53)**

(a) May-21 ties to the deferral account balance, all other months are Prior Month Column (e) + Prior Month Column (h)
(b) Company billing system report; Includes adjustment factor
(c) Per Dockets DE 19-025 (May 19 - Dec 19) and DE 20-016 (Jan 20 - April 20)
(d) Expense (Column c) - Revenue (Column b)
(e) Column (a) + Column (d)
(f) [Column (a) + Column (e)] ÷ 2
(g) Interest rate
(h) Column (f) x [Column (g) ÷ 12]
(i) Column (h) + Prior Month Column (i)
* Projected

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Stranded Cost Reconciliation
May 2021 - April 2022

1	Rate G-1	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (7,585)	$ (20,196)	$ (23,869)	$ (3,673)	$ (11,258)	$ (9,421)	3.25%	$ (26)	$ (26)
4	Jun-21	$ (11,283)	$ (26,356)	$ (21,223)	$ 5,133	$ (6,150)	$ (8,717)	3.25%	$ (24)	$ (49)
5	Jul-21	$ (6,174)	$ (29,192)	$ (26,378)	$ 2,814	$ (3,360)	$ (4,767)	3.25%	$ (13)	$ (62)
6	Aug-21	$ (3,373)	$ (28,311)	$ (29,195)	$ (884)	$ (4,257)	$ (3,815)	3.25%	$ (10)	$ (72)
7	Sep-21	$ (4,267)	$ (28,628)	$ (28,313)	$ 315	$ (3,952)	$ (4,110)	3.25%	$ (11)	$ (84)
8	Oct-21	$ (3,963)	$ (22,875)	$ (28,628)	$ (5,753)	$ (9,716)	$ (6,840)	3.25%	$ (19)	$ (102)
9	Nov-21	$ (9,735)	$ (21,739)	$ (22,875)	$ (1,136)	$ (10,871)	$ (10,303)	3.25%	$ (28)	$ (130)
10	Dec-21	$ (10,899)	$ (25,079)	$ (21,739)	$ 3,340	$ (7,559)	$ (9,229)	3.25%	$ (25)	$ (155)
11	Jan-22	$ (7,584)	$ (26,544)	$ (25,079)	$ 1,465	$ (6,120)	$ (6,852)	3.25%	$ (19)	$ (173)
12	Feb-22	$ (6,138)	$ (26,189)	$ (25,066)	$ 1,124	$ (5,014)	$ (5,576)	3.25%	$ (15)	$ (189)
* 13	Mar-22	$ (5,029)	$ (25,606)	$ (25,606)	$ -	$ (5,029)	$ (5,029)	3.25%	$ (14)	$ (202)
* 14	Apr-22	$ (5,043)	$ (23,364)	$ (23,364)	$ -	$ (5,043)	$ (5,043)	3.25%	$ (14)	$ (216)
15		**Cumulative (Over)/Under Collection of Stranded Cost**				**$ (5,057)**				

1	Rate G-3	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (1,696)	$ (4,516)	$ (5,337)	$ (821)	$ (2,517)	$ (2,107)	3.25%	$ (6)	$ (6)
4	Jun-21	$ (2,523)	$ (5,894)	$ (4,746)	$ 1,148	$ (1,375)	$ (1,949)	3.25%	$ (5)	$ (11)
5	Jul-21	$ (1,381)	$ (6,528)	$ (5,899)	$ 629	$ (751)	$ (1,066)	3.25%	$ (3)	$ (14)
6	Aug-21	$ (754)	$ (6,331)	$ (6,529)	$ (198)	$ (952)	$ (853)	3.25%	$ (2)	$ (16)
7	Sep-21	$ (954)	$ (6,402)	$ (6,331)	$ 70	$ (884)	$ (919)	3.25%	$ (2)	$ (19)
8	Oct-21	$ (886)	$ (5,115)	$ (6,402)	$ (1,287)	$ (2,173)	$ (1,530)	3.25%	$ (4)	$ (23)
9	Nov-21	$ (2,177)	$ (4,861)	$ (5,115)	$ (254)	$ (2,431)	$ (2,304)	3.25%	$ (6)	$ (29)
10	Dec-21	$ (2,437)	$ (5,608)	$ (4,861)	$ 747	$ (1,690)	$ (2,064)	3.25%	$ (6)	$ (35)
11	Jan-22	$ (1,696)	$ (5,936)	$ (5,608)	$ 328	$ (1,368)	$ (1,532)	3.25%	$ (4)	$ (39)
12	Feb-22	$ (1,373)	$ (5,856)	$ (5,605)	$ 251	$ (1,121)	$ (1,247)	3.25%	$ (3)	$ (42)
* 13	Mar-22	$ (1,125)	$ (5,726)	$ (5,726)	$ -	$ (1,125)	$ (1,125)	3.25%	$ (3)	$ (45)
* 14	Apr-22	$ (1,128)	$ (5,225)	$ (5,225)	$ -	$ (1,128)	$ (1,128)	3.25%	$ (3)	$ (48)
15		**Cumulative (Over)/Under Collection of Stranded Cost**				**$ (1,131)**				

1	Rate G-2	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (2,826)	$ (7,525)	$ (8,893)	$ (1,368)	$ (4,195)	$ (3,510)	3.25%	$ (10)	$ (10)
4	Jun-21	$ (4,204)	$ (9,820)	$ (7,908)	$ 1,913	$ (2,292)	$ (3,248)	3.25%	$ (9)	$ (18)
5	Jul-21	$ (2,300)	$ (10,877)	$ (9,828)	$ 1,049	$ (1,252)	$ (1,776)	3.25%	$ (5)	$ (23)
6	Aug-21	$ (1,257)	$ (10,549)	$ (10,878)	$ (329)	$ (1,586)	$ (1,421)	3.25%	$ (4)	$ (27)
7	Sep-21	$ (1,590)	$ (10,667)	$ (10,549)	$ 117	$ (1,473)	$ (1,531)	3.25%	$ (4)	$ (31)
8	Oct-21	$ (1,477)	$ (8,523)	$ (10,667)	$ (2,144)	$ (3,620)	$ (2,549)	3.25%	$ (7)	$ (38)
9	Nov-21	$ (3,627)	$ (8,100)	$ (8,523)	$ (423)	$ (4,051)	$ (3,839)	3.25%	$ (10)	$ (48)
10	Dec-21	$ (4,061)	$ (9,344)	$ (8,100)	$ 1,245	$ (2,817)	$ (3,439)	3.25%	$ (9)	$ (58)
11	Jan-22	$ (2,826)	$ (9,890)	$ (9,345)	$ 546	$ (2,280)	$ (2,553)	3.25%	$ (7)	$ (65)
12	Feb-22	$ (2,287)	$ (9,758)	$ (9,339)	$ 419	$ (1,868)	$ (2,078)	3.25%	$ (6)	$ (70)
* 13	Mar-22	$ (1,874)	$ (9,541)	$ (9,541)	$ -	$ (1,874)	$ (1,874)	3.25%	$ (5)	$ (75)
* 14	Apr-22	$ (1,879)	$ (8,705)	$ (8,705)	$ -	$ (1,879)	$ (1,879)	3.25%	$ (5)	$ (80)
15		**Cumulative (Over)/Under Collection of Stranded Cost**				**$ (1,884)**				

1	Rate V	(Over)/ Under Beginning Balance	Stranded Cost Revenue (Refund)	CTC Expense (Credit)	Monthly (Over)/ Under	(Over)/ Under Ending Balance	Balance Subject to Interest	Interest Rate	Interest	Total Interest
2	Month	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
3	May-21	$ (6)	$ (16)	$ (19)	$ (3)	$ (9)	$ (8)	3.25%	$ (0)	$ (0)
4	Jun-21	$ (9)	$ (21)	$ (17)	$ 4	$ (5)	$ (7)	3.25%	$ (0)	$ (0)
5	Jul-21	$ (5)	$ (24)	$ (21)	$ 2	$ (3)	$ (4)	3.25%	$ (0)	$ (0)
6	Aug-21	$ (3)	$ (23)	$ (24)	$ (1)	$ (3)	$ (3)	3.25%	$ (0)	$ (0)
7	Sep-21	$ (3)	$ (23)	$ (23)	$ 0	$ (3)	$ (3)	3.25%	$ (0)	$ (0)
8	Oct-21	$ (3)	$ (19)	$ (23)	$ (5)	$ (8)	$ (6)	3.25%	$ (0)	$ (0)
9	Nov-21	$ (8)	$ (18)	$ (19)	$ (1)	$ (9)	$ (8)	3.25%	$ (0)	$ (0)
10	Dec-21	$ (9)	$ (20)	$ (18)	$ 3	$ (6)	$ (8)	3.25%	$ (0)	$ (0)
11	Jan-22	$ (6)	$ (22)	$ (20)	$ 1	$ (5)	$ (6)	3.25%	$ (0)	$ (0)
12	Feb-22	$ (5)	$ (21)	$ (20)	$ 1	$ (4)	$ (5)	3.25%	$ (0)	$ (0)
* 13	Mar-22	$ (4)	$ (21)	$ (21)	$ -	$ (4)	$ (4)	3.25%	$ (0)	$ (0)
* 14	Apr-22	$ (4)	$ (19)	$ (19)	$ -	$ (4)	$ (4)	3.25%	$ (0)	$ (0)
15		**Cumulative (Over)/Under Collection of Stranded Cost**				**$ (4)**				

(a) May-21 ties to the deferral account balance, all other months are Prior Month Column (e) + Prior Month Column (h)
(b) Company billing system report; Includes adjustment factor
(c) Per Dockets DE 19-025 (May 19 - Dec 19) and DE 20-016 (Jan 20 - April 20)
(d) Expense (Column c) - Revenue (Column b)
(e) Column (a) + Column (d)
(f) [Column (a) + Column (e)] ÷ 2
(g) Interest rate
(h) Column (f) x [Column (g) ÷ 12]
(i) Column (h) + Prior Month Column (i)
* Projected

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Transmission Charge Calculation
Rates by Class

		Total	D	D-10	G-1	G-2	G-3	Streetlights	T	V
1	**Estimate of Transmission Expense**	**$29,002,132**								
2	**Coincident Peak (KW)**	1,805,631	703,390	9,387	638,434	256,536	170,538	3,897	22,877	572
3	**Coincident Peak Allocator**	100.00%	38.96%	0.52%	35.36%	14.21%	9.44%	0.22%	1.27%	0.03%
4	**Allocated Transmission Expense**	$29,002,132	$11,297,882	$150,780	$10,254,551	$4,120,494	$2,739,196	$62,594	$367,444	$9,190
5	**Forecasted kWh Sales**	917,255,198	290,426,993	5,814,620	373,287,350	147,982,386	83,792,046	2,866,961	12,802,816	282,027
6	**Proposed Transmission Charge per kWh**	**$0.03161**	**$0.03890**	**$0.02593**	**$0.02747**	**$0.02784**	**$0.03269**	**$0.02183**	**$0.02870**	**$0.03258**
7	**Current Transmission Charge per kWh**	$0.03057	$0.03490	$0.02635	$0.02744	$0.03205	$0.02891	$0.01966	$0.02582	$0.02243
8	**Increase (Decrease) in Transmission Charge per kWh**	**$0.00104**	**$0.00400**	**($0.00042)**	**$0.00003**	**($0.00421)**	**$0.00378**	**$0.00217**	**$0.00288**	**$0.01015**

1 Schedule JDW-1, Line (10)
2 Schedule HMT/AMH-3, Page 2 of 7
3 Line (2) as a percent of total Line (2)
4 Line (1) x Line (3)
5 Per Company Forecast
6 Line (4) ÷ Line (5), truncated after 5 decimal places
7 Per Currently Effective Tariffs
8 Line (6) - Line (7)

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Transmission Charge Calculation
Coincident Peak Data for 2021

1		Total	D	D-10	G-1	G-2	G-3	Streetlights	T	V
2	January-21	141,208	54,972	1,096	46,122	21,127	14,274	602	2,946	69
3	February-21	139,707	53,489	925	46,301	21,173	14,654	612	2,482	71
4	March-21	135,275	60,006	1,054	41,218	17,827	11,710	606	2,775	79
5	April-21	117,338	30,425	615	51,273	18,983	14,365	0	1,645	32
6	May-21	163,328	57,788	716	66,146	23,467	13,557	5	1,616	33
7	June-21	196,228	87,840	779	61,347	26,365	18,218	4	1,626	49
8	July-21	178,476	69,805	645	62,926	25,738	17,952	4	1,356	50
9	August-21	190,756	86,018	794	60,750	25,144	16,320	5	1,678	47
10	September-21	153,779	53,335	617	61,627	22,737	14,097	5	1,323	38
11	October-21	124,294	38,880	520	54,985	17,740	10,254	651	1,235	29
12	November-21	129,339	50,605	779	44,139	18,598	12,428	723	2,030	37
13	December-21	135,903	60,227	847	41,600	17,637	12,709	680	2,165	38
14	Total	1,805,631	703,390	9,387	638,434	256,536	170,538	3,897	22,877	572

Source: Company Load Data

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Transmission Charge Reconciliation
May 2021 - April 2022

	1	**Month**	**(Over)/Under Beginning Balance**	**Transmission Revenue**	**Transmission Expense**	**Monthly (Over)/Under**	**(Over)/Under Ending Balance**	**Balance Subject to Interest**	**Interest Rate**	**Interest**	**Cumulative Interest**
	2		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	3	May-21	$3,466,842	$1,883,911	$2,339,860	$455,949	$3,922,792	$3,694,817	3.25%	$10,007	$10,007
	4	Jun-21	$3,932,798	$2,700,070	$2,881,277	$181,207	$4,114,005	$4,023,402	3.25%	$10,897	$20,904
	5	Jul-21	$4,124,902	$3,005,541	$3,020,519	$14,978	$4,139,880	$4,132,391	3.25%	$11,192	$32,095
	6	Aug-21	$4,151,072	$2,911,041	$2,221,544	($689,497)	$3,461,575	$3,806,323	3.25%	$10,309	$42,404
	7	Sep-21	$3,471,883	$2,941,018	$2,093,526	($847,492)	$2,624,391	$3,048,137	3.25%	$8,255	$50,660
	8	Oct-21	$2,632,647	$2,336,191	$1,651,655	($684,535)	$1,948,111	$2,290,379	3.25%	$6,203	$56,863
	9	Nov-21	$1,954,314	$2,234,256	$2,107,218	($127,038)	$1,827,276	$1,890,795	3.25%	$5,121	$61,984
	10	Dec-21	$1,832,397	$2,582,759	$2,535,042	($47,717)	$1,784,680	$1,808,539	3.25%	$4,898	$66,882
	11	Jan-22	$1,789,578	$2,747,629	$2,175,790	($571,840)	$1,217,739	$1,503,658	3.25%	$4,072	$70,954
	12	Feb-22	$1,221,811	$2,714,525	$2,400,109	($314,416)	$907,395	$1,064,603	3.25%	$2,883	$73,837
*	13	Mar-22	$910,278	$2,336,190	$2,336,190	($0)	$910,278	$910,278	3.25%	$2,465	$76,303
*	14	Apr-22	$912,744	$2,131,586	$2,131,586	$0	$912,744	$912,744	3.25%	$2,472	$78,775
	15			$30,524,717	$27,894,316						
	16		**Projected Cumulative (Over)/Under Collection of Transmission Charge:**					**$915,216**			

(a) May-21 ties to the deferral account balance, all other months are Prior Month Column (e) + Prior Month Column (h)
(b) Company financials
(c) Company financials
(d) Column (c) - Column (b)
(e) Column (a) + Column (d)
(f) [Column (a) + Column (e)] ÷ 2
(g) Interest rate on customer deposits
(h) Column (f) x [Column (g) ÷ 12]
(i) Column (h) + Prior Month Column (i)
* Projected

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Calculation of Transmission Service Cost Adjustment
Effective May 1, 2022 - April 30, 2023

1	Transmission Service (Over)/Under Collection	$915,216
2	Working Capital	($1,720)
3	Total	$913,496
4	Forecast kWh Deliveries	917,255,198
5	Transmission Service Cost Adjustment per kWh	$0.00100

1 Schedule HMT/AMH-3 Page 3
2 Schedule HMT/AMH-3 Page 5
3 Line (1) + Line (2)
4 Per Company forecast
5 Line (3) ÷ Line (4), truncated after 5 decimal places

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Transmission Service Cost Adjustment
Working Capital Calculation

		Days of Cost (a)	Invoice Payment Lag % (b)	Customer Payment Lag % (c)	CWC % (d)	Expense (e)	Working Capital Requirement (f)
1	2021 Transmission Costs	(60.68)	-16.62%	16.56%	-0.06%	$29,002,132	($18,388)
2	Working Capital Requirement						($18,388)
3	Capital Structure Post-tax						7.60%
4	Working Capital Impact						($1,397)
5	Capital Structure Pre-tax						9.36%
6	Working Capital Impact						($1,720)

Columns:
1(a) HMT/AMH-3 Page 6
(b) Column (a) ÷ 365
(c) HMT/AMH-3 Page 7
(d) Column (b) + Column (c)
1(e) HMT/AMH-3 Page 1
(f) Column (d) x Column (e)

Lines:
3 Per Settlement Agreement Docket No. DE 19-064
4 Line (2) x Line (3)
5 Per Settlement Agreement Docket No. DE 19-064
6 Line (2) x Line (5)

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Transmission Service Cost Adjustment
Working Capital Calculation
Expense Lead/Lag

	Bill Receipt Date	Expense Description	Invoice Amount	Service Period Mid-Point	Payment Date	Elapsed (Days)	% of Total	Weighted Days
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
1	Dec-20	NEP LNS Bill	$ 585,178.91	11/15/2020	1/14/2021	60	2.23%	1.34
2	Jan-21	ISO RNS-Bill	$ 1,522,858.42	11/15/2020	1/12/2021	58	5.80%	3.36
3	Jan-21	NEP LNS Bill	$ 280,535.09	12/16/2020	2/18/2021	64	1.07%	0.68
4	Feb-21	ISO RNS-Bill	$ 1,610,486.80	12/16/2020	2/17/2021	63	6.13%	3.86
5	Feb-21	NEP LNS Bill	$ 468,944.81	1/16/2021	3/19/2021	62	1.79%	1.11
6	Mar-21	ISO RNS-Bill	$ 1,610,317.55	1/16/2021	3/16/2021	59	6.13%	3.62
7	Mar-21	NEP LNS Bill	$ 478,712.00	2/14/2021	4/16/2021	61	1.82%	1.11
8	Apr-21	ISO RNS-Bill	$ 1,594,456.18	2/14/2021	4/13/2021	58	6.07%	3.52
9	Apr-21	NEP LNS Bill	$ 610,380.54	3/16/2021	5/20/2021	65	2.32%	1.51
10	May-21	ISO RNS-Bill	$ 1,544,698.85	3/16/2021	5/11/2021	56	5.88%	3.29
11	May-21	NEP LNS Bill	$ 479,584.14	4/15/2021	6/17/2021	63	1.83%	1.15
12	Jun-21	ISO RNS-Bill	$ 1,344,787.58	4/15/2021	6/16/2021	62	5.12%	3.18
13	Jun-21	NEP LNS Bill	$ 690,722.57	5/16/2021	7/22/2021	67	2.63%	1.76
14	Jul-21	ISO RNS-Bill	$ 1,785,156.23	5/16/2021	7/13/2021	58	6.80%	3.94
15	Jul-21	NEP LNS Bill	$ 461,605.36	6/15/2021	8/19/2021	65	1.76%	1.14
16	Aug-21	ISO RNS-Bill	$ 2,415,796.68	6/15/2021	8/18/2021	64	9.20%	5.89
17	Aug-21	NEP LNS Bill	$ 43,922.48	7/16/2021	9/20/2021	66	0.17%	0.11
18	Sep-21	ISO RNS-Bill	$ 2,189,125.13	7/16/2021	9/15/2021	61	8.34%	5.09
19	Sep-21	NEP LNS Bill	$ 161,248.16	8/16/2021	10/20/2021	65	0.61%	0.40
20	Oct-21	ISO RNS-Bill	$ 2,375,435.97	8/16/2021	10/13/2021	58	9.05%	5.25
21	Oct-21	NEP LNS Bill	$ 192,138.20	9/15/2021	11/19/2021	65	0.73%	0.48
22	Nov-21	ISO RNS-Bill	$ 1,889,457.17	9/15/2021	11/16/2021	62	7.20%	4.46
23	Nov-21	NEP LNS Bill	$ 362,227.40	10/16/2021	12/17/2021	62	1.38%	0.86
24	Dec-21	ISO RNS-Bill	$ 1,559,718.85	10/16/2021	12/15/2021	60	5.94%	3.56
25		Total	$26,257,495				Days	60.68

Columns:
(a) Month in which obligation for payment occurred
(b) Per invoices
(c) Per invoices
(d) Applicable service period
(e) Per invoices
(f) Column (e) - Column (d)
(g) Column (c) / Column (c) Line 25
(h) Column (f) x Column (g)

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Revenue Lead/Lag Applied to Transmission and Stranded Cost Mechanisms

Service Period		Monthly Customer Accts.Receivable	Monthly Sales	Days In Month	Average Daily Revenues
		(a)	(b)	(c)	(d)
1/1/2021	1/31/2021	$12,435,802	$9,042,451	31	$291,692
2/1/2021	2/28/2021	$12,995,651	$8,684,703	28	$310,168
3/1/2021	3/31/2021	$11,960,601	$8,424,569	31	$271,760
4/1/2021	4/30/2021	$11,003,450	$7,505,619	30	$250,187
5/1/2021	5/31/2021	$10,860,373	$6,979,864	31	$225,157
6/1/2021	6/30/2021	$12,023,704	$8,806,485	30	$293,549
7/1/2021	7/31/2021	$12,741,650	$9,838,104	31	$317,358
8/1/2021	8/31/2021	$13,387,406	$9,932,489	31	$320,403
9/1/2021	9/30/2021	$13,659,859	$10,320,288	30	$344,010
10/1/2021	10/31/2021	$12,404,962	$8,242,529	31	$265,888
11/1/2021	11/30/2021	$12,143,473	$8,248,924	30	$274,964
12/1/2021	12/31/2021	$13,306,088	$9,689,430	31	$312,562
	Average	$12,410,252			$289,808
1 Service Lag					15.21
2 Collection Lag					42.82
3 Billing Lag					2.59
4 Total Average Days Lag					60.62
5 Customer Payment Lag-annual percent					16.56%

Columns:

(a) Accounts Receivable per general ledger at end of applicable month
(b) Per Company billing data
(c) Number of days in applicable service period
(d) Column (b) ÷ Column (c)

Lines:

1 Per Settlement Agreement Docket No. DE 19-064
2 (a) / (d)
3 Per Settlement Agreement Docket No. DE 19-064
4 Line (1) + Line (2) + Line (3)
5 Line (5) ÷ 365

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Calculation of RGGI Auction Proceeds Refund

		Month	Beginning Balance With Interest	RGGI Rebate	Actual Refund	(Over)/Under Balance	Balance Subject to Interest	Effective Interest Rate	Interest	Cumulative Interest
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	1	May-21	($510,942)		($114,242)	($396,700)	($453,821)	3.25%	($1,229)	($1,229)
	2	Jun-21	($397,929)	($491,892)	($163,784)	($726,037)	($561,983)	3.25%	($1,522)	($2,751)
	3	Jul-21	($727,559)	($469,282)	($181,627)	($1,015,214)	($871,386)	3.25%	($2,360)	($5,111)
	4	Aug-21	($1,017,574)		($176,194)	($841,380)	($929,477)	3.25%	($2,517)	($7,628)
	5	Sep-21	($843,897)		($178,166)	($665,731)	($754,814)	3.25%	($2,044)	($9,673)
	6	Oct-21	($667,775)		($142,376)	($525,399)	($596,587)	3.25%	($1,616)	($11,289)
	7	Nov-21	($527,015)	($558,829)	($135,313)	($950,531)	($738,773)	3.25%	($2,001)	($13,289)
	8	Dec-21	($952,532)		($156,090)	($796,442)	($874,487)	3.25%	($2,368)	($15,658)
	9	Jan-22	($798,811)	($937,043)	($165,198)	($1,570,656)	($1,184,733)	3.25%	($3,209)	($18,866)
	10	Feb-22	($1,573,864)		($149,972)	($1,423,892)	($1,498,878)	3.25%	($4,059)	($22,926)
*	11	Mar-22	($1,427,952)		($159,372)	($1,268,580)	($1,348,266)	3.25%	($3,652)	($26,577)
*	12	Apr-22	($1,272,232)		($145,414)	($1,126,818)	($1,199,525)	3.25%	($3,249)	($29,826)
	13		Total	($2,457,046)	($1,867,747)	($1,130,067)				

14	2021 (Over)/Under Refund	($1,130,067)
15	Forecasted 2022 RGGI Refund	($2,457,046)
16	Total Refund Due	($3,587,112)
17	Forecast kWh Deliveries	917,255,198
18	RGGI Refund Rate Effective 5/1/2022	($0.00391)

(a) May-21 ties to the deferral account balance, all other months are Prior Month Column (e) + Prior Month Column (h)
(b) Company financials
(c) Company financials
(d) Column (a) - [(Column (c) - Column (b)]
(e) Average of Column (a) and Column (c)
(f) Interest rate on customer deposits
(g) Column (e) x [Column (f) ÷ 12]
(h) Prior month Column (h) + Current month Column (g)
14 Sum of column (d)
15 Forecast based on 2021 auction proceeds
16 Sum of lines 14 + 15
17 Company forecast
18 Line 16 / Line 17
* Estimate

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Docket No. DE 22-___
Schedule HMT/AMH-5
Page 1 of 4

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Property Tax Adjustment Mechanism
Rate Calculation

	Rate	PTAM	Forecasted	Transmission Rate
			Distribution	PTAM Portion
1	Year	2020 & 2021	(kWh)	($/kWh)
2	Col. A	Col. B	Col. C	Col. D
3	2022	$330,873	917,255,198	$ 0.00036

Col. A: Effective year (May 1, 2022 - April 30, 2023)
Col. B: Schedule HMT/AMH-5 page 2 line 23
Col. C: Company Forecast
Col. D: Column B / Column C

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Property Tax Adjustment Mechanism
Property Tax Summary

Line	Amount	Reference
1	Tax Year 2020	
2	$4,798,551	DE 19-064 Corrections & Updates Filing Bates 16 Line 107
3	($962,839)	State Property Taxes in DE 19-064
4	$3,835,712	Sum of lines 1 + 2
5	($19,378)	CY2019 REP
6	$26,743	CY2020 REP
7	$198,142	2019 Step Increase Effective July 1, 2020 (9 months included)
8	$4,041,219	Total 2020 Property Taxes in Rates
9	Tax Year 2021	
	$4,041,219	Total 2020 property taxes to be collected in rates in 2021
10	$66,047	2019 Step Increase Effective July 1, 2020 (3 months included)
8	$220,911	2020 Step Increase Eff. July 1, 2021 (9 months of $294,548 - Order No. 26,494)
9	$7,170	2020 Step Increase (5 months of $17,208 - Order No. 26,537)
10	$4,335,347	Total
11	$8,376,566	Total Property Taxes Collected in Rates 2020 + 2021
12	Property Tax Billed	
13	$4,514,178	2020 Municipal Property Taxes Billed
14	$4,193,261	2021 Municipal Property Taxes Billed
15	$8,707,439	Total
16	Property Taxes Collected in Rates	
17	$4,041,219	2020
18	$4,335,347	2021
19	$8,376,566	Total
20	Difference	
21	$472,959	2020
22	($142,086)	2021
23	$330,873	Increase To Base Rates Due To Municipal Property Tax Reconciliation

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Property Tax Adjustment Mechanism
Municipal Property 2020 Tax Invoices

			Tax Year 2020		
Line	Municipality	Parcel	Installment #1	Installment #2	Total Due
1	Acworth	999-00000-00999-00D	$ 12,073.00	$ 14,842.00	$ 26,915.00
2	Alstead	999-UTIL-001	$ 39,127.00	$ 53,231.00	$ 92,358.00
3	Atkinson	00UTIL-000001-000000	$ 3.00	$ 142.00	$ 145.00
4	Bath	00-GSE	$ 603.54	$ 1,183.03	$ 1,786.57
5	Canaan	00UTIL-00ELEC-000001	$ 66,367.00	$ 72,550.00	$ 138,917.00
6	Charlestown	119-033	$ 2,023.47	$ 1,973.42	$ 3,996.89
7	Charlestown	000-003	$ 170,476.00	$ 94,288.04	$ 264,764.04
8	Charlestown	103-050	$ 1,019.41	$ 988.39	$ 2,007.80
9	Charlestown	103-051	$ 6.93	$ 6.33	$ 13.26
10	Charlestown	107-001	$ 25.01	$ 22.92	$ 47.93
11	Cornish	000UTL - 000UTL - 00ELEC	$ 2,030.00	$ 3,286.00	$ 5,316.00
12	Derry	11-100	$ 2,211.27	$ 2,678.72	$ 4,889.99
13	Enfield		$ 988.14	$ 1,035.60	$ 2,023.74
14	Enfield		$ 84,798.54	$ 116,167.58	$ 200,966.12
15	Franconia	00UTIL-0ELECT-000004	$ 132.32	$ -	$ 132.32
16	Grafton	000UTL-00001-00000	$ 976.00	$ 398.00	$ 1,374.00
17	Goffstown	99-4-3	$ 135.12	$ 109.16	$ 244.28
18	Hanover	0-0-11	$ 101,528.00	$ 137,081.00	$ 238,609.00
19	Hanover	23-1-1	$ 2,663.00	$ 2,812.00	$ 5,475.00
20	Langdon	1-00000.-0	$ 15,454.00	$ 14,973.72	$ 30,427.72
21	Lebanon	103-14	$ 50,573.00	$ 811,955.00	$ 862,528.00
22	Lebanon	105-105	$ 2,013.00	$ 2,086.00	$ 4,099.00
23	Lebanon	116-4	$ 50.00	$ 31.00	$ 81.00
24	Lebanon	117-17	$ 793.00	$ 689.00	$ 1,482.00
25	Lebanon	6-1	$ 3,169.00	$ 2,662.00	$ 5,831.00
26	Lebanon	999-2	$ 375,746.00	$ -	$ 375,746.00
27	Londonderry	81-14-1	$ -	$ 5,187.00	$ 5,187.00
28	Londonderry	81-14-0	$ 8,433.00	$ 7,982.40	$ 16,415.40
29	Marlow	U7C	$ 477.49	$ 526.64	$ 1,004.13
30	Monroe	000000-000002-000000	$ 4,848.86	$ 3,711.08	$ 8,559.94
32	Orange	00UTLS-000GSE-000000	$ -	$ 1,914.86	$ 1,914.86
33	Pelham	0-14-3	$ 121,695.00	$ 148,177.00	$ 269,872.00
34	Pelham	29-7-114-1-UBO	$ 26,406.00	$ 28,668.00	$ 55,074.00
35	Plainfield	000233-000020-000000	$ 25,859.00	$ 31,821.00	$ 57,680.00
36	Salem	67-9809	$ 1,603.00	$ 1,610.00	$ 3,213.00
37	Salem	68-10101	$ 257.00	$ 258.00	$ 515.00
38	Salem	68-10102	$ 301.00	$ 303.00	$ 604.00
39	Salem	68-10103	$ 162.00	$ 165.00	$ 327.00
40	Salem	89-1099	$ 818.03	$ 730.00	$ 1,548.03
41	Salem	89-10115	$ 1,061.00	$ 1,066.00	$ 2,127.00
42	Salem	99-12572	$ 10,869.99	$ 10,914.99	$ 21,784.98
43	Salem	114-10116	$ 772.09	$ 689.00	$ 1,461.09
44	Salem	116-9915	$ 12,418.62	$ 11,090.00	$ 23,508.62
45	Salem	116-9915-2	$ 925.04	$ 827.00	$ 1,752.04
46	Salem	136-9903	$ 1,562.00	$ 1,568.00	$ 3,130.00
47	Salem	157-9715 & 157-9715-1 & 157-9715-2	$ 683,931.00	$ 753,815.19	$ 1,437,746.19
48	Springfield	000000-000000-000003-0091-07	$ 130.00	$ 117.00	$ 247.00
49	Surry	000UTL-000003-000GSE	$ 2,012.00	$ 3,102.00	$ 5,114.00
50	Tilton	00UTL-000LIB-000GSE	$ 174.00	$ 100.00	$ 274.00
51	Walpole	00UTIL-00UTIL-00001B	$ 58,372.00	$ 129,643.00	$ 188,015.00
52	Walpole	00UTIL-00UTIL-00001A	$ 18,647.00	$ 39,190.00	$ 57,837.00
53	Windham	00B-00000-02795	$ 25,811.00	$ 51,638.00	$ 77,449.00
54	Windham	00A-00000-23658	$ 797.00	$ 844.00	$ 1,641.00
55					
56	TOTAL		$ 1,943,327.87	$ 2,570,850.07	$ 4,514,177.94

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Property Tax Adjustment Mechanism
Municipal Property 2021 Tax Invoices

			Tax Year 2021		
Line	Municipality	Parcel	Installment #1	Installment #2	Total Due
1	Acworth	999-00000-00999-00D	$ 13,458.00	$ 8,493.00	$ 21,951.00
2	Alstead	999-UTIL-001	$ 46,179.00	$ 56,519.00	$ 102,698.00
3	Atkinson	00UTIL-000001-000000	$ 72.00	$ 1,998.00	$ 2,070.00
4	Bath	00-GSE	$ 893.29	$ 760.98	$ 1,654.27
5	Canaan	00UTIL-00ELEC-000001	$ 69,458.00	$ 33,980.00	$ 103,438.00
6	Charlestown	119-033	$ 2,111.93	$ 1,222.93	$ 3,334.86
7	Charlestown	000-003	$ 155,373.69	$ 147,084.22	$ 302,457.91
8	Charlestown	103-050	$ 1,063.56	$ 1,408.28	$ 2,471.84
9	Charlestown	103-051	$ 7.03	$ 6.18	$ 13.21
10	Charlestown	107-001	$ 25.39	$ 23.22	$ 48.61
11	Cornish	000UTL - 000UTL - 00ELEC	$ 2,660.00	$ 3,528.00	$ 6,188.00
12	Derry	11-100	$ 2,445.00	$ 3,011.34	$ 5,456.34
13	Enfield	0033-0034-00000-00000	$ 1,012.30	$ 986.41	$ 1,998.71
14	Enfield	0UTL-0001-00000-00000	$ 100,521.41	$ 115,068.08	$ 215,589.49
15	Franconia	00UTIL-0ELECT-000004	$ -	$ -	$ -
16	Grafton	000UTL-00001-00000	$ 687.00	$ 730.00	$ 1,417.00
17	Goffstown	99-4-3	$ 116.43	$ 116.03	$ 232.46
18	Hanover	0-0-11	$ 119,304.00	$ 99,046.00	$ 218,350.00
19	Hanover	23-1-1	$ 2,738.00	$ -	$ 2,738.00
20	Langdon	1-00000.-0	$ 15,887.75	$ 14,012.13	$ 29,899.88
21	Lebanon	103-14	$ 433,353.00	$ 491,120.00	$ 924,473.00
22	Lebanon	105-105	$ 2,049.00	$ 1,970.00	$ 4,019.00
23	Lebanon	116-4	$ 43.00	$ 42.00	$ 85.00
24	Lebanon	117-17	$ 741.00	$ 732.00	$ 1,473.00
25	Lebanon	157/1	$ 14,250.00	$ 14,124.00	$ 28,374.00
26	Lebanon	157/2	$ 4,191.00	$ 4,155.00	$ 8,346.00
27	Lebanon	6-1	$ 2,915.00	$ 2,419.00	$ 5,334.00
28	Lebanon	999-2	$ 67,879.00	$ 42,024.00	$ 109,903.00
29	Londonderry	81-14-1	$ 777.90	$ 9,115.20	$ 9,893.10
30	Londonderry	81-14-0	$ 8,207.70	$ 6,044.70	$ 14,252.40
31	Marlow	U7C	$ 502.60	$ 489.96	$ 992.56
32	Monroe	000000-000002-000000	$ 4,279.97	$ 4,588.26	$ 8,868.23
33	Nashua	0041-00011	$ 8.21	$ 8.67	$ 16.88
34	Orange	00UTLS-000GSE-000000	$ -	$ 1,892.21	$ 1,892.21
35	Pelham	0-14-3	$ 134,936.00	$ 44,505.00	$ 179,441.00
36	Pelham	29-7-114-1-UBO	$ 27,537.00	$ 34,760.00	$ 62,297.00
37	Plainfield	000233-000020-000000	$ 28,840.00	$ 27,050.00	$ 55,890.00
38	Salem	67-9809	$ 1,606.00	$ 1,226.00	$ 2,832.00
39	Salem	68-10101	$ 257.00	$ 217.00	$ 474.00
40	Salem	68-10102	$ 302.00	$ 252.00	$ 554.00
41	Salem	68-10103	$ 163.00	$ 136.00	$ 299.00
42	Salem	89-1099	$ 820.00	$ 367.00	$ 1,187.00
43	Salem	89-10115	$ 1,063.00	$ 785.00	$ 1,848.00
44	Salem	99-12572	$ 12,101.00	$ 6,714.00	$ 18,815.00
45	Salem	114-10116	$ 774.00	$ -	$ 774.00
46	Salem	116-9915	$ 12,445.00	$ 5,576.00	$ 18,021.00
47	Salem	116-9915-2	$ 927.00	$ 416.00	$ 1,343.00
48	Salem	136-9903	$ 1,564.00	$ 1,155.00	$ 2,719.00
49	Salem	157-9715	$ 74,095.00	$ 27,530.00	$ 101,625.00
50	Salem	157/9715/1	$ 644,073.00	$ 664,227.00	$ 1,308,300.00
51	Salem	157/9715/2	$ 706.00	$ -	$ 706.00
52	Springfield	000000-000000-000003-0091-07	$ 124.00	$ 86.00	$ 210.00
53	Surry	000UTL-000003-000GSE	$ 2,556.00	$ 154.00	$ 2,710.00
54	Tilton	00UTL-000LIB-000GSE	$ 136.00	$ 100.00	$ 236.00
55	Walpole	00UTIL-00UTIL-00001B	$ 94,046.00	$ 77,092.00	$ 171,138.00
56	Walpole	00UTIL-00UTIL-00001A	$ 28,939.00	$ 23,737.00	$ 52,676.00
57	Windham	00B-00000-02795	$ 38,724.00	$ 29,345.00	$ 68,069.00
58	Windham	00A-00000-23658	$ 820.00	$ 347.00	$ 1,167.00
59					
60	TOTAL		$ 2,180,765.16	$ 2,012,495.80	$ 4,193,260.96

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Docket No. DE 22-___
Schedule HMT/AMH-6
Page 1 of 1

Liberty Utilities (Granite State Electric) Corp. d/b/a Liberty
Typical Residential Customer
Retail Rate Filing Bill Comparison

1	Usage 650 kWh				
2		Current Rates	May 1, 2022 Proposed Rates	Current Bill	May 1, 2022 Proposed Bill
3	Customer Charge	$14.74	$14.74	$14.74	$14.74
4	Distribution Charge				
5	Base	$0.06038	$0.06038	$39.25	$39.25
6	VMP	$0.00064	$0.00064	$0.42	$0.42
7	Storm Recovery Adjustment	$0.00000	$0.00000	$0.00	$0.00
8	Transmission Charge	$0.03703	$0.03635	$24.07	$23.62
9	Stranded Cost Charge	($0.00080)	($0.00051)	-$0.52	-$0.33
10	System Benefits Charge	$0.00678	$0.00678	$4.41	$4.41
11	Electricity Consumption Tax	$0.00000	$0.00000	$0.00	$0.00
12	Subtotal Retail Delivery Services	$0.10403	$0.10363	$82.36	$82.10
13	Default Service Charge	$0.11119	$0.11119	$72.27	$72.27
14	Total Bill			$154.63	$154.38
15	**Monthly $ decrease in 650 kWh Total Residential Bill**			**($0.26)**	
16	**Monthly % decrease in 650 kWh Total Residential Bill**			**-0.17%**	

38. Reliability Enhancement Program Capital Investment Allowance

Distribution base rates are subject to adjustment on an annual basis for a Reliability Enhancement Program Capital Investment Allowance pursuant to the Settlement Agreement in Docket DE 19-064.

39. Transmission Charge

The Transmission Charge will recover, on a fully reconciling basis, the costs incurred by the Company for transmission related services, and other reconciling charges as noted below. These costs include charges billed to the Company by Other Transmission Providers; third party charges billed to the Company for transmission related services such as charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges; and transmission-based assessments or fees billed by or through regulatory agencies, including those associated with the ISO-NE, regional transmission group, an independent system operator, an RTO and their successors, or other such body with the oversight of regional transmission, in the event that any of these entities are authorized to bill the Company directly for their services.

The Transmission Charge shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any over recovery or under recovery occurring in the prior year. The Company may file to change the rates at any time if a significant over recovery or under recovery occurs. Interest on over recoveries or under recoveries shall be calculated at the prime rate.

Any changes to rates determined under the charge shall only be made following a notice filed with the Commission setting forth the amount of the increase or decrease, the new rates for each rate class, and the effective date of such new rates.

The Transmission Charge includes the Regional Greenhouse Gas Initiative (“RGGI”) refund as required by RSA 125-O:23,II and Order No. 25,664 dated May 9, 2014, which directs the Company to refund RGGI auction revenue it receives to its customers.

The Revenue Decoupling Adjustment Clause (RDAC) will be included in the transmission charge annual rate filing for reconciliation. The RDAC is further described in Section 39A of the Tariff.

The Property Tax Adjustment Mechanism (PTAM) will be included in the transmission charge annual rate filing for reconciliation. The PTAM is further described in Section 39B of the Tariff.

39A. Revenue Decoupling Adjustment Clause

Purpose

The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company subject to the jurisdiction of the NHPUC to adjust, on an annual basis, its rates for firm sales in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's Revenue Decoupling Adjustment eliminates the link between customer sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

Effective Date

The Revenue Decoupling Adjustment Factor ("RDAF") shall be effective on the first day of the Decoupling Year.

Applicability

The Revenue Decoupling Adjustment Factor shall apply to all of the Company's tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this Tariff.

Definitions

i. The following definitions shall apply throughout the Tariff:

1. Actual Base Revenue per Customer is the actual revenue derived from the Company's base rates divided by the number of customers for a given year for a Customer Class.
2. Actual Number of Customers is the actual number of customers for the applicable Customer Class for the most recently completed year. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for a given year for a Customer Class and dividing by the number of months in that year.
3. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.
4. Decoupling Year. The first Decoupling Year shall be the 12-month period from July 1, 2021 to June 30, 2022. Each subsequent Decoupling Year shall be the twelve months commencing July 1 through June 30.
5. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

Calculation of Revenue Decoupling Adjustment

i. Description of Revenue Decoupling Adjustment

At the Decoupling Year, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next corresponding season.

The Revenue Decoupling Adjustment shall be determined by calculating the difference between the actual Revenue per Customer and the Benchmark Base Revenue per Customer and multiplying that difference by the Actual Number of Customers for the applicable Customer Class. The Revenue Decoupling Adjustment shall equal the sum of the adjustments calculated for all Customer Classes and shall include a reconciliation component. There shall be a 3% cap on the amount refunded or charged to customers. The 3% cap shall be equal to 0.03 times the allowed revenue requirement subject to annual adjustments. The decoupling amount will be recovered or refunded during the following year up to the 3% cap. Any amounts in excess of the 3% cap will be deferred and recovered or refunded in future periods, as determined by the Commission. Any amounts deferred will be added to the aggregate decoupling adjustment amount of the following periods until recovered or refunded such that there is a maximum adjustment of 3% refunded or charged each year. Any over- or under-collection shall carry interest at the prime rate.

The amounts to be refunded or collected under this decoupling mechanism shall be calculated annually using monthly accruals. These monthly accruals will be summed for each decoupling year and presented in the annual reconciliation filing. Monthly decoupling accruals are calculated as follows:

a) The monthly target revenues per customer (“Monthly Target RPC”) amounts will be determined for each of the Company’s rate classes by:

i) allocating each years’ allowed revenue requirement to each rate class, by month, in proportion to the test year with the following exceptions:

(1) Rate classes M, LED-1, and LED-2 will not be included in the decoupling calculations;
(2) Rate classes D-11 and EV, will not be included in the decoupling calculations as they are new rate classes. The inclusion of those rate classes will be reevaluated in the next rate case; and

ii) dividing each class monthly target revenue number by the number of monthly customer bills from the test year.

b) The Monthly Actual RPC will be calculated as the actual monthly revenues by rate class divided by the actual number of bills for each rate class rendered during that month.

c) The Monthly Actual RPC will be compared to the Monthly Target RPC for each rate class. The difference between the Monthly Actual RPC and the Monthly Target RPC for each rate class will then be multiplied times the actual number of bills rendered for each rate class to determine the monthly revenue shortfall/surplus for each class, the sum of which will constitute the total monthly revenue shortfall/surplus.

d) At the end of the reconciliation period, the monthly amounts will be summed to determine the cumulative annual revenue shortfall/surplus.

e) Subject to the cap described above, the Annual Allowed Adjustment revenue shortfall/surplus, will be allocated to the classes using the Rate Class Allocation as detailed on Line 115 of Attachment 5, page 4 of the Settlement Agreement in Docket No. DE 19-064.

f) The amount allocated to each rate class will be allocated to the kWh and kW rate adjustments for each class on the basis of the actual kWh and kW's of the decoupling year.

ii. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CC=1}^{CC=3} \left[\left(BRPC_{T-1}^{CG} - ARPC_{T-1}^{CC} \right) x \; ACUSTS_{T-1}^{CC} \right]$$

And

$$RDAF = \frac{RD}{FV}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CC}$: The actual number of customers for the applicable Customer Class for the most recently completed Decoupling Year. Actual number of customers for each Decoupling Year shall be the average number monthly customers in that season, calculated by summing the number of billed customers in each month of the most recently completed Decoupling Year, and dividing by the number of months in that year.

$ARPC_{T-1}^{CC}$: The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Decoupling Year (T-1), as defined in Section i.

$BRPC_{T-1}^{CC}$: The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section i.2. for the most recently completed Decoupling Year (T-1).

cc	Customer Classes as defined in Section i.3.
RD	The Revenue Decoupling adjustment to revenues.
$RDAF_T$:	The Revenue Decoupling Adjustment Factor.
FV	Forecast sales volumes for the Billing Year.

1.0 Application of the RDAF to Customer Bills

The RDAF ($ per kWh) shall be truncated at the nearest one one-hundredth of a cent per kWh. The RDAF will be applied to the monthly tariff sales for each customer.

2.0 Information to be Filed with the Commission

Information pertaining to the RDAF will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the Tariff. Such information shall include:

1. The calculation of the applicable revenue decoupling revenue dollar adjustment for the Decoupling Year by Customer Class Group.
2. The calculation of the proposed decoupling rate per kWh for all firm rates to be applied in the Billing Year.
3. The calculation of the monthly Benchmark Base Revenue per Customer, to be utilized in the upcoming Decoupling Year. If distribution rates change during the Decoupling Year, the monthly Benchmark Base Revenue per Customer for the remaining months of the Decoupling Year will be revised and filed with the Commission.

39B. Property Tax Adjustment Mechanism (PTAM)

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with Actual municipal property taxes from the property tax bills received in the prior calendar year are compared to the amount of municipal property taxes. At the end of the corresponding April 1 through March 31 property tax year and any over- or under-recoveries are adjusted annually through the PTAM. The PTAM is based on a full reconciliation with monthly compounded interest for any over- or under-recoveries occurring in prior year(s). Interest is calculated at the prime rate, fixed on a quarterly basis and established as reported in the Wall Street Journal on the first business day of the month preceding the calendar quarter ("Prime Rate").

2. The PTAM Rate shall be applied to all rate classes. The PTAM Rate shall be filed with the Company's transmission charge filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the PTAM Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. Reconciliation Adjustment: At the end of the corresponding April 1 through March 31 property tax year and any over- or under-recoveries are adjusted annually through the PTAM. The PTAM is based on a full reconciliation with monthly compounded interest for any over- or under-recoveries occurring in prior year(s). Interest is calculated at the prime rate, fixed on a quarterly basis and established as reported in the Wall Street Journal on the first business day of the month preceding the calendar quarter ("Prime Rate").

40. Electricity Consumption Tax Charge

All Customers shall be obligated to pay the Electricity Consumption Tax Charge in accordance with New Hampshire Statute RSA Chapter 83-E, which may be revised from time to time, in addition to all other applicable rates and charges under this Tariff. The Electricity Consumption Tax Charge shall appear separately on all Customer bills. Any discounts provided for under a Special Contract shall not apply to the Electricity Consumption Tax Charge.

41. System Benefits Charge

All customers taking delivery service shall pay the System Benefits Charge as required by New Hampshire law and approved by the Commission. The System Benefits Charge shall recover the

38. Reliability Enhancement Program Capital Investment Allowance

Distribution base rates are subject to adjustment on an annual basis for a Reliability Enhancement Program Capital Investment Allowance pursuant to the Settlement Agreement in Docket DE 19-064.

39. Transmission Charge

The Transmission Charge will recover, on a fully reconciling basis, the costs incurred by the Company for transmission related services, and other reconciling charges as noted below. These costs include charges billed to the Company by Other Transmission Providers; third party charges billed to the Company for transmission related services such as charges relating to the stability of the transmission system which the Company is authorized to recover by order of the regulatory agency having jurisdiction over such charges; and transmission-based assessments or fees billed by or through regulatory agencies, including those associated with the ISO-NE, regional transmission group, an independent system operator, an RTO and their successors, or other such body with the oversight of regional transmission, in the event that any of these entities are authorized to bill the Company directly for their services.

The Transmission Charge shall be established annually based on a forecast of includable costs, and shall also include a full reconciliation with interest for any over recovery or under recovery occurring in the prior year. The Company may file to change the rates at any time if a significant over recovery or under recovery occurs. Interest on over recoveries or under recoveries shall be calculated at the prime rate.

Any changes to rates determined under the charge shall only be made following a notice filed with the Commission setting forth the amount of the increase or decrease, the new rates for each rate class, and the effective date of such new rates.

The Transmission Charge includes the Regional Greenhouse Gas Initiative (“RGGI”) refund as required by RSA 125-O:23,II and Order No. 25,664 dated May 9, 2014, which directs the Company to refund RGGI auction revenue it receives to its customers.

The Revenue Decoupling Adjustment Clause (RDAC) will be included in the transmission charge annual rate filing for reconciliation. The RDAC is further described in Section 39A of the Tariff.

The Property Tax Adjustment Mechanism (PTAM) will be included in the transmission charge annual rate filing for reconciliation. The PTAM is further described in Section 39B of the Tariff.

39A. Revenue Decoupling Adjustment Clause

Purpose

The purpose of the Revenue Decoupling Adjustment Clause ("RDAC") is to establish procedures that allow the Company subject to the jurisdiction of the NHPUC to adjust, on an annual basis, its rates for firm sales in order to reconcile Actual Base Revenue per Customer with Benchmark Base Revenue per Customer. The Company's Revenue Decoupling Adjustment eliminates the link between customer sales and Company revenue in order to align the interests of the Company and customers with respect to changing customer usage.

Effective Date

The Revenue Decoupling Adjustment Factor ("RDAF") shall be effective on the first day of the Decoupling Year.

Applicability

The Revenue Decoupling Adjustment Factor shall apply to all of the Company's tariff Rate Schedules, subject to the jurisdiction of the Commission, as determined in accordance with the provisions of this Tariff.

Definitions

i. The following definitions shall apply throughout the Tariff:

1. Actual Base Revenue per Customer is the actual revenue derived from the Company's base rates divided by the number of customers for a given year for a Customer Class.
2. Actual Number of Customers is the actual number of customers for the applicable Customer Class for the most recently completed year. Actual Number of Customers shall be calculated by summing the monthly equivalent bills for a given year for a Customer Class and dividing by the number of months in that year.
3. Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.
4. Decoupling Year. The first Decoupling Year shall be the 12-month period from July 1, 2021 to June 30, 2022. Each subsequent Decoupling Year shall be the twelve months commencing July 1 through June 30.
5. Benchmark Base Revenue per Customer is the monthly allowed distribution revenue per Equivalent Bill for a given Decoupling Year for a given Customer Class, reflecting the distribution revenue level and approved equivalent bills from the Company's most recent rate case or other proceeding that results in an adjustment to base rates. Benchmark Base Revenue per Customer will be calculated for each month based on the distribution rates in effect at the start of the Decoupling Year and the calculation will be revised for the remaining months of each Decoupling Year if there is a distribution rate change that occurs following the beginning month of each Decoupling Year.

Calculation of Revenue Decoupling Adjustment

i. Description of Revenue Decoupling Adjustment

At the Decoupling Year, the Company shall calculate a Decoupling Revenue Adjustment to be used to determine the RDAF for the next corresponding season.

The Revenue Decoupling Adjustment shall be determined by calculating the difference between the actual Revenue per Customer and the Benchmark Base Revenue per Customer and multiplying that difference by the Actual Number of Customers for the applicable Customer Class. The Revenue Decoupling Adjustment shall equal the sum of the adjustments calculated for all Customer Classes and shall include a reconciliation component. There shall be a 3% cap on the amount refunded or charged to customers. The 3% cap shall be equal to 0.03 times the allowed revenue requirement subject to annual adjustments. The decoupling amount will be recovered or refunded during the following year up to the 3% cap. Any amounts in excess of the 3% cap will be deferred and recovered or refunded in future periods, as determined by the Commission. Any amounts deferred will be added to the aggregate decoupling adjustment amount of the following periods until recovered or refunded such that there is a maximum adjustment of 3% refunded or charged each year. Any over- or under-collection shall carry interest at the prime rate.

The amounts to be refunded or collected under this decoupling mechanism shall be calculated annually using monthly accruals. These monthly accruals will be summed for each decoupling year and presented in the annual reconciliation filing. Monthly decoupling accruals are calculated as follows:

a) The monthly target revenues per customer ("Monthly Target RPC") amounts will be determined for each of the Company's rate classes by:

i) allocating each years' allowed revenue requirement to each rate class, by month, in proportion to the test year with the following exceptions:

(1) Rate classes M, LED-1, and LED-2 will not be included in the decoupling calculations;
(2) Rate classes D-11 and EV, will not be included in the decoupling calculations as they are new rate classes. The inclusion of those rate classes will be reevaluated in the next rate case; and

ii) dividing each class monthly target revenue number by the number of monthly customer bills from the test year.

b) The Monthly Actual RPC will be calculated as the actual monthly revenues by rate class divided by the actual number of bills for each rate class rendered during that month.

c) The Monthly Actual RPC will be compared to the Monthly Target RPC for each rate class. The difference between the Monthly Actual RPC and the Monthly Target RPC for each rate class will then be multiplied times the actual number of bills rendered for each rate class to determine the monthly revenue shortfall/surplus for each class, the sum of which will constitute the total monthly revenue shortfall/surplus.

d) At the end of the reconciliation period, the monthly amounts will be summed to determine the cumulative annual revenue shortfall/surplus.

e) Subject to the cap described above, the Annual Allowed Adjustment revenue shortfall/surplus, will be allocated to the classes using the Rate Class Allocation as detailed on Line 115 of Attachment 5, page 4 of the Settlement Agreement in Docket No. DE 19-064.

f) The amount allocated to each rate class will be allocated to the kWh and kW rate adjustments for each class on the basis of the actual kWh and kW's of the decoupling year.

ii. Revenue Decoupling Adjustment Formulas

$$RD_T = \sum_{CC=1}^{CC=3} \left[\left(BRPC_{T-1}^{CG} - ARPC_{T-1}^{CC} \right) x \; ACUSTS_{T-1}^{CC} \right]$$

And

$$RDAF = \frac{RD}{FV}$$

Where the terms in the above equation have the following meanings:

$ACUSTS_{T-1}^{CC}$: The actual number of customers for the applicable Customer Class for the most recently completed Decoupling Year. Actual number of customers for each Decoupling Year shall be the average number monthly customers in that season, calculated by summing the number of billed customers in each month of the most recently completed Decoupling Year, and dividing by the number of months in that year.

$ARPC_{T-1}^{CC}$: The Actual Base Revenue Per Customer for the applicable Customer Class Group for the most recently completed Decoupling Year (T-1), as defined in Section i.

$BRPC_{T-1}^{CC}$: The Benchmark Base Revenue Per Customer for the applicable Customer Class Group as determined in accordance with Section i.2. for the most recently completed Decoupling Year (T-1).

cc	Customer Classes as defined in Section i.3.
RD	The Revenue Decoupling adjustment to revenues.
$RDAF_T$:	The Revenue Decoupling Adjustment Factor.
FV	Forecast sales volumes for the Billing Year.

1.0 Application of the RDAF to Customer Bills

The RDAF ($ per kWh) shall be truncated at the nearest one one-hundredth of a cent per kWh. The RDAF will be applied to the monthly tariff sales for each customer.

2.0 Information to be Filed with the Commission

Information pertaining to the RDAF will be filed annually with the Commission consistent with the filing requirements of all costs and revenue information included in the Tariff. Such information shall include:

1. The calculation of the applicable revenue decoupling revenue dollar adjustment for the Decoupling Year by Customer Class Group.
2. The calculation of the proposed decoupling rate per kWh for all firm rates to be applied in the Billing Year.
3. The calculation of the monthly Benchmark Base Revenue per Customer, to be utilized in the upcoming Decoupling Year. If distribution rates change during the Decoupling Year, the monthly Benchmark Base Revenue per Customer for the remaining months of the Decoupling Year will be revised and filed with the Commission.

39B. Property Tax Adjustment Mechanism (PTAM)

1. Purpose: The purpose of this provision is to establish a procedure that allows the Company, subject to the jurisdiction of the NHPUC, to recover the revenue shortfall (costs) associated with Actual municipal property taxes from the property tax bills received in the prior calendar year are compared to the amount of municipal property taxes. At the end of the corresponding April 1 through March 31 property tax year and any over- or under-recoveries are adjusted annually through the PTAM. The PTAM is based on a full reconciliation with monthly compounded interest for any over- or under-recoveries occurring in prior year(s). Interest is calculated at the prime rate, fixed on a quarterly basis and established as reported in the Wall Street Journal on the first business day of the month preceding the calendar quarter ("Prime Rate").

2. The PTAM Rate shall be applied to all rate classes. The PTAM Rate shall be filed with the Company's transmission charge filing and shall be determined annually by the Company and be subject to review and approval by the Commission.

3. Effective Date: On or before the first business day in September of each year, the Company shall file with the NHPUC for its consideration and approval, the Company's request for a change in the PTAM Rate applicable to all firm sales, delivery and transportation service throughput for the subsequent twelve-month period commencing with the calendar month of November.

4. Reconciliation Adjustment: At the end of the corresponding April 1 through March 31 property tax year and any over- or under-recoveries are adjusted annually through the PTAM. The PTAM is based on a full reconciliation with monthly compounded interest for any over- or under-recoveries occurring in prior year(s). Interest is calculated at the prime rate, fixed on a quarterly basis and established as reported in the Wall Street Journal on the first business day of the month preceding the calendar quarter ("Prime Rate").

40. Electricity Consumption Tax Charge

All Customers shall be obligated to pay the Electricity Consumption Tax Charge in accordance with New Hampshire Statute RSA Chapter 83-E, which may be revised from time to time, in addition to all other applicable rates and charges under this Tariff. The Electricity Consumption Tax Charge shall appear separately on all Customer bills. Any discounts provided for under a Special Contract shall not apply to the Electricity Consumption Tax Charge.

41. System Benefits Charge

All customers taking delivery service shall pay the System Benefits Charge as required by New Hampshire law and approved by the Commission. The System Benefits Charge shall recover the