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Matthew Ketschke
President

January 28, 2022

Hon. Michelle L. Phillips, Secretary
New York State Public Service Commission
Three Empire State Plaza
Albany, New York 12223

Dear Secretary Phillips:

New York State is leading the way to a clean energy future. By taking bold action through the Climate Leadership and Community Protection Act ("CLCPA") to reduce emissions and support disadvantaged communities, the State is building a sustainable energy future for all New Yorkers.

Con Edison shares the State's vision and is committed to making it a reality. To do that, we are proposing new electric and gas rate plans for January 2023 that will help fund investments to bring large-scale clean energy resources to our customers, reduce emissions, and facilitate increased electrification.

Over the next three years, our proposed electric and gas plans will support economic growth and development in New York City and Westchester County by investing more than $14 billion in the communities we serve, including disadvantaged communities. Our strategy of developing smart, multi-value projects, combined with our 200 years of experience lighting, heating, and powering New York, enables us to deliver cost-effective results.

Among other things, this rate filing includes:

- **The Reliable Clean City Projects** that will permit older, more polluting generators in New York City to retire and will help bring new, renewable power to our service territory

- **200 MW of new solar generation as part of a 1000 MW project** that will reduce bills for low-income customers, on top of our new capital investments to make it easier for our customers to own solar

- **Four new storage projects** that will enhance reliability, resilience, operational flexibility, and serve disadvantaged communities

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- **A portfolio of building electrification programs** that will reduce emissions by facilitating the transition away from natural gas and other fossil fuels and reduce the cost to customers to electrify their homes and businesses

- **A Selective Undergrounding Program** that will enhance reliability and resiliency by undergrounding sections of the overhead electric distribution system that are most vulnerable to storms and that includes consideration of disadvantaged communities

- **Electric system investments to prepare for extreme heat from climate change and increased demand from electrification**, including the new Gateway Park Area Substation

- **Projects to reduce methane emissions from our gas system**, including replacing leak prone mains and purchasing renewable and certified gas

As part of our clean energy commitment, we will also continue our unprecedented investments in energy efficiency, electric vehicles, demand response, and heat pumps. These clean energy investments will help the environment and lower customers' bills. For example, we will continue our investments to:

- **Add nearly 20,000 new electric vehicle chargers** by 2025

- **Encourage heat pumps** as an alternative to gas and other fossil fuel heating

Over the next three years, we estimate that our clean energy investments will save approximately 2.4 million metric tons of carbon dioxide, equivalent to taking more than 500,000 cars off the road for a year.

As we push towards a clean energy future, we will keep our relentless focus on safety and reliability. The Commission recently emphasized that "failure to maintain safe and adequate electric and gas systems throughout the state would undermine the intent of the CLCPA."[1] We agree. Safety and reliability have been in our DNA since Thomas Edison built the first underground electric grid in 1882. We will keep making the equipment and maintenance investments required to keep our systems safe and reliable into the future. This includes continuing to invest in cybersecurity to stay ahead of current and evolving threats.

We recognize that the future will involve responding to more frequent and severe weather. The six worst storms in the Company's long history, as measured by the number of customer outages, have all occurred since 2010. As Winter Storm Uri in Texas, last year's heat wave in the Northwest, and Tropical Storm Ida here in New York demonstrate, extreme weather makes safe, reliable, and resilient energy systems even more important.

[1] Case 20-E-0380 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements (Jan. 20, 2022) at 80.

Our proposed electric rate plan includes investments to make our infrastructure more resilient, including undergrounding the electric distribution lines that serve customers most affected by storms and increasing our system's ability to withstand the extreme heat that will come from climate change. Our resilience investments mean that fewer customers will lose service when severe weather strikes, and that we can restore service faster to those that do.

As our customers rely more and more on electricity to power their lives, they can count on us to restore service as soon as possible after a storm. Our proposed electric rate plan continues to invest in storm preparation and includes provisions for bringing in the extra crews we need to get the power back on as soon as possible.

Because of our commitment to clean energy, our proposed gas rate plan is not a "business-as-usual" filing. First, our gas investments, such as our significant investments in replacing leak-prone mains, installing remote natural gas detectors, and complying with federally required gas transmission main replacement, are to reduce methane emissions and make our system safer, not expand it.[2] Over the next three years, approximately 85 percent of our gas system investment will be devoted to making the system safer. Second, we are the first gas utility in New York State to propose eliminating economic assistance not required by law for new gas customers by increasing the amount of new pipe that they would have to pay for directly. Finally, we are increasing our electrification education programs and requiring all prospective gas customers to certify that we have informed them about clean energy alternatives and the State's clean energy policy before we provide them with new gas service.

Our customers can also rely on us to provide excellent customer service and to assist them with their energy choices. Our proposed rate plans keep investing in our customer education and customer service systems. For example, this rate filing includes:

- **Completing our new Customer Service System** that will improve billing and customer service

- **Finishing our Smart Meter installation** so that all customers can make informed choices about how and when to use energy and we can see and respond to outages faster

- **A new Customer Relationship Management System** that will allow us to better tailor solutions to customer needs by gathering interaction data in a single place

- **New tools to facilitate customer energy choice**, including guidance on clean energy options

[2] The gas revenue requirement includes the effect of a proposal to modestly decrease gas service line depreciation lives by five years. While the exact path of decarbonization is uncertain, all forecasted paths show decreased natural gas usage. We believe that it is essential to begin now to manage this transition and the cost for future customers.

- **Enhanced communication and education efforts for low-income and at-risk customers**, including improvements for non-English speakers

We know our customers trust us to be good stewards of their hard-earned money. We take that responsibility seriously and strive for efficiency in all our operations while providing products and services that our customers value. As part of our ongoing commitment to affordability, our proposed rate plans also include a discount program for small business customers, a solar program for low-income customers, and increased energy efficiency programs for low-and moderate-income customers.

We have been consistently recognized as a leader in clean energy *and* reliability, so we know what it takes to deliver safe, clean, reliable, and resilient energy to our customers. Our proposed rate plans are the path forward.

A. <u>Electric and Gas Increases</u>

Our proposed rate plans are designed to fund the investments necessary for a safe and reliable clean energy future, including the investments summarized earlier, and our operating expenses, like local property taxes.

To meet these funding requirements, our proposed plans request authority to collect approximately $1.2 billion more in electric revenue and approximately $500 million more in gas revenue. The electric revenue requirement translates to an overall electric customer bill increase of 11.2 percent.[3] The gas revenue requirement translates to an overall gas customer bill increase of 18.2 percent.[4]

More than half of the overall electric bill increase, and more than one-third of the overall gas bill increase, is attributable to three categories: local property taxes, deferred costs, and an updated sales forecast that appears as an increase but in reality does not have a bill impact because these costs have already been incorporated into bills through the existing revenue decoupling mechanism.[5] In addition, much of the spending in our proposed plans either has been previously authorized by the Commission or is required to comply with gas safety regulations.

[3] The delivery charge increase, which is a component of the overall customer bill, is 17.6 percent. The calculation of the overall customer bill increase percentage includes estimates of electric supply costs for Con Edison retail access customers and New York Power Authority customers.

[4] The delivery charge increase, which is a component of the overall customer bill, is 28.1 percent. The calculation of the overall customer bill increase percentage includes estimates of gas supply costs for Con Edison retail access customers.

[5] Less than 40 percent of the increase is attributable to the capital required to fund our $4.7 billion new capital investment and the Company's proposed increase in its overall equity return to reflect capital market conditions for raising money to fund needed investments.

1. Property Taxes

Property taxes, around 90 percent of which are paid to New York City, will be $2.5 billion for electric and gas for 2023. They account for approximately $180 million of our proposed electric increase and $75 million of our proposed gas increase. Property taxes alone account for an overall electric bill increase of almost two percent and an overall gas bill increase of just under three percent.[6]

We make every effort to reduce the property taxes that our customers bear, including contesting our tax assessments. But final property tax decisions are ultimately made by the municipalities where we provide service.

2. Deferred Costs

As required by the current rate plan, we have deferred charging customers certain costs of providing service, including approximately $50 million spent preparing for and responding to more frequent and severe storms[7] and $20 million spent performing new gas service line inspections in compliance with recent governmental directives. In addition, current electric rates were reduced because of the 2017 federal Tax Cut and Jobs Act. A portion of those tax benefits will have been fully passed to electric customers by 2023, resulting in an approximately $130 million increase in the electric revenue requirement. In total, these and other items in this category account for an overall electric bill increase of approximately 1.9 percent and an overall gas bill increase of approximately 0.5 percent.

3. Updated Sales Forecasts

Our electric and gas revenue requirements are converted to rates by allocating them across expected sales volumes. Actual electric and gas sales, however, have been lower than the forecasts used to set current rates. This causes revenue shortfalls that customers currently pay through a revenue decoupling mechanism. The Commission has required revenue decoupling since 2007[8] to encourage utilities to promote energy efficiency and other conservation measures without the disincentive of losing sales.

Our proposed electric and gas revenue requirements use revised sales forecasts that are lower than the sales forecasts underlying current rates. On paper, this has the effect of increasing the electric revenue requirement by approximately $260 million and the overall electric bill by approximately 2.5 percent and the gas revenue requirement by approximately $80 million and the overall gas bill by approximately 2.9 percent.

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[6] To avoid situations where the property tax estimates used to set rates fall short of actual property taxes and result in large deferrals to be collected from customers in the future, we are proposing a new rate adjustment mechanism that would recover such incremental property tax costs as incurred.

[7] As with property taxes, we propose a rate adjustment mechanism to recover during the rate plan period storm preparation and response costs that exceed what is in rates.

[8] Case 03-E-0640 et al., *Proceeding on Motion of the Commission to Investigate Potential Electric Delivery Rate Disincentives Against the Promotion of Energy Efficiency, Renewable Technologies and Distributed Generation*, Order Requiring Proposals For Revenue Decoupling Mechanisms (Apr. 20, 2007).

From a practical standpoint, however, these updated sales forecasts do not have a bill impact because these costs have already been incorporated into customer bills through the existing revenue decoupling mechanism.

4. Authorized and Required Spending

Our electric and gas revenue requirements include spending that either the Commission has already authorized or that is required to comply with gas safety regulations. For example, our electric revenue requirement includes the costs of the Reliable Clean City Projects and our energy efficiency and electric vehicle charging programs. Our gas revenue requirement includes approximately $100 million to comply with recent federal gas safety rules and approximately $36 million in new operations and maintenance costs to comply with recent service line inspection requirements.

B. Mitigation of Requested Increase

To mitigate our requested electric and gas increase, we develop smart, cost effective investments. For example, where possible we design electric system projects to facilitate clean energy while solving reliability needs. Such multi-value projects, which we are in the best position to design, provide our customers with high value. We have also taken a harder look at our gas investments due to potential electrification and are proposing to reduce our annual gas leak prone pipe replacement commitment by a modest amount without affecting safety.

We have also changed the way we work. During our current rate plan, we are engaging in a focused effort to identify opportunities for efficiency that will save customers over $150 million, including from our significant investment in automated metering infrastructure. These efficiencies are now part of how we do business and these previously achieved ongoing and expected savings helped to reduce our current request.

In addition, we are exploring opportunities to receive funds authorized by the 2021 federal Infrastructure Investment and Jobs Act to help fund our required investments and reduce the costs we need to collect from customers. Finally, we participate in proceedings at the Federal Energy Regulatory Commission and advocate for reasonable market rules at the New York Independent System Operator to reduce supply costs that we are required to pass on to customers.

C. Affordability

We are committed to affordability for our customers who require assistance. We support and provide discounts, which have recently increased significantly, to our low-income customers, and which will mitigate the increase. We are also aggressively implementing our energy efficiency programs for low-and moderate-income customers. In addition, we are assisting residential and small business customers facing financial hardship. Finally, we note that with respect to impact on our residential customers, typical annual residential consumption has fallen by approximately seven percent since 2013.

We are also proposing to procure and own up to 1,000 MW of utility-scale solar generation facilities between 2024 and 2034 and to use the revenues to further increase our low-income bill discount. We forecast that this plan, when fully implemented, could provide an approximate $15 per month electric bill credit and connect low-income customers to the benefits of renewable energy.

Finally, we are proposing a discount program for small businesses, which have been particularly hard hit by the COVID-19 economic downturn. While we expect based on current economic forecasts that the economy will have returned to normal by the time our proposed rate plans take effect in January 2023, this program will provide needed assistance to small businesses that may require aid after the recovery begins.

D. Proposed Rate Term

We are proposing one-year electric and gas rate plans but intend to explore multi-year rate plans in settlement discussions with the Department of Public Service and other interested parties. Multi-year rate plans benefit customers by providing rate certainty for the duration of the plan and by facilitating implementation of the Company's investments.

E. Revised Tariff Leaves, Effective Date and Public Notice

Our proposed rate plans require changes to our electric and gas tariffs, including increases to the charges for electric and gas service. Included as appendices to this letter are revised Tariff leaves, descriptions of changes, and revenue impacts as follows:

Appendix A – List of Revised Electric Tariff Leaves
Appendix B – List of Revised PASNY Tariff Leaves
Appendix C – List of Revised Gas Tariff Leaves
Appendix D – Proposed Changes to the Electric and PASNY Tariffs
Appendix E – Proposed Changes to the Gas Tariff
Appendix F – Electric Revenue Impacts
Appendix G – PASNY Revenue Impacts
Appendix H – Gas Revenue Impacts
Appendix I – Typical Residential Customer Bill Impacts

The revised Tariff leaves are issued as of January 28, 2022, to become effective February 27, 2022. We respectfully request that the Commission suspend the effective date and, unless the Company subsequently requests otherwise, approve and make the proposed Tariff leaves effective on and as of January 1, 2023.

The Company will provide for public notice of the Tariff changes proposed in this filing by means of newspaper publication once a week for four consecutive weeks prior to February 27, 2022. In addition, with this filing we have included draft Notices of Proposed Rulemaking in the form required by the State Administrative Procedure Act and the Commission's form regarding consent to receive electronic-only service of Commission orders.

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We know that the transition to a clean energy future is a big job. But we are a Company that gets big jobs done. We are privileged to serve New York City and Westchester County and we look forward to engaging with our stakeholders on our plans to achieve the clean and resilient energy future we all want.

Very truly yours,

CONSOLIDATED EDISON COMPANY OF NEW YORK

Matthew Ketschke
President

PSC No. 10 - Electricity: List of Revised Electric Tariff Leaves

Leaf No.	Revision No.	Superseding Revision No.	Leaf No.	Revision No.	Superseding Revision No.
3	6	5	166.4	0	
6	17	16	166.5	0	
7	9	8	166.6	0	
17	3	2	166.7	0	
33	1	0	166.8	0	
36.2	0		166.9	0	
37	4	1	166.10	0	
37.1	0		166.11	0	
45	1	0	167	10	9
56	4	3	167.1	6	5
61	5	4	170	4	3
63.1	6	5	171	8	7
64	3	2	177	24	23
79.1	0		181	15	14
79.2	0		193	6	5
79.3	0		195	6	5
79.4	0		196	6	5
79.5	0		197	5	4
79.6	0		198	9	8
79.7	0		199	7	6
95	11	10	200	7	6
97	8	7	201	8	7
119	12	11	213.1	3	2
121	8	7	234	4	3
122	8	7	235	2	1
124	1	0	236	3	2
125	1	0	237	2	1
126	8	7	238	3	2
129	1	0	239	8	7
146	3	2	240	8	7
153	4	3	242	9	8
154	7	6	243	9	8
155	3	2	243.1	6	5
156	2	1	243.2	6	5
157	8	7	243.3	6	5
157.0.1	2	1	243.4	6	5
157.1	6	5	243.5	6	5
157.1.1	4	3	243.6	6	5
157.2	8	7	243.7	6	5
157.2.1	2	1	243.8	6	5
157.3	6	5	243.9	6	5
157.4	16	15	243.10	6	5
157.5	2	1	253	8	7
157.6	1	0	253.9	2	1
158	3	2	268	13	12
159	3	2	270	10	9
160	5	4	272	11	10
162	12	11	273	7	6
162.2	5	4	274	7	6
164	8	7	281.1	2	1
166.2	0		292	6	5
166.3	0		293	1	0

PSC No. 10 - Electricity: List of Revised Electric Tariff Leaves

Leaf No.	Revision No.	Superseding Revision No.
294	1	0
295	3	2
296	3	2
297	4	3
298	1	0
299	1	0
300	2	1
301	6	5
320	1	0
327.3	7	6
327.4	7	6
327.5	7	6
327.5.1	6	5
327.10	7	6
327.14	6	5
329	6	5
330.1	7	5
331	4	3
335	5	4
336	9	8
337	12	11
339	4	3
340	3	2
341	5	4
342	1	0
343	15	14
343.1	12	11
344	9	8
346	4	2
347	3	1
351	19	18
352	10	9
359.1	1	0
360	5	4
384.1	6	5
385	11	10
385.0.1	6	5
387	4	3
388	16	15
389	16	15
389.1	14	13
389.2	3	2
396	2	1
397	16	15
398	15	14
399	3	2
406	15	14
408	15	14
409	15	14
410	15	14
411	4	3

Leaf No.	Revision No.	Superseding Revision No.
416	15	14
432	15	14
434	2	1
435	15	14
437	15	14
438	15	14
439	15	14
440	4	3
444	2	1
445	16	15
448	2	1
449	15	14
451	15	14
452	15	14
453	15	14
453.1	12	11
454	4	3
458	5	4
459	8	7
459.0.2	2	1
459.3	6	5
463	16	15
465	4	3
466	4	1
467	4	3
468	2	1
469	3	2
470	4	3
472	4	3
476	4	3
477	5	4
479	15	14
480	15	14
482	2	1
483	15	14
485	15	14
486	15	14
487	15	14
488	15	14
490	2	1
492	2	1
495	15	14
496	16	15
497	4	3

PSC No. 12 - Electricity: List of Revised PASNY Tariff Leaves

Leaf No.	Revision No.	Superseding Revision No.
4	15	14
5	15	14
6	15	14
7	16	15
8	16	15
9	15	14
10	13	12
11	3	2
13	11	10
17	4	3
17.1	6	5
19	3	2
20	2	1
22	13	12
24	3	1
25	6	5
26	10	9
26.1	8	7
26.2	3	2
26.4	6	5
26.5	1	0
26.6	0	

Appendix C

PSC No. 9 - Gas: List of Revised Tariff Leaves

Leaf No.	Revision No.	Superseding Revision No.	Leaf No.	Revision No.	Superseding Revision No.	Leaf No.	Revision No.	Superseding Revision No.
4	16	15	154.13	3	2	235.1	0	
5	22	21	154.14	4	3	240	34	33
6	15	14	154.15	4	3	241	7	6
12	7	6	154.16	3	2	243	26	25
13	5	4	154.17	7	6	251	11	10
30	3	2	154.18	28	27	255	26	25
31	4	3	154.19	4	3	259	13	12
33	1	0	154.24	28	27	261	5	4
34	2	1	154.25	25	24	264	14	13
35	2	1	155	20	19	269	28	27
44	3	2	156	21	20	274	17	16
48	3	2	157.1	16	15	275	12	11
76.1	12	11	158	17	16	279	10	9
77	4	3	166.2	16	15	300.3	13	12
78	1	0	166.3	2	1	303.3	2	1
85	3	2	167.1	8	7	316	11	10
87	7	6	171	10	9	316.1	10	9
89	5	4	173	9	8	317	10	9
117	10	9	176	6	5	318	6	5
127	7	6	177	14	13	326	10	9
128	14	13	178	19	18	326.1	8	7
129	7	6	178.1	15	14	327	10	9
130	7	6	178.2	6	5	329	8	7
148	3	2	180	18	17	330	10	9
149	3	2	181	22	21	331	12	11
150	1	0	181.1	9	8	332	19	18
151	1	0	181.2	10	9	333	6	5
152	27	26	183	22	21	334	6	5
153	1	0	183.1	23	22	341.1	10	9
154	2	1	183.2	16	15	342	10	9
154.6	24	23	183.6	4	3	349	33	32
154.7	11	10	183.7	0		378	6	5
154.8	24	23	228	35	34	385	6	5
154.9	30	29	230	28	27	389.3	7	6
154.10	7	6	232	3	2	397.1	7	6
154.11	8	7	234	22	21	397.2	10	9
154.12	3	2	235	13	12	397.3	11	10

Proposed Changes to the Electric and PASNY Tariffs

Section	Leaf #s	Description of Tariff Change	Testimony Panel
PSC No. 10 - Electricity			
SC Rate Changes			
SC 1 Rate I	388	Updated rates.	ERP
SC 1 Rate II-VTOD rates and Spec Prov D rates	389	Updated rates.	ERP
SC 1 Rate III - VTOD (also applicable to Spec Prov F customers)	389.1	Updated rates.	ERP
SC 1 Rate IV - Optional Demand Based Rate	389.2	Updated rates.	ERP
SC 2 Rates I and II	397, 398	Updated rates.	ERP
SC 5 Rates I, II, III, and IV	406, 408, 409, 410	Updated rates.	ERP
SC 6	416	Updated rates.	ERP
SC 8 Rates I, II, III, IV and V	432, 435, 437, 438, 439	Updated rates.	ERP
SC 9 Rates I, II and III	445, 449, 451	Updated rates.	ERP
SC 9 Rates IV and V, incl. station use	452, 453, 453.1	Updated rates.	ERP
SC 11	463	Updated rates.	ERP
SC 12 Rates I and II (incl Rt I energy only)	479, 480, 483	Updated rates.	ERP
SC 12 Rates III, IV and V (incl III energy only)	485, 486, 487, 488	Updated rates.	ERP
SC 13 Rates I and II	495, 496	Updated rates.	ERP
Other Rate Changes			
GR 10.11 - Reactive Power Demand Charge	95	Updated rates.	ERP
Rider D	181	Updated rates.	ERP
Rider Q - Option B CRSP and DLRP rates	242- 243.10	Updated rates.	ERP
Riders Z and AA - IPP rates	327.3, 327.4, 327.5, 327.5.1, 327.10	Updated rates.	ERP
Rider AB - Smart Home Rate	327.14	Updated rates.	ERP
GR 25.3 - MFC	335	Updated rates.	ERP
SC 9 Spec Prov G (RNY)	459.0.2	Updated rate.	ERP
GR 21.1 - Continuity of Supply	171	Updated spoilage compensation amounts.	ERP
GR 26.2(3) - RDM targets	351	Indicated that RDM targets are "to be determined."	ERP
GR 28 - Transition Adjustment for Competitive Services	360	Updated targets.	ERP

Proposed Changes to the Electric and PASNY Tariffs

Section	Leaf #s	Description of Tariff Change	Testimony Panel
Uncollectible	146, 336, 344	Uncollectibles experience to be based on the 12-months ended September (instead of November).	ERP
GR 25.1- MSC factor of adjustment	329	Updated Factor of Adjustment for Losses.	ERP
SC 1 Rate IV	389 .2	Eliminated eligibility requirements making SC 1 Rate IV an optional rate available to all SC 1 customers.	ERP
SCs 1, 2, and 9	387, 396, 444	Clarified that SC 2 and SC 9 are SCs intended for which no other service classifications are specifically provided.	ERP
	n/a	Include Standby rates in RDM effective January 1, 2024.	ERP
Tariff Changes			
Rider J - BIR Changes			
Rider J - Business Incentive Rates ("BIR")	193, 195, 196, 197, 198, 199, 200, 201	Added a new COVID-19 BIR component and MAC recovery.	ERP
GR 26.1 - MAC	343	Added new component 36 to recover amounts associated with COVID-19 BIR rate reductions.	
Rider J - Business Incentive Rates ("BIR")	193	SCs 2 and 9 Special Provision (C) is not applicable to customers served under Rider J.	ERP
AMI Tariff Changes			
Standby and SC 11 - Buy Back provisions	162.2, 166.5, 167, 240, 477	Eliminated requirement for customer to provide communications for Output Meters.	ERP
General Rule 20.4 - Billing under Standby Service Rates	61, 166.9	Deleted requirement for customer to provide and maintain communication services and deleted monthly communications service credit.	ERP
General Rule 20.4 - Billing under Standby Service Rates	166.8, 166.9	Modified Standby Offset interval meter readings to be based on 15-minute interval to each metered interval.	ERP
Rider R - Net Metering and Value Stack Tariff for Customer-Generators	253	Added an option for Rider R customers to close an account on the date of request for customers with communicating AMI meters.	ERP
SCs 2 and 12	399, 490	Deleted the provision that a demand meter will be installed if customer uses over 10 kW or 6,000 kWh over two months	ERP
SCs 5, 8, 9, 11, and 13	411, 440, 454, 472, 497	Deleted the installation of demand meter provisions.	ERP
SC 12 - Multiple Dwelling Space Heating	492	Established SC 12 energy only/demand thresholds.	ERP
GR 6.10 - AMR/AMI Meter Opt-out	63.1	Residential customers who are required to have an Interval Meter cannot opt-out of AMI.	ERP
Distributed Generation Changes			

Proposed Changes to the Electric and PASNY Tariffs

Section	Leaf #s	Description of Tariff Change	Testimony Panel
General Rule 8.4	79.1-79.7, 153-160, 465-470	Combined Standby and SC 11 interconnection rules and moved to new General Rule 8.4.	ERP
General Rule 20.4	157-157.6, 166.2-166.11, 164, 167.1, 170, 239, 384.1, 385, 385.0.1	Moved Standby Offset and export to another service connection provisions to Billing under Standby Service Rates section, and updated all references.	ERP
General Rule 20.3	162	Deleted the 30-day requirement for customers with Designated Technologies electing to be billed under Standby Service rates.	ERP
SC 11	476, 477	Deleted the option to export to NYISO under SC 11.	ERP
Standby provisions	79.1, 166.2, 166.4, 384.1	Removed the 20 MW upper limit for generating facility interconnections	ERP
Housekeeping Changes			
Update table of contents to include EV Make-Ready Surcharge	7, 337	Updated table of contents and list of delivery surcharges to include EV Make-Ready Surcharge	ERP
General Rule 2 - Definitions	17	Clarified the definition for Pure Base Revenue.	ERP
General Rule 5.5 - Underground Facilities	45	Added an option for the Company to elect to provide underground facilities.	ERP
General Rule 5.6 - Transformers and Associated Equipment	56	Deleted specific language related to flood protection requirements that are included in Company specifications.	ERP
General Rule 17.6 - Meter Upgrades and Purchases	129	Deleted the obsolete provision related to customer-owned meters.	ERP
Rider T	268	Delete obsolete provisions that were only applicable for 2017 and 2018.	ERP
Rider T	270, 272, 273	Deleted obsolete provisions that were applicable only during the 2020 capability period.	ERP
Rider T	274	Deleted ”/or” from the sentence "DRV and and/or LSRV value compensation."	ERP
GR 26.1 - MAC	339, 342, 343, 343.1, 346, 347, 459	Deleted or revised certain MAC components.	ERP
26.10 EV Make-Ready Surcharge	359.1	Added time periods to clarify the EV Make-Ready Surcharge applicable to Rate II of SC 5 and Rate II and Rate III of SCs 8, 9, and 12.	ERP
SCs 8, 9, and 12	434, 448, 482	Removed obsolete provision for thermal storage customers.	ERP
SC 9 Special Provision D	97, 200, 320, 330.1, 458, 459.3	Removed the expired SC 9 Special Provision D heating discounts.	ERP
GR 5.2.4 - Excess Distribution Facilities	36.2	Added General Rule - 5.2.5 Permits that was erroneously deleted.	
Changes Described in Other Testimonies			
Rule 17.3 - Special Services Performed by the Company at a Charge	126	Updated percentages for handling costs and corporate overheads for costs associated with Special Services.	Accounting

Proposed Changes to the Electric and PASNY Tariffs

Section	Leaf #s	Description of Tariff Change	Testimony Panel
GR 26.1 - MAC	339	Added new component 10 to reconcile carrying charges associated with interference costs.	Accounting & MISP
GR 26.1 - MAC	339	Added new component 11 to reconcile storm costs.	Accounting & SRR
GR 26.1 - MAC	341	Added new component 20 to reconcile costs related to deferred late payment fees and other fees originally associated with customer non-payment.	Accounting
GR 26.1 - MAC	341	Added new component 21 to reconcile uncollectible bill expenses and non-Credit and Collections portion of the POR Discount reconciliation.	Accounting
GR 26.1 - MAC	341	Added new component 23 to reconcile property taxes.	Accounting
GR 16.1 - Charge for Replacing a Damaged Meter	121	Updated the Damaged AMI meter fee.	EIOP
GR 16 - Other Charges	121	Updated the charge for re-inspection.	EIOP
GR 17.1 - Special Services at Stipulated Rates	122	Updated charges for hi-pot test, Megger test, dielectric fluid testing.	EIOP
General Rule 7.1 – Customer Wiring and Equipment	64	Established a Company requirement to furnish and install wiring and equipment for customers in the Selective Undergrounding Program.	EIOP
GR 5.2.8 - Street or Sidewalk Service	33, 37, 37.1, 124, 125	Added new Street or Sidewalk Services provision and conforming changes.	EIOP
GR 15.2 - Reconnection Charge	119	Continued waiver of the Reconnection Charge for Low Income Customers. Changed per rate-year cap on waiver amount.	Customer Ops
GR 26.2(4) - Low Income Program Costs	352	Changed Low Income Program Fund for the rate year and indicated that the low-income program will continue beyond December 31, 2023 contingent on the continuation of full cost recovery.	Customer Ops
Riders P, V, and W	6, 177, 213.1, 234, 235, 236, 237, 238, 253.9, 281.1, 292, 293, 294, 295, 296, 297, 298, 299, 300, 301, 331, 340, 341	Deleted Riders P, V, and W and all references.	CES
GR 5.2.4 - Excess Distribution Facilities	36.2	Added a new provision, Distributed Energy Resources Make Ready Program for Disadvantaged Communities and Low-Income Customers.	CES
n/a	n/a	Cost recovery associated with Renewable Low Income Bill Credit in 2024	CES
PSC No. 12 - Electricity (PASNY)			
SC Rate Changes			
Rate I	4	Updated rates.	ERP

Proposed Changes to the Electric and PASNY Tariffs

Section	Leaf #s	Description of Tariff Change	Testimony Panel
Street lights and FA	5	Updated rates.	ERP
Rate II	6	Updated rates.	ERP
Rate III, inc station use rate	7	Updated rates.	ERP
Rate IV, inc station use rate	8, 9	Updated rates.	ERP
Other Rate Changes			
Reactive Power Charge	10	Updated rate.	ERP
Tariff changes:			
Rate I	4, 11	Clarified rules for transferring customers between energy only rates and both energy and demand rates.	ERP
Determination of Billable Demand	11	Deleted requirement that a demand meter will be installed if customer uses over 10 kW or 6,000 kWh over two months.	ERP
Communication metering credit	13	Deleted the requirement for the customer to provide and maintain communication service and deleted monthly communications service credit.	ERP
Standby Service and Standby Service Rates	17, 17.1	Updated references for Standby Offset and export to another service connection.	
Standby Service and Standby Service Rates	17.1	Corrected indentation in last paragraph.	ERP
Standby and Buy Back provisions	17.1	Eliminated requirement for customer to provide communications for Output Meters	ERP
Transition Adjustment for Metering Services	20	Removed the obsolete Transition Adjustment for Metering Services	
Additional Delivery Charges and Adjustments	22	Indicated that RDM targets are "to be determined."	ERP
Additional Delivery Charges and Adjustments	22	Changed Low Income Program Fund for the rate-year and indicated that the low-income program will continue beyond December 31, 2023 contingent on the continuation of full cost recovery.	Customer Ops
Additional Delivery Charges and Adjustments	19, 24, 25, 26, 26.1, 26.2, 26.5	Deleted or revised certain adjustments.	ERP
Other Charges and Adjustments	26.1	Earning Adjustment Mechanisms to be determined based on the PASNY Allocation.	CES
Other Charges and Adjustments	26.4, 26.5	Revised component 17 to include late payment fee recovery starting in 2023.	Accounting
Other Charges and Adjustments	26.5	Added new component 18 to reconcile storm costs.	Accounting & SRR
Other Charges and Adjustments	26.5	Added new component 19 to reconcile carrying charges associated with interference costs.	Accounting & MISP
Other Charges and Adjustments	26.5	Added new component 20 to reconcile property taxes.	Accounting
Other Charges and Adjustments	26.6	Added new component 21 to reconcile uncollectible bill expenses and non-Credit and Collections of the POR Discount reconciliation.	Accounting
Other Charges and Adjustments	26.6	Added new component 22 to recover amounts associated with COVID-19 BIR rate reductions.	ERP

Proposed Changes to the Electric and PASNY Tariffs

Section	Leaf #s	Description of Tariff Change	Testimony Panel

Legend

ERP - Electric Rate Panel
EIOP - Electric Infrastructure & Operations Panel
CES - Customer Energy Solutions
MISP - Municipal Infrastructure Support Panel
GR - General Rule
SRR - Storm Response and Resilience Panel

Proposed Changes to the Gas Tariff

PSC No. 9 - Gas

Section	Leaf #s	Description of Tariff Change	Testimony Panel
SC Rate Changes			
SC 1	228	Updated rates.	GRP
SC 2	230, 234	Updated rates.	GRP
SC 3	240, 243	Updated rates.	GRP
SC 9	269	Updated rates.	GRP
SC 12	331	Updated rates.	GRP
SC 13	349	Updated rates.	GRP
Other Rate Changes:			
GI VI. (E) - Rider D - Excelsior Jobs Program	128	Updated discounts	GRP
Rider H - Distributed Generation Rates	154.6, 154.8, 154.9	Updated rates.	GRP
Rider J - Residential Distributed Generation	154.24, 154.25	Updated rates.	GRP
GI IX.8 - Merchant Function Charge (MFC)	178.2	Updated the per therm supply-related charge and credit and collection-related rates that will be in effect	GRP
Tariff Changes:			
General Changes			
GI II., GI III.14 (B) & (E), SC 9, SC20	12, 13, 85, 89, 259, 261, 316, 385, 389.3	Added language throughout the tariff to include Local RNG Production	GIOSP
GI III.3 B	30	Modified the main and service allotment for residential heating customers	GIOSP
GI III.3(B)(3)(b)	30, 31	Removed the 100' main entitlement aggregation language	GIOSP
GI III.3.(C).(1) &(2)	33, 34, 35	Removed the revenue test	GIOSP
GI III.5(C) 3 ii (a) & (b)	44	Updated the Inside Piping Survey/Inspection Fees	GIOSP
GI III.8(C)(2)	48	Modified no access costs	GIOSP
GI III.8	77, 78	Added Damaged Meter Fee	GIOSP
GI III(14)(E)	89	Added additional pipelines to the weighted market price of gas calculation	GRP
GI IV.2 (B) & (F)	117	Updated percentages for handling costs and corporate overheads for costs associated with special services	Accounting
VI (D) Rate II (3), VI (E); SC 2; SC 3	129, 154.25, 235, 243	Added the WNA to list of charges applicable to various rates	GRP
GI VI (D) Rate II (3), VI (E); SC 2; SC 3	129, 235, 243	Added WNA to rates under Rider J	GRP

Proposed Changes to the Gas Tariff

Section	Leaf #s	Description of Tariff Change	Testimony Panel
GI VI (H) (1), SC 9, SC 12, SC 20	154.10	Removed requirement for Rider H customers to have Interval Metering	GRP
GI VI (H) (1), SC 9, SC 12, SC 20	154.10, 154.11, 317, 318, 326.1, 342, 397.1	Removed references to phone lines	GRP
GI VI (H) (1) SC9, SC 12	154.11, 326.1, 342	Added exemption language from fee for customers with AMI	GRP
GI VII.(B)(2), GI IX.4	176	Added Reconciliation of Interference Costs adjustment	Accounting
GI VII.(B)(2), GI IX.6	177	Added Unbilled Fees Adjustment	Accounting
GI IX.7	178.1	Removed reference to Transition Adjustment for Competitive Services	GRP
GI IX.10	180	Updated the new low income funding level in rates	GRP
GI IX.14	181.1	Changed method for calculating interest on the RDM Adjustment	GRP
GI IX.14	181.2	Changed RDM Targets to TBD	GRP
GI IX.19	183.1	Update the Other Non-Recurring Adjustments to remove the reference to prior case	GRP
GI VII.(B)(2), GI IX.28	183.6	Removed the Pipeline Safety Acts Surcharge and added Surcharge for Gas Safety Compliance Adjustment	GIOSP
GI VII.(B)(2), GI IX.31	183.6	Added Reconciliation of Property Taxes adjustment	Accounting
GI VII.(B)(2), GI IX.32	183.7	Added Uncollectible Bill Expense Adjustment	Accounting
SC 2 (2), SC 3 (2)	232, 241	Added language to the reconciliation of the minimum charge	GRP
SC 12	342	Added exemption language for customers with AMI	GRP
SC 20	397.2	Modified timeline for UB recovery	GRP
Housekeeping			
Table of Contents	4, 5, 6	Added new Special Adjustments and eliminated obsolete Special Adjustments	GRP
GI III.8 V	76.1	Modified notification language regarding reconnection charges	GRP
GI III (14)(C)&(D)(a), SC9(B)(2)&(D), SC 12 Table of Contents & SC 12 (A)	87, 264, 316.1, 327, 329, 330, 341.1	Eliminated references to SC 12 Interruptible Temperature Control Option customers	GRP
GI VI. - Rider G	127, 148, 149, 150, 151, 152, 153, 154, 166.3, 171,173,178, 251, 269, 300.3, 326	Removed Rider G and references	GRP
GI VI - Rider I	127, 154.12, 154.11, 154.13, 154.14, 154.15, 154.16, 154.17, 154.18, 154.19, 166.3, 171,173,178, 251, 269, 300.3, 326	Removed Rider I and references	GRP
GI VI (E), (F)(3), (D)RI(3), (D)RII(3); GI VIII (C), GI IX (17), SC1, SC2, SC3, SC9 TOC, SC9 (J)(12), SC13	129, 154.7, 154.24, 154.25, 167.1, 183, 228, 235, 243, 255, 300.3, 303.3, 349	Eliminated references to the Tax Sur-Credit	GRP
GI VI (A), (D) Rate I (5), (D) Rate II (5)	130, 154.24, 154.25	Clarified eligibility of Rider J customers under Rider E	GRP
GI VII.(B) and GI VII.(b)(2) MRA	155, 166.2, 166.3	Added new components to the list of MRA items and eliminated obsolete components	GRP
GI VII.(B)(2), GI IX.4	158, 176	Removed Transition Surcharge for Capacity Costs	GRP
GI VII.(B)(2), GI IX.6	158, 177, 178, 255, 279	Removed Load Following Charge and associated references in the tariff	GRP
GI IX.14	181.2	Changed RDM Targets to TBD	GRP
GI VII.(B)(2), GI IX.31	183.6	Removed Manhattan Transmission Project Surcharge	GRP

Proposed Changes to the Gas Tariff

Section	Leaf #s	Description of Tariff Change	Testimony Panel
SC 2, SC 2 (D) (1)-(5)	230, 235, 235.1	Added exemptions to the SC2 ratio calculation	GRP
SC9(B), SC 12 (A)(1)	274, 332	Eliminated references to the annual interruptible reconciliation of SC12, Interruptible Rate 1	GRP
SC9(C), SC12(B)	275, 333, 334	Eliminated rates no longer being offered SC12 Rate 2	GRP
SC12	332, 333	Modified language to the off-peak firm commodity rate	GRP
SC 13	349	Added language to penalty rate	GRP
SC 20 (D)(2)(a)	378	Clarified the exclusion days for cost of gas for the cashout charge	GRP
SC 20 (P)	397.3	Removed obsolete language related the Credit and Collections component of the POR Discount Percentage	GRP

Legend:

GRP	Gas Rate Panel
GIOSP	Gas Infrastructure, Operations, and Supply Panel
Accounting	Accounting Panel
GI	General Information

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Estimated Effect on Con Edison Conventional and TOD Customers' Bills and Revenue
Resulting from the Application of Proposed Conventional and TOD Rates and Charges
Based on Sales and Revenues for the Twelve Months Ended December 31, 2019

Con Edison Service Classification -		Total Annual Revenues	Total Annual Revenues	Estimated Change	Percentage	Estimated Number of Customers' Bills		
Conventional Rates		@January 2022 Rates[a]	@January 2023 Rates[a]	@January 2023 Rates[d]	Change	Increased	Decreased	Unchanged[e]
1 - Rate I [b]	Residential & Religious	$3,852,100,470	$4,320,317,680	$468,217,210	12.15%	35,812,027	-	32
2	General - Small	698,754,644	798,245,364	99,490,720	14.24%	4,937,300	-	-
5 - Rate I	Electric Traction Systems	163,464	184,604	21,140	12.93%	110	-	-
6	Public & Private Street Lighting	3,392,221	4,179,717	787,496	23.21%	40,858	-	-
8 - Rate I	Multiple Dwellings - Redistribution	295,954,879	328,189,607	32,234,728	10.89%	20,747	-	-
9 - Rate I	General - Large	3,295,873,998	3,666,478,927	370,604,929	11.24%	1,544,897	59	2
12 - Rate I	Multiple Dwelling - Space Heating	27,172,096	30,293,017	3,120,921	11.49%	5,292	-	-
Sub-Total	Con Edison's Conventional Rates	$8,173,411,772	$9,147,888,916	$974,477,144	11.92%	42,361,231	59	34
Con Edison Service Classification -								
Time-of-Day Rates								
1 - Rate II	Residential & Religious	$14,155,707	$16,808,606	$2,652,899	18.74%	17,793	-	-
1 - Rate III	Residential & Religious - Voluntary	793,379	907,233	113,854	14.35%	4,056	-	16
2 - Rate II	General - Small	26,707,040	31,684,558	4,977,518	18.64%	36,456	-	-
5 - Rate II	Electric Traction Systems	14,470,284	15,395,279	924,995	6.39%	60	-	-
8 - Rate II	Multiple Dwellings - Redistribution	23,021,044	25,337,168	2,316,124	10.06%	227	-	-
8 - Rate III	Multiple Dwellings - Redistribution - Voluntary	20,611,990	22,729,488	2,117,498	10.27%	924	-	-
9 - Rate II	General - Large	1,418,125,622	1,535,573,118	117,447,496	8.28%	9,533	-	-
9 - Rate III	General - Large - Voluntary	344,194,570	372,010,865	27,816,295	8.08%	59,284	-	-
12 - Rate II	Multiple Dwelling - Space Heating	31,579,053	35,425,676	3,846,623	12.18%	321	-	-
12 - Rate III	Multiple Dwelling - Space Heating - Voluntary	-	-	-		-	-	-
13 - Rate I	Bulk Power - High Tension - Housing Developments	3,867,999	4,386,723	518,724	13.41%	12	-	-
Sub-Total	Con Edison's Time-of-Day Rates	$1,897,526,688	$2,060,258,714	$162,732,026	8.58%	128,666	-	16
Con Edison Total	Con Edison's Total Excluding Special Contract	$10,070,938,460	$11,208,147,630	$1,137,209,170 [c]	11.29% [c]	42,489,897	59	50

[a] Total Annual Revenues for all customers include: T&D delivery charge and estimated market supply charge, monthly adjustment clause, system benefits charge, dynamic load management, EV Make-Ready Surcharge, and the associated gross receipts taxes. The market supply charge revenues for retail access customers are equivalent to what these customers would have paid as full service customers.

[b] Total Annual Revenues in Service Classification No. 1 include customers currently served under Rider D.

[c] The change in Con Edison P.S.C. No. 10 revenues for the rate year, i.e., the twelve months ending December 31, 2023, equates to $1,057.6 million, or an overall increase of 11.3%.

[d] Reflects the overall impacts by class, including the net effect of the increase in low income funding and low income discounts.

[e] Number of customer bills unchanged have bill impacts ranging from -0.01% to 0.01%.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Estimated Effect on NYPA Delivery Service Conventional and TOD Revenue Resulting from the Application of
Proposed Conventional and TOD Rates and Charges Based on Sales and Revenues For the 12 Months Ended December 31, 2019

NYPA Delivery Service	Total Annual Revenues @January 2022 Rates[a]	Total Annual Revenues @January 2023 Rates[a]	Estimated Change @January 2023 Rates	Percentage Change
NYPA Total	$1,464,818,149	$1,612,085,837	$147,267,688 [b]	10.05% [b]

[a] Total Annual Revenues include delivery service revenues, DLM, EV Make-Ready Surcharge, and estimated supply revenues associated with customers billed under the PASNY No. 12 tariff.

[b] Based on sales and revenues for the rate year, i.e., the twelve months ending December 31, 2023 such increase in NYPA Delivery Service revenue equates to $141.2 million or an overall increase of 10.1%.

Appendix G

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
Estimated Effect on Gas Customers' Bills and Company Revenues Resulting from Proposed Gas Rates
Based on Forecasted Sales and Revenues for the Twelve Months Ending December 31, 2023 for Service Classification Nos. 1, 2, 3, 13 and 14
and the Corresponding SC 9 Firm Transportation Sub-classes

Firm Service Classification (Sales and Transportation)	Annual Therms	Total Annual Revenues at Current 01/01/22 Rates (b)	Total Annual Revenues at Proposed 01/01/23 Rates (b)	Estimated Total Annual Revenues Increase/(Decrease)	Percent Change	Number of Customers' Bills Increased	Number of Customers' Bills Decreased	Number of Customers' Bills Not Changed (c)
1 - Residential & Religious	38,160,000	$ 286,004,700	$ 349,123,925	$ 63,119,225	22.1%	6,333,450	0	0
2 - General - Rate I (a)	254,300,000	$ 307,888,432	$ 350,792,968	$ 42,904,536	13.9%	801,562	0	0
2 - Rider H - Distribution Generation	75,430,000	$ 61,162,935	$ 65,966,276	$ 4,803,341	7.9%	2,469	0	0
2 - General - Rate II - (a)	341,670,000	$ 469,866,983	$ 552,417,340	$ 82,550,356	17.6%	734,048	0	0
2 - Total Commercial	671,400,000	$ 838,918,350	$ 969,176,584	$ 130,258,234	15.5%	1,538,079	0	0
3 - Residential & Religious - Heating (a)	1,004,980,000	$ 1,638,980,433	$ 1,948,105,441	$ 309,125,008	18.9%	3,565,477	0	0
3 - Rider J - Distribution Generation	20,000	$ 26,031	$ 30,412	$ 4,382	16.8%	84	0	0
13 - Seasonal Off Peak Firm Service	540,000	$ 805,870	$ 948,972	$ 143,102	17.8%	3,519	0	0
14 - Natural Gas Vehicles	120,000	$ 284,264	$ 284,264					
Total Firm Sales & Firm Transportation	1,715,220,000	2,765,019,648	3,267,669,598	502,649,950	18.2%	11,440,610	0	0

(a) Gas air-conditioning is included in SC 2 and SC 3.

(b) Annual Revenues:
include gas cost factor, monthly rate adjustment, merchant function charges and various other charges used in calculating Rate Year Revenues;
include gas supply costs for transportation customers equivalent to what these customers would have paid as full service customers; and

(c) Number of customers' bills not changed have bill impacts ranging from -0.01% to 0.01%.

APPENDIX H

Consolidated Edison Company of New York, Inc.

Typical Residential Customer Bill Impacts

	Bills at			Percent Change	
	Current Rates	Proposed Rates	Change	Delivery	Total Bill
Electric					
SC 1 New York City					
280 kWh	$82.90	$94.11	$11.21	18.4%	13.5%
SC 1 Westchester					
425 kWh	$116.90	$132.50	$15.60	18.6%	13.3%
SC 1 600 kWh	$157.97	$178.87	$20.90	18.8%	13.2%
Gas					
SC 3 Heating Customer					
100 Therms	$198.54	$236.42	$37.88	26.8%	19.1%

P.S.C. No. 10 – Electricity

TARIFF LEAVES

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General Rules – Continued

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General Rules – Continued

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General Rules – Continued

GENERAL RULES

2. Definitions and Abbreviations of Terms Used in this Rate Schedule - Continued

- **"Public right-of-way"** means the territorial limits of any street, avenue, road or way (other than a limited access thoroughfare) that is for any highway purpose under the jurisdiction of the State of New York or the legislative body of any county, city, town or village and is open to public use.

- **"Public Service Commission"** or the **"Commission"** or the abbreviation **"PSC"** refers to the Public Service Commission of the State of New York.

- **"Pure Base Revenue"** means revenue attributable to Demand Delivery Charges, Energy Delivery Charges, the Reactive Power Demand Charge, and the Customer Charge, if applicable under the Customer's Service Classification, or comparable charges under the applicable Riders to the Customer's Service Classification, after application of any applicable rate reductions under Rider J or SC 9 Special Provision H and before application of the Increase in Rates and Charges; provided, however, that if the Minimum Monthly Charge (as described in General Rule 10.10) would apply, then "Pure Base Revenue," as stated in General Rule 5.3 and 5.4 and under the Rider J and Rider Y facilities' cost tests, means revenue attributable to the Minimum Monthly Charge after application of any applicable rate reductions under Rider J or SC 9 Special Provision H, plus the Reactive Power Demand Charge, and before application of the Increase in Rates and Charges.

GENERAL RULES

5. Installation and Maintenance of Overhead and Underground Facilities

5.1 Definitions: The terms defined below apply to this General Rule only.

- **"Applicant"** means a developer, builder, person, partnership, association, corporation or governmental agency requesting the provision of electric service either:
  - at a premises to be used as the applicant's residence (residing applicant);
  - in a residence to be used by others (non-residing applicant), provided, however, that a governmental agency applying for service on behalf of a client, who would otherwise be a residing applicant, shall be treated as a residing applicant;
  - at a non-residential premises; or,
  - at a location in the Public right-of-way.

- **"Appurtenant facilities"** means the necessary and ancillary accessories to an electric line that enable the transportation and distribution of electric energy.

- **"Distribution line"** means an electric line used to distribute electric energy, which will or may reasonably be expected to provide service to more than one Customer.

- **"Multiple occupancy building"** means a structure (including row houses) enclosed within exterior walls or fire walls, which is built, erected, and framed of component structural parts and is designed to contain four or more individual dwelling units for permanent residential occupancy.

- **"New construction"** means the installation of new electric distribution lines, service lines, and appurtenant facilities on any R/W where no such electric distribution line exists, and may also include (in connection with such installation) the addition of appurtenant facilities (other than replacement facilities) to existing distribution lines. The installation of a new facility parallel to and on the same R/W as an existing underground facility also constitutes the new construction of such facility.

- **"Premises"** means a parcel of land; or more than one building and/or parcel of land proximate to each other if there is common use, whether or not such buildings or parcels are individually owned or leased or separated by public or private roads.

- **"Public right-of-way"** means the area within the territorial limits of any street, avenue, road or way that is for any highway purpose under the jurisdiction of the State of New York or of the legislative body of any county, city, town or village that is open to public use and that may be used for the placement of Company facilities.

GENERAL RULES

5. Installation and Maintenance of Overhead and Underground Facilities - Continued

5.2. Common Provisions Applicable to the Installation and Maintenance of Overhead and Underground Facilities – Continued

5.2.4 Excess Distribution Facilities - Continued

5.2.4.4 Distributed Energy Resources Make Ready Program for Disadvantaged Communities and Low-Income Customers

From January 1, 2023 through December 31, 2025, the Company will offset the costs of necessary new interconnections and EDF costs for qualified participants seeking to interconnect clean distributed energy resources in disadvantaged communities or that serve low-income customers. Eligibility for these offsets, including the amount of the offset given, will be determined according to the program's rules as published on the Con Edison website.

5.2.5 Permits

The Company will make, or cause to be made, application for any necessary street permits for installing its service facilities and shall not be required to furnish electric service until a reasonable time after such permits are granted. The Customer shall obtain, or cause to be obtained by its contractor or representative, and present to the Company for registration, all permits (excepting street permits), consents, and certificates necessary to give the Company or its representatives access to the installation and equipment and to enable its service lateral to be connected therewith, or for other purposes in connection with the supply of electric service. No application will be deemed to be complete until all permits (excepting street permits), consents, and certificates have been obtained by the Customer and presented to the Company for registration.

GENERAL RULES

5. Installation and Maintenance of Overhead and Underground Facilities - Continued

5.2 Common Provisions Applicable to the Installation and Maintenance of Overhead and Underground Facilities – Continued

5.2.6 Easements or Rights-of-Way When Required for Line Extensions

When required by the Company, the Customer (or Customers) shall execute and deliver to the Company, free from cost, permanent easements or rights-of-way for the placing and maintaining of an extended line in so far as the line extension or subsequent additions thereto affect the property owned by the Customer (or Customers).

The Company shall not be obliged to commence construction of an extension of its electric system until the Customer (or Customers) to be served by such extension have obtained and delivered to the Company satisfactory permanent easements or rights-of-way agreements or have agreed to pay a lump sum or a surcharge in accordance with General Rule 5 for such costs as may be incurred by the Company if at the Customer's request it obtains such easements or rights-of-way.

A successor to a Customer who has agreed to pay such a surcharge shall, as a condition of receiving service, agree to assume the surcharge obligations of the predecessor.

These provisions are applicable irrespective of the length of the extension.

5.2.7 Temporary Service

Where the use of service will be temporary, the Customer will be required to pay in advance to the Company the estimated cost of the Company's service installation and removal (including any street reinforcement and extension required), as determined by the Company and endorsed on the agreement for service. The Customer shall not be relieved of the obligation to fulfill the term and minimum charge provisions of the agreement for service. Where the applicable Service Classification has a term of 1 year or more the Customer may contract for temporary service for a lesser period but not less than 30 days.

Temporary service for the purposes hereof shall include, but shall not be limited to, use of service for construction sites, fairs, celebrations, and other temporary activities or structures; or under circumstances where the Company has reason to believe that the facilities installed by the Company to provide service may not be used for permanent supply.

The Customer's payment hereunder shall be refundable if circumstances change after the Customer commences to take service, and the Company has reasonable assurance that the use of the service will not be temporary and that the Company's facilities will be used for permanent supply.

In instances where service will be used for less than 60 days for any purpose or the service installation presents difficulties as to metering, the Company may estimate the amount of the charges for such service according to the Service Classification applied for and specify, by endorsement upon the agreement for service, such amount as the charges for the service.

GENERAL RULES

5. Installation and Maintenance of Overhead and Underground Facilities - Continued

5.2 Common Provisions Applicable to the Installation and Maintenance of Overhead and Underground Facilities – Continued

5.2.8 Street or Sidewalk Service

Where the use of service is for Customer equipment that is located in the Public right-of-way, the Customer will be required to pay in advance to the Company the estimated cost of the Company's service installation (including any street reinforcement and extension required), as determined by the Company and agreed to by the Customer. The Company will charge for removal costs as applicable when the equipment is removed.

Street or Sidewalk Service is for equipment not associated with a premise or eligible for temporary service under General Rule 5.2.7.

Street or Sidewalk Service for the purposes hereof shall include, but shall not be limited to, use of service to structures and equipment in the Public right-of-way such as newsstands, bus shelters, kiosks, cameras or video recorders, communication equipment, computers, advertising and other display panels, or other electric equipment installed in the Public right-of-way; or under circumstances where the Company has reason to believe that the equipment installed by the Customer is subject to removal or relocation by the authorities having jurisdiction over the Public right-of-way; or under circumstances where the Company has reason to believe that the equipment installed by the Customer is subject to removal or relocation by the authorities having jurisdiction over the Public right-of-way.

GENERAL RULES

5. Installation and Maintenance of Overhead and Underground Facilities - Continued

5.5 Underground Facilities

5.5.1 Facilities to be Installed Underground

The Company shall install underground any distribution line, service line, and appurtenant facilities which are necessary to furnish permanent electric service as follows:

a. To a residential subdivision in which it is planned to build five or more new residential buildings, if the residential subdivision will require no more than 200 trench feet of facilities per dwelling unit planned within the residential subdivision, subject to the exceptions listed in General Rule 5.5.4.6;
b. To one or more multiple occupancy buildings if the project will require no more than 200 trench feet of facilities per dwelling unit planned within the project, subject to the exceptions listed in General Rule 5.5.4.6;
c. To any building or residential subdivision which a local governmental authority having jurisdiction to do so requires the underground installation of facilities provided that the Company shall not install service lines beyond the property line for non-residential buildings in such instances;
d. When the Company elects to provide underground facilities; and
e. In response to a request for underground facilities by an applicant for service.

In all other circumstances not including the foregoing, the Company will install its facilities overhead.

For the purposes of subdivisions and multiple occupancy buildings under “a” and “b” above, the number of dwelling units is the criterion to be used to determine whether installation is required to be underground. Each lot shown on the approved subdivision map shall, in the case of a single family dwelling, be considered to contain one dwelling unit unless there is sufficient contrary evidence to render it unlikely that each lot will contain a separate dwelling unit (e.g., a foundation is constructed occupying two lots). The measurement of trench footage shall be the shortest distance required to serve the homes within the residential subdivision, consistent with the Company's obligation to provide safe and adequate service.

GENERAL RULES

5. Installation and Maintenance of Overhead and Underground Facilities – Continued

5.6 Transformers and Associated Equipment

5.6.1 Space for Transforming Apparatus

Where the Company considers transformers and associated equipment reasonably necessary for the adequate supply of service to a Customer or a Customer's premises, the Customer shall provide suitable space and reasonable access thereto, without rental charge. To facilitate access and ventilation, such suitable space shall be immediately adjacent to the property line and outside the building and, for underground service, immediately below street grade. Space for non-submersible transformers and associated equipment must be protected from flooding in accordance with the Company's specifications.

Where such suitable space for transformers and associated equipment is provided, the Company, at its expense, will construct the transformer enclosures abutting the property line and will assume any compensation payable by the Company to the municipal authorities for any necessary sub-sidewalk transformer vaults and structures, and the Company will furnish, install and maintain the transformers and associated equipment therein. Where the Customer does not provide such suitable space, the transformers and associated equipment will be furnished by the Company and installed and maintained by the Customer in accordance with the Company's specifications.

5.6.2 Interior Distribution Installation

At the request of the Customer, the Company's transformers and associated equipment may be installed by the Customer at one or more points in the building or premises on the same or different levels, provided that the entire service installation within the premises, including the installation of, and connections to the Company's transformers and associated equipment, or replacements thereof, is made at the Customer's expense in accordance with the Company's specifications.

GENERAL RULES

6. Meters – Continued

6.5 Meters with Communications Capabilities

(1) The Company will provide and maintain the communications service for the following: (a) Full Service Customers who are served under Rider M on a mandatory basis, and Customers taking a non-Company Supply service who would be served under Rider M on a mandatory basis if they purchased supply from the Company; (b) Customers served under Rate II or Rate IV of SC 5, Rate II or Rate V of SC 8, 9, or 12, or Rate I or Rate II of SC 13; (c) Customers subject to Reactive Power Demand Charges, pursuant to General Rule 10.11; (d) Standby Service Customers who were billed for Full Service or Retail Access Service under Rate I or Rate II of SC 3 or SC 10 on and before February 1, 2004; and (e) Customers equipped with Interval Meters installed under the Company's AMI program.

(2) The Customer, at its expense, will provide and maintain the communications service unless the Company is required to do so as specified in paragraph (1) above. If communications is by telephone line, the Customer shall provide a dedicated telephone line. If a Customer's telephone line is not operational for any reason when the Company attempts to read the meter, the Customer will be assessed the charge specified in General Rule 16.4.

GENERAL RULES

6. Meters - Continued

6.10 AMR/AMI Meter Opt-out

Except for Residential Customers who are required to have an Interval Meter, Residential Customers who have, or are scheduled to have, automated meters installed by the Company on their premises may elect to opt out of an Automated Meter Reading equipped meter ("AMR meter") or an Advanced Metering Infrastructure equipped meter ("AMI meter") and, thereby, have their meters read manually, by completing an automated-meter opt-out form. Information about how to opt out of AMR/AMI metering, including forms, can be found on the Company's website at https://www.coned.com/en/our-energy-future/technology-innovation/smart-meters. Customers who opt out of AMR or AMI metering will be subject to the following provisions:

a. Notice

The Company has a plan to replace non-AMI meters, including AMR meters, with AMI meters throughout its service area. At least 30 days in advance of the planned AMI meter installation at the Customer's premises, the Company will notify the Customer in writing of the forthcoming meter installation and ability to opt out. Customers who opt out of AMI metering prior to the planned installation will not be subject to a meter change-out fee.

In the event the Company replaces a non-AMI meter with an AMI meter and does not provide at least 30 days' advance notice (e.g., replacement of a broken meter), the Company will notify the Customer in writing of the AMI meter installation and ability to opt out. Customers who opt out of AMI metering within 30 days of such notice will not be subject to a meter change-out fee.

b. Fees

Manual Meter Reading Fee: If the Customer opts out of AMR or AMI metering or refuses to permit the Company to install such metering, the Company will attempt to read the meter manually bi-monthly and render bills monthly, as described in General Rule 10.3. The monthly bills will contain an incremental charge, per electric account or combined electric and gas account, at half the charge specified in General Rule 17.1.f.

Meter Change-out Fee: If an AMR or AMI meter was previously installed and the Customer opts out of such metering, the Customer must pay $104.74 for the meter change-out (i.e., removal of the AMR or AMI meter, as applicable, and installation of a solid-state non-communicating meter), except as described in "Notice" above.

GENERAL RULES

7. Customer's Installation and Equipment

7.1 Customer Wiring and Equipment

Wherever it is provided that the Customer shall perform any work or furnish or maintain any equipment or facilities, the Customer shall do the same or cause the same to be done at the Customer's expense.

The Company will determine the location, and specify the type and manner of installation and connection, of the service terminating equipment, metering equipment, and communications equipment, and will furnish this information to the Customer upon request. The Customer shall obtain this information as one of the first steps in planning the electrical installation.

All construction by the Customer from the point of service termination to and inclusive of the meter equipment shall be subject to approval by the Company.

The Customer shall furnish, install, and maintain all electric and communications wiring and equipment, including standpipes, conduits, fittings, wires, cables, fuses, boxes, service switch, meter equipment (except meters, metering transformers, socket access points, and antennas), and meter wiring, beginning with the point of service termination. The Customer shall furnish, install and maintain the facilities necessary to accept outdoor meter(s) wherever feasible when service is provided to a new one-, two-, or three-family home or when the service conduit to an existing one-, two- or three-family home must be replaced in response to a Customer's request for an upgraded service.

The Customer shall install and connect metering transformers on initial installation and upon subsequent alteration to the main cable or bus circuit. The Customer shall furnish and install meter wiring between metering transformers or meter equipment and the meters, but the Company will make the final connection of such wiring to the meters. Where demand metering devices are required in addition to watthour meters, the Customer shall furnish, install, maintain, and remove, as necessary, meter equipment for such devices.

The Customer shall provide, or arrange to be provided with, properly identified, suitable wiring and equipment to assure that all service supplied to the Customer, and only service supplied to the Customer, shall register on the meter(s) or other measuring device(s) used for the measurement and billing of the Customer's service. Where the Customer's service equals or exceeds 1000 amperes, and the service is measured by one or more current transformer meters installed and maintained by the Company, the Company shall not be liable to refund payments for service rendered more than 24 months before the Company became aware that such payments were based on incorrect billing resulting from the Customer's failure to provide, or arrange to be provided with, properly identified, suitable wiring and equipment, provided, however, that the Company shall be responsible for proving the connection between the current transformer and the meter pan(s) identified to the Customer's service.

For Customers served under the Company's Selective Undergrounding Program, the Company will furnish and install the above wiring and equipment, as necessary; provided that the Customer will maintain the wiring and equipment thereafter.

The Customer shall comply with these requirements in accordance with Company specifications.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation

The following interconnection and operation requirements are applicable to Standby Service Customers served under General Rule 20 and Buy-back service Customers served under SC 11.

8.4.1 The following provisions are applicable to interconnection and operation of private generating facilities (or wholesale generating facilities for Standby Service) on the premises not connected directly to transmission facilities (that is, delivery facilities other than distribution facilities) that: (i) commenced operation prior to February 1, 2000; or (ii) commenced operation between February 1, 2000 and December 30, 2004, and either have a total nameplate rating between 301 kVA and 2 MW or are connected in parallel with the network system; or (iii) commenced operation between December 31, 2004 and April 28, 2016, have a total nameplate rating greater than 2 MW, and are connected in parallel with the distribution system; or (iv) commenced operation after April 28, 2016, have a total nameplate rating greater than 5 MW, and are connected in parallel with the distribution system. The Company's distributed generation guides (the "guides") on the Company's website address installation and upgrades of electric generation facilities. When the guides are revised, they will be posted to the Company's website.

(A) Interconnection Charges

The Customer will be required to pay:

(1) A charge for the reasonable costs of connection, including the costs of initial engineering evaluations, switching, metering, transmission, distribution, safety provisions, engineering, administrative costs, and any associated tax expenses incurred by the Company directly related to the installation of the facilities deemed necessary by the Company to permit interconnected operations with a Customer, to the extent such costs are in excess of the corresponding costs which the Company would have incurred had the Customer not taken Standby Service or Buy-back service. All such facilities will remain the property of the Company. The Customer may pay for the foregoing interconnection costs either:

(a) by paying in full prior to the commencement of Standby Service or Buy-back service; or

(b) by paying at least twenty-five percent of the interconnection costs prior to the commencement of Standby Service or Buy-back service and arranging with the Company to pay over not more than a five-year period the balance of such interconnection costs plus interest at the other Customer provided capital rate in effect at the time a payment plan is agreed upon with the Company. The Company may require a Customer to provide adequate security for the payment of the balance of the interconnection costs due the Company under the payment agreement.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation - Continued

8.4.1 – Continued

(A) – Continued

(1) - Continued

The costs of delivery system reinforcements required for parallel operations and incurred subsequent to interconnection are an element of the interconnection costs and will be charged to the Customer, provided that such costs are initially foreseen, but not necessarily incurred at the time of interconnection. The Customer may pay for this element of interconnection cost at the time it is incurred, or pursuant to a payment agreement similar to the one described above.

(2) An annual charge of 12.1 percent of the capital costs of interconnection, including the costs of delivery system reinforcements, to cover property taxes and operation and maintenance expenses. The annual charge shall be determined by multiplying the rate of 12.1 percent by the total capital costs of interconnection. The annual charge is payable by the Customer in monthly installments equal to one-twelfth of the annual charge.

At the Customer's option, the Customer may pay a non-refundable lump sum charge instead of annual surcharges. The lump sum charge will be equal to the net present value of the annual payments using the following formula:

Lump Sum Value = Cfn / (R – g)

Where:
Cfn = Annual payment stream;
R = Pre-tax cost of capital authorized by the PSC in the Company’s most recent rate case; and
g = Long term growth rate, set at 0 percent.

(B) Other Requirements

(1) Metering equipment (except meters and metering transformers) and interrupting equipment, as specified by the Company, will be installed and maintained by the Customer in accordance with Company specifications. Where such facilities are located on the Company’s property, they will be installed and maintained by the Company at the Customer’s expense.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation - Continued

8.4.1 – Continued

(B) – Continued

(2) All requests for parallel operation will be reviewed on a case-by-case basis. Parallel operation will be permitted only if, and to the extent, such operation does not jeopardize the adequacy or reliability of service to the Company's other Customers. Failure of the Customer at any time to comply with the terms and conditions specified by the Company in order to permit parallel operation will result in the Customer forfeiting its right to operate in parallel with the Company's system. In the event a Customer forfeits its right to operate in parallel with the Company's system, the Customer will be required to bear the reasonable expense associated with disconnecting the Customer's private plant from the Company's system. Where there is a dispute between the Customer and the Company with respect to the standards and charges for interconnection, the Customer may apply to the Public Service Commission for a ruling in the matter.

(3) The Customer's generating plant and the Company's system may be operated in parallel as required subject to the Customer's compliance with the Company's design requirements and operating rules and procedures. To accomplish such parallel operation in a safe, economical, and efficient manner, operating instructions shall be prepared by the Company, and adhered to by the authorized operating representatives of the Customer. Such operating instructions shall include, among other things, procedures for:

(a) Maintaining proper voltage and frequency and for putting into effect voltage changes as required from time to time;
(b) Phasing and synchronizing the Customer's generating plant and the Company's system;
(c) Taking feeders out of service for maintenance or during emergency conditions and restoring them to service thereafter; and
(d) Controlling the flow of real power and reactive power between the Customer's generating plant and the Company's system.

Where there is to be parallel operation, the Customer's authorized operating representatives shall receive the necessary training from the Company's authorized operating representatives in the Company's operating procedures before parallel operation is begun.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation - Continued

8.4.1 – Continued

(B) – Continued

(4) Where the Customer operates in parallel, the Customer shall provide and maintain on its premises all necessary facilities, as specified by the Company, for connecting the Company's feeder cables to the Customer's generating station, including transformers, circuit breakers, and all equipment and facilities necessary and required for synchronizing the Customer's generating plant with the Company's system and for controlling the flow of energy and wattless current and for protection of the interconnected systems. Such required facilities may include a communication system between the Customer's generating plant and the Company's system or district operator consisting of transmitting equipment and a communications path such as a leased telephone line or lines connecting these points to provide transfer trip of the Customer tie. Voice communication and telemetering of loads shall be provided at the Customer's expense.

(5) The Customer is solely responsible for providing adequate protection for Customer's facilities operating in parallel with the Company's system. Except where caused by the Company's negligence, the Company will not be liable for, and the Customer shall indemnify and hold the Company harmless for, damages to the property of the Company or others or injuries to persons arising out of any occurrence related to the Customer's ownership, use or operation of the Customer's facilities.

(6) For Standby Service: When a Customer who is a wholesale generator takes service through the same bus bar that it uses to export power to the wholesale grid, the station power when the generator is operating will be treated as if the generator were self-supplying from the load side of the meter.

For Buy-back service: The Customer shall provide suitable equipment, including indicating and recording instruments and telemetering, required by the Company for the proper operation and monitoring of the interconnection. The Customer's authorized representative in charge of the operation of the Customer's generating plant shall cause readings of the aforesaid meters to be taken at such intervals as may be required by the Company. The Customer will maintain a log record of such readings as part of the log records of the Customer's generating plant. Such logs will be made available for Company inspection and review at the Company's request.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation - Continued

8.4.2 The following provisions are applicable to interconnection and operation of private generating facilities (or wholesale generating facilities for Standby Service) on the premises that: (i) commenced operation between February 1, 2000 and December 30, 2004, have a total nameplate rating of 300 kVA or less, and are connected in parallel with the radial system; or (ii) commenced operation between December 31, 2004 and April 28, 2016, have a total nameplate rating of 2 MW or less, and are connected in parallel with the distribution system; or (iii) commenced operation after April 28, 2016, have a total nameplate rating of 5 MW or less, and are connected in parallel with the distribution system.

(A) Interconnection Charges

The Customer will be required to pay:

(1) Advance payment for the estimated costs of any equipment and facilities installed on the Company's system, including metering, necessary to permit operation of the Customer's generation facilities in parallel with the Company's system. The amounts and timing of Customers' payments shall be determined in accordance with the Standardized Interconnection Requirements set forth in Addendum - SIR.

(2) A cost-based advance payment for the Company's review of the Customer's proposed interconnection design package and for any studies, including but not limited to the Coordinated Electric System Interconnection Review, performed by the Company with respect to the interconnection of the Customer's generation facilities.

The Company will reconcile its actual costs with the total of the Customer's advance payment for estimated costs of equipment and facilities and advance payment for reviews and studies. The Customer will pay or the Company will refund, without interest, the difference.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation – Continued

8.4.2 – Continued

(B) Other Requirements

(1) Customers' applications to attach parallel generation equipment to the Company's distribution system will be made using the applications set forth in Addendum – SIR. An application fee may be required as specified in Addendum – SIR.

(2) Assuming the conditions of the Standardized Interconnection Requirements are met, the Company and the Customer will execute the New York State Standardized Contract set forth in Addendum - SIR.

(3) The installation and parallel operation of generation facilities will be in accordance with the Standardized Interconnection Requirements.

(4) Parallel operation of synchronous generators with the secondary network system will be permitted only if, and to the extent, such operation does not jeopardize the adequacy or reliability of service to the Company's other Customers.

GENERAL RULES

8. Customer Use of Generating Equipment – Continued

8.4 Interconnection and Operation – Continued

8.4.3 – Common Provisions

(A) A Customer taking Standby Service through direct interconnection to a transmission facility shall be subject to interconnection charges imposed under a tariff of the New York State Independent System Operator in addition to any non-duplicative charges hereunder.

(B) Failure of the Customer to pay any of the interconnection charges or annual charges, when due, shall be cause for termination of service in accordance with the procedures specified in this Rate Schedule.

(C) The meter required for Standby Service may include equipment either to prevent reverse meter registration or to separately measure Customer-generated electricity and electricity delivered by the Company.

(D) Export of power into the Company's system will not be permitted under Standby Service, except as provided under General Rules 20.4.5, 20.4.6, and 20.4.7.

(E) A Customer may segregate any portion of its total requirements at the premises so that such portion shall be served exclusively with the Company's service under another and appropriate Service Classification consistent with General Rule 8.1.

GENERAL RULES

10. Meter Reading and Billing - Continued

10.11 Reactive Power Demand Charge - Continued

(2) Charge per kVar

$2.38 per kVar	applicable to Customers specified in paragraph (1)(a), (b), (c), or (d) above for billable reactive power demand. Billable reactive power demand, in kVar, shall be equal to the kVar at the time of the kW maximum demand (as defined in General Rule 10.4) during the billing period (all hours, all days) less one-third of such kW maximum demand; provided, however, that, if this difference is less than zero, the billable reactive power demand shall be zero. If the same kW maximum demand occurs two or more times during the billing period, the reactive power demand will be determined at the time of the last kW maximum demand occurrence. If the Company restricts an existing Customer with synchronous generation from utilizing Customer load power factor correction through the Generator's controls, the Customer will not be subject to the above charge until such time that the Company removes this restriction.
$2.38 per kVar	applicable to Customers specified in paragraph (1)(e) above for the kVar requirements of the induction-generation equipment

(3) A Customer subject to the Reactive Power Demand Charge pursuant to paragraph (1)(a), (b), or (c) above will no longer be subject to the Reactive Power Demand Charge commencing in the month following 12 consecutive months in which the maximum demand does not exceed 300 kW.

(4) After the installation of communications service, the Company will make available to a Customer its kVar and kW interval data via the Internet. Existing Customers subject to the Reactive Power Demand Charge pursuant to paragraphs (1)(a) above will generally be provided access to daily kVar and kW interval data during each of the six months in advance of being subject to the Reactive Power Demand Charge. Customer access to daily kW and kVar interval data via the Internet will generally be provided on a one-day lag, subject to the Company resolving communications issues that may arise from time to time.

GENERAL RULES

11. Billing Applicable to Service Under Certain Economic Development Programs – Continued

b. Allocating Demand to the Various Programs

The demand served under RNY, as applicable, will be the lower of (i) the demand allocation under that program or (ii) the registered monthly maximum demand. If Delivery Service for the RNY load is furnished under Special Provision H of SC 9, the demand served under RNY for Delivery Service will be the lower of (i) the RNY demand allocation or (ii) the registered maximum monthly maximum demand less the demand served under Special Provision H of SC 9. A Customer who has demand served under WTC is not eligible to have Delivery Service for RNY load served under Special Provision H of SC 9.

The demand served under WTC, as applicable, will be the lower of (i) the demand allocation under that program or (ii) the registered monthly maximum demand less any demand served under RNY. If billing is issued under WTC Standby Service rates, the As-used Daily Delivery Service Demand Charge for each time period will be equal to the Daily Peak Demand during the applicable time period multiplied by the Allocation Ratio.

For purposes of General Rule 11, "registered monthly maximum demand" means the maximum demand as defined in General Rule 10.4, except as follows:

For Rider M Customers, commencing with bills having a "from" date on or after June 1, 2016, capacity served under RNY or WTC, as applicable, will be the Customer's ICAP Tag for the billing month (as described in General Rule 25.1) multiplied by the Allocation Ratio for that program.

c. Allocation Ratio

The "Allocation Ratio" under each program equals the demand served under that program, as determined in subparagraph "b" above, divided by the registered monthly maximum demand.

GENERAL RULES

15. Collection, Reconnection and Meter Recovery Charges

The Customer shall pay the following charges as a condition of the continuation or re-establishment of service in the following circumstances:

15.1 Collection Charge

A $29.00 collection charge, if, after a lawful notice of discontinuance of service for non-payment, the Customer has failed to pay all of the amount due within the time specified in the notice and the Company thereafter sends an employee to the Customer's premises to collect payment; however, if more than one visit is made to the Customer to collect or to disconnect service, this charge shall be collected no more than twice in the same transaction regardless of the number of visits made to the Customer to collect or to disconnect service. The collection charge is not applicable to a Customer taking service under SC 1 or to any other Customer who uses such service primarily for his or her residential purposes and has so notified the Company.

15.2 Reconnection Charge

A reconnection charge for the re-establishment of service, if service to the same Customer at the same meter location has been discontinued for non-payment of a deposit or of any rates and charges billed pursuant to this Rate Schedule, including service disconnected due to evidence of tampering with Company apparatus, within twelve months of the Customer's request to re-establish service. The charge for re-establishment of service, except as modified in General Rule 15.4, during the hours of 8 A.M. to 4 P.M. Monday through Friday, excluding holidays, shall be $26.00, and $28.00 at all other times, except that, if service was disconnected in the street, the reconnection charge shall be $271.00. The reconnection charge when service was disconnected due to evidence of tampering or when service was disconnected in the street is not applicable to a Customer taking service under SC 1 or to any other Customer who uses such service primarily for his or her residential purposes and has so notified the Company.

There will be no reconnection charge for Customers with a remote connect/disconnect capable meter, whose service has been discontinued for non-payment of a deposit or of any rates and charges billed pursuant to this Rate Schedule, including service disconnected due to evidence of tampering with Company apparatus, within twelve months of the Customer’s request to re-establish service, if that Customer’s service is re-established remotely (i.e., without a Company representative present).

During each Rate Year that commences January 1, the reconnection charge will be waived for Customers enrolled in the Company’s Low Income Program under Rider S, subject to the following provisions:

(a) no waiver will be granted once the Company has waived $1,188,186 (the “target cost”) during that Rate Year; and
(b) the Company will notify parties in its most recent electric rate plan if it projects that the target cost will be reached during any Rate Year.

GENERAL RULES

16. Other Charges

16.1 Charge for Replacing a Damaged Meter

A charge for removing and replacing a Company owned meter that was damaged because the access controller to the meter did not exercise reasonable care or the meter was damaged due to tampering. The charge of $86.00 for a non-demand meter, $205.00 for a demand meter, and $265.00 for an AMI meter, shall be assessed on the account of the access controller even if the damaged meter was for the account of another customer, except that if the meter was damaged due to tampering, the charge shall be assessed on the account of the customer who benefited from such tampering.

16.2 Charge for Investigating Tampered Apparatus

A $413.00 charge for inspecting the apparatus, locking and sealing any tampered meter, billing, and associated administrative activities, where evidence of tampered Company apparatus is found.

16.3 Charge for Re-inspection

A $279.00 charge for each re-inspection required because the Customer's contractor submitted documentation that its work at the Customer's premises was completed according to Company specifications and is ready for final inspection by the Company, but the Company on its inspection found the work to be either incomplete or incorrectly performed.

16.4 Charge when a Customer's Telecommunications Equipment is Not Operational

If a Customer is required to provide and maintain the telecommunications equipment for the meter at its expense pursuant to General Rule 6.5, and the Customer's telephone line is not operational for any reason when the Company attempts to read the meter, the Customer will be assessed a charge of $50.00 on each monthly cycle date until the condition is corrected, and the Customer will be charged the fee specified in General Rule 17.1.f. for an on-site meter reading on each scheduled reading date.

GENERAL RULES

17. Special Services Performed by the Company at a Charge

17.1 Special Services at Stipulated Rates

Upon a Customer's request, the Company will perform the following special services for the Customer and will charge the Customer at the stipulated rates:

a. Make high potential proof tests on new high tension equipment of the Customer, or on existing high tension equipment of the Customer after completion of certain maintenance and alteration work. Where these tests are made at a Company Station and are not coincident to Company purpose tests, or are made on the Customer's premises, the following rates will apply:

High potential proof test, per visit to the premises:

Up to four hours $2,076.00

For each additional hour or portion thereof
if the cause is beyond the Company's control $519.00

If a high potential proof test fails and the Company is required to revisit the premises and retest, separate charges will apply to each visit.

b. Perform a 2500-volt direct-current Megger Test at the Customer’s premises $519.00

c. Take and test samples of dielectric fluid from Customer's high tension apparatus, where the apparatus is equipped with proper valves or fittings; or test samples of dielectric fluid supplied by the Customer in an approved container furnished by the Company at the following rates:

First sample taken by the Company $1,066.00
Each additional sample taken by the Company at the same time........ $670.00

Tests of samples supplied by the Customer in an approved container furnished by the Company and delivered to an authorized Company representative:

Each sample taken by the Customer $547.00

GENERAL RULES

17. Special Services Performed by the Company at a Charge - Continued

17.2 Special Services at Cost

Upon the request of a Customer or agent of the Customer, the Company will perform the following special services and charge the Customer or the Customer’s agent upon the basis of cost to the Company as defined in General Rule 17.3:

a. Install and remove temporary services as set forth in General Rule 5.2.7;

b. Change the point of service termination or location of the service lateral as set forth in General Rule 5.2.2;

c. Relocate a Company-owned or jointly-owned pole, provided that the City, Town or Village will issue an order at the Customer's request to relocate any existing street lighting equipment;

d. Make temporary changes to Company facilities to permit the moving of a building or equipment from one location to another;

e. Temporarily relocate underground service to City-owned or Company-owned lamppost, traffic standard, or similar facilities;

f. Relocate Company street facilities to accommodate Customers;

g. Remove and relocate Company facilities when a street is to become private property;

h. Install underground service from Company's overhead lines on the street;

i. Provide kilowatt demand pulses for single and/or coincident demand meters;

j. Inspect, maintain, repair, and replace transformers and related service facilities for Customers receiving high tension service which is metered on the low tension side of the transformer, as provided in General Rule 4.6;

GENERAL RULES

17. Special Services Performed by the Company at a Charge - Continued

17.2 Special Services at Cost - Continued

k. For a Customer served under Rider N, prepare an emergency supply plan and a storage facility; provide if requested, store, maintain, and test the mobile generating equipment associated with the Rider N service; transport the generating equipment to the Customer's service address; and supply personnel and fuel to operate the generating equipment;

l. Perform incidental environmental remediation work on Customer premises associated with the Company's performance of its transmission and distribution service obligations;

m. Interrupt or restore service to a Customer’s premises to accommodate internal maintenance and/or repair activities, provided that the charge is not applicable when such service interruption or restoration is performed between 7 A.M. and 3 P.M., Monday through Friday, excluding holidays;

n. Perform engineering work when the Company must design non-standard specifications for structures to house the Company’s transformers and associated equipment on the Customer’s premises to address site-specific conditions;

o. Expose the Customer's property line splice box to determine the fault location of cable, when the fault is not located within a Company facility; provided, however, that there will be no charge for exposing the property line splice box to a 1, 2 or 3 family house; and

p. Install and remove Street or Sidewalk Service as set forth in General Rule 5.2.8.

GENERAL RULES

17. Special Services Performed by the Company at a Charge - Continued

17.3 Definition of Cost

The cost to be charged for the furnishing of the special services listed in General Rule 17.2 and General Rule 17.7 consists of the following elements of cost where applicable. Where applicable, charges shall be increased to reflect the Percentage Increase in Rates and Charges, as explained in General Rule 30, and shown on the related Statement.

- Labor of the Company organization unit involved at average payroll rate plus related expenses and indirect costs. Overtime and Sunday rates will be charged where applicable;
- Material at the average actual storeroom price plus 13% for handling cost (sales taxes to be added where applicable);
- Use of transportation vehicles at rates covering operation, maintenance, carrying charges, and taxes;
- Contract work and sundry vendors' bills at invoice cost, including any taxes contained therein;
- Use of large tools and equipment at rates covering operation, maintenance, and carrying charges;
- Corporate overhead for the above five bulleted items at (a) 14% for engineering and drafting, unless the labor cost for those services is separately stated or was already charged on a prior invoice, (b) 17% for construction management, if applicable, and (c) 3% for administration.
- Salvage credit at storeroom price of materials reduced by salvaging cost, or at junk value;
- Governmental permits or licenses necessary to perform the service;
- Mobile generating equipment for service under Rider N at invoice cost, including any taxes contained therein, if purchased or at reproduction cost new less accrued depreciation if from on-hand equipment, plus costs incurred in purchasing, including acceptance inspection and testing (sales taxes to be added where applicable);
- Fuel for mobile generating equipment operation at invoice cost, including any taxes contained therein; and
- Use of real property at a rate covering operation, maintenance, carrying charges, and taxes.

GENERAL RULES

17. Special Services Performed by the Company at a Charge – Continued

17.6 Meter Upgrades and Purchases

Customers billed under all Service Classifications may request meter upgrades from the Company for a charge, upon the basis of cost to the Company as defined below. The cost to be charged for the meter upgrade consists of the following elements, where applicable:

a. Labor of the Company organization unit involved at average payroll rate plus related expenses and indirect costs. Overtime and Sunday rates will be charged where applicable;

b. Material (including but not limited to meter, input/output boards, demarcation box, adapters) at the average actual storeroom price plus handling costs at the Company's current rate;

c. Corporate overhead at the Company's current rate;

d. Reimbursement of net present value of federal tax expenses attributable to meter upgrade.

Charges hereunder will be increased by the applicable percentage as explained in General Rule 30.

GENERAL RULES

19. Retail Access Program – Continued

19.3 Energy Service Company ("ESCO") Participation - Continued

19.3.6 Consolidated Billing and Payment Processing Services

Subject to limitations set forth below, an ESCO and the Company may agree for one party to perform consolidated billing and payment processing services on behalf of the other. Billing and payment processing services are governed by the terms and provisions of retail access billing and payment processing practices as specified in the UBP and by such other terms and conditions not inconsistent with otherwise applicable laws, regulations, and PSC orders.

If an ESCO and the Company agree for one party to perform consolidated billing and payment processing services on behalf of the other, the Company and ESCO will execute a billing services agreement. The Company will provide Consolidated Bills in connection with the Purchase of Receivables ("POR") program pursuant to the Consolidated Utility Billing Service and Assignment Agreement executed by the Company and the ESCO; provided, however, that Consolidated Bills are not available to Customers served under Special Provision G of SC 9 for all or part of their energy requirements. Consolidated Bills for residential Customers are limited to Company-issued Consolidated Bills. An ESCO may provide Consolidated Bills for its Customers who are not Residential Customers.

Under the POR program, the Company shall remit to the ESCO undisputed ESCO charges billed to its customers, reduced by the POR Discount Percentage. The POR Discount Percentage shall consist of an Uncollectible Bill Percentage, a Risk Factor, a Credit and Collections component and an Incremental Cost component associated with POR program administration. The four components will be set annually and become effective each January 1. The Uncollectible Bill Percentage shall be based on the Company's actual uncollectible bill experience applicable to electric and gas customers for the 12-month period through the previous September. The Risk Factor shall be equal to 15 percent of the Uncollectible Bill Percentage. The Credit and Collections component will include: (a) a percentage determined by dividing the Company's credit and collection expenses attributable to retail access customers whose ESCOs participate in the Company's POR program by the estimated electric supply costs to be billed on behalf of ESCOs through the POR program; and (b) effective January 1, 2019, a percentage that reflects a reconciliation of prior periods' credit and collections expenses and recoveries, plus interest (calculated at the Other Customer Capital Rate). The Incremental Cost component shall be set to 0.15 percent.

A statement showing the POR Discount Percentage will be filed with the Commission on no less than three days' notice.

If the Company determines, in its sole discretion, that an ESCO is not in compliance with the dispute resolution procedure specified in the Consolidated Utility Billing Service and Assignment Agreement, the Company will assess a charge to the ESCO equal to the amount disputed by the Customer.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.2 Interconnection and Operation

To receive Standby Service, the generator may be connected either for: (a) parallel operation with the Company's service, or (b) isolated operation with standby service provided by the Company by means of a double-throw switch.

Customers who take Standby Service are subject to the interconnection and operation requirements as described in General Rule 8.4.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates – Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.3 Customers Exempt from Standby Service Rates - Continued

20.3.2 Customers With Designated Technologies

A Customer With Designated Technologies will be billed under Standard rates, unless the Customer makes a one-time election in writing to be billed under Standby Service rates. A Customer With Designated Technologies who uses Efficient CHP with an aggregated capacity greater than 1 MW, up to 15 MW, will be exempt from Standby Service rates for a period of four years from the in-service date, unless the Customer makes a one-time election in writing prior to the end of its four-year exemption period to be billed prospectively under Standby Service rates.

Definitions:

"Customer With Designated Technologies" for purpose of this General Rule means a Customer with a Contract Demand of 50 kW or greater whose on-site generation has a total nameplate rating equal to more than 15 percent of the maximum potential demand from all sources and:

(a) exclusively uses fuel cells, wind, solar thermal, photovoltaics, sustainably-managed biomass, tidal, geothermal, and/or methane waste, and its on-site generation facility has an in-service date between July 29, 2003 and May 31, 2023; or

(b) uses efficient combined heat and power ("CHP") that does not exceed 1 MW of capacity in aggregate, and its CHP generation facility has an in-service date between July 29, 2003 and May 31, 2021; or

(c) uses efficient CHP with an aggregated capacity greater than 1 MW, but no more than 15 MW, its CHP generation facility has an in-service date between May 31, 2015 and May 31, 2021, and meets additional requirements specified in General Rule 20.3.4(a); or

(d) uses Electric Energy Storage with maximum capability up to and including 1 MW; and

(e) meets all of the following requirements if CHP is used: (i) has an annual overall efficiency of no less than 60 percent based on the higher heat value of the fuel input, (ii) has a usable thermal energy component that absorbs a minimum of 20 percent of the CHP facility's total usage annual energy output, (iii) serves no more than has 100 percent of the Customer's maximum potential demand, and (iv) is designed to have maximum NOx emissions of 1.6 lbs/MWh; provided, however, that the facility is designed to have maximum NOx emissions of 4.4 lbs/MWh if that Customer was exempt from Standby Service rates as of January 1, 2017, or had an accepted interconnection application and/or air permit application as of that date.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.3 Customers Exempt from Standby Service Rates - Continued

20.3.3 Customers With Targeted Exemptions - Continued

(b) A Customer who newly installs battery storage of no less than 50 kW on or after January 1, 2017, may apply for an exemption from Standby Service rates provided that the Customer:

(i) submits a completed application for interconnection of its new battery storage system as described in General Rule 20.2 by December 31, 2019, and commences operation of the storage system by December 31, 2021; and
(ii) meets the requirements of General Rule 20.3.4.

Each eligible Customer will be exempt from Standby Service rates for ten years from the date the battery storage project commences operation. Such Customer will also receive shadow billing, for informational purposes, at rates under Rider Q - Option B during the term of such rates, and at the then-effective Standby Service rates thereafter, unless the Customer makes a one-time election to be switched to billing either under Rider Q or the then-effective Standby Service rates.

Applications made under General Rule 20.3.3(b) shall not exceed 25 MW of new battery energy storage projects. If Customers served under this General Rule 20.3.3(b) switch to the Standby Rate Pilot under Rider Q or Standby Service rates, the MW withdrawn by such Customers will not be available to those Customers or any other Customers under this General Rule 20.3.3(b).

20.3.4 Additional Requirements

The following requirements are applicable to Customers exempt from Standby Service rates pursuant to General Rule 20.3.2(c) and General Rule 20.3.3:

(a) Customers With Designated Technologies who use Efficient CHP with an aggregated capacity greater than 1 MW and Customers With Targeted Exemptions must comply with the following additional requirement in order to be exempt from Standby Service rates: the output of the CHP generating facility and/or the charging usage and discharge output of the battery storage facility, as applicable, must be separately metered using an Output Meter (as defined in General Rule 2) that the Customer arranges to be furnished and installed at Customer expense. The Company will assess the charge specified in General Rule 16.4 if the Customer's communications equipment is not operational and may transfer the Customer to Standby Service rates if there are two or more instances of Customer caused failed communications service in any calendar year.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.3 -Continued

(A) Where the Customer Establishes the Contract Demand

(1) A Customer who chooses its own Contract Demand may revise the Contract Demand by giving written notice to the Company, which must be received no less than ten days before the beginning of the first billing period for which the revised Contract Demand shall be applicable. A Customer may revise its Contract Demand downward once every 12 months if the Customer demonstrates, based on an engineering analysis submitted to the Company, that electricity-consuming equipment is removed or abandoned in place or that permanent energy-efficiency or load-limiting equipment is installed. No retroactive adjustment will be made for a reduction in the Contract Demand level. A Customer may revise its Contract Demand upward at any time for a prospective billing period.

(2) The Company has final authority to approve or modify the Contract Demand on an account receiving output from a generating facility: (a) served under General Rule 20.4.5 or General Rule 20.4.6 or General Rule 20.4.7; or (b) installed on or after March 1, 2014, in a new premises or upgraded premises (i.e., where the Customer requires additional electric service to meet a higher load or increased capacity requirements regardless of the output of the generating facility). The Company will approve or modify the Contract Demand based on the principles used by Company to establish Contract Demand pursuant to General Rule 20.4.3(B).

(3) Where the Company does not have final authority to approve or modify the Contract Demand (i.e., the Contract Demand is set by a Customer either prior to March 1, 2014, or for an existing building that does not require additional electric service), the Customer will be subject to a surcharge if the monthly maximum demand exceeds the Contract Demand by more than 10 percent. Such surcharge will apply to the current monthly bill for the portion of the demand that is in excess of the Contract Demand. The surcharge will apply as follows:

(a) If the monthly maximum demand exceeds the Contract Demand by more than 10 percent but less than 20 percent, the surcharge will be equal to 12 times the monthly Contract Demand Delivery Charge for the excess demand; and

(b) If the monthly maximum demand exceeds the Contract Demand by 20 percent or more, the surcharge will be equal to 24 times the monthly Contract Demand Delivery Charge for the excess demand.

The Contract Demand Delivery Charge is equal to the Contract Demand Delivery Charge per kW.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.5 A low-tension Customer taking service from a private generating facility having a total nameplate rating of over 2 MW may take Standby Service by connecting the facility to the Company's high-tension distribution system, provided the connection and operation of such facility do not jeopardize the safety or operation of the Company's system, facilities or other Customers and all of the following conditions are met: (a) the facility meets eligibility criteria for designation as "combined heat and power" pursuant to the order of the Public Service Commission, dated January 23, 2004, in Case 02-E-0781, except with respect to maximum generating capacity; (b) the service interconnection is made to an interior distribution installation, pursuant to General Rule 5.6.2; (c) all the electricity delivered by the Company and supplied by the Customer's generator serves that Customer's single low tension account; (d) the generating facility is connected at high tension voltage (as specified in General Rule 4.6) on the Company's side of the revenue meter; (e) the high-tension meter on the generator's output is adjusted for transformer losses; and (f) the cost to the Company of the installation is no greater than it would be if the generating facility were connected at low-tension voltage on the Customer's side of the meter, and the configuration of Company equipment is the same under either the high-tension or low-tension connection.

The Customer will be billed under Standby Service rates, as modified below:
(a) There will be an additional Customer Charge of $50.00 per billing period, exclusive of the Increase in Rates and Charges, to cover incremental billing and administrative costs associated with providing service to this type of installation. (b) The per-kWhr charges described in General Rule 26 will be applied to the Customer's total kWhr usage registered on the low-tension meter(s) less the kWhr registered on the high-tension meter measuring the private generating facility's output (adjusted for losses). (c) The daily maximum demand used in determining the As-used Daily Demand Delivery Charges will be the highest net integrated demand, i.e., the difference between the Customer's low-tension registered demand and the high tension registered demand measuring the generator's output (adjusted for losses). (d) The monthly maximum demand used in determining Contract Demand exceedances under section (A) of General Rule 20.4.3 will be the low-tension maximum demand.

A Customer taking service under this provision may take service under SC 11 if the kWhr export of the generating facility exceeds the total kWhr usage registered on the low-tension meter(s).

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.5 - Continued

A change to the Customer's low tension account must be requested between February 1 through March 1 or August 1 through September 1 of each year. Such changes will be effective for bills issued with a "from" date in May or November, respectively.

The request must be made by submitting a revised "Application for Net Metering or Standby Service and/or Buy-Back Service" set forth in Application Form G in the General Rules.

The Customer's active low tension account must complete at least 12-months of service under General Rule 20.4.5.

No credits will be applied if the Customer ceases to have a low tension account or ceases to own or operate the generating facility. If the Customer's low tension account is closed, its credits will be forfeited unless the Company receives a new Application for Net Metering or Standby Service and/or Buy-Back Service within 30 days of the account's closure.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 A Customer with a private generating facility connected to the Company's high tension distribution system (as specified in General Rule 4.6) may use the output of the generating facility to supply two or more Standby Service accounts, as long as all of the following conditions are met:

(a) Eligibility:

(1) Standby Service Accounts:

(a) The Standby Service accounts designated by the Customer and the account associated with export of the generating facility must be all established in a single Customer's name ("Single Party Offset"); or

(b) The generating facility and the Standby Service accounts designated by the Customer to receive the output of the generating facility may be established in two or more Customer names ("Multi-party Offset"), provided all of the following conditions are met:

(i) at least one of the Standby Service accounts must be in the same Customer name as the owner or operator of the generating facility (the "Sponsor") and have a Contract Demand equal to 10 percent or more of the nameplate rating of the generating facility;
(ii) the Sponsor will be responsible for coordinating the interconnection and operation of the generating facility with the Company; and
(iii) at the time of application under the Multi-party Offset, the Sponsor must submit the following complete forms at least 30 days prior to commencement of service: (a) a Multi-Party Offset Recipient Participation Form signed by the Customer of record for each Recipient Account, and (b) a Multi-Party Offset Percentage Allocation Form signed by the Sponsor. Both forms will be available on the Company's website.

(2) The generating facility must: (i) have a total nameplate rating of over 2 MW; and (ii) meet eligibility criteria for designation as efficient "combined heat and power" pursuant to the order of the Public Service Commission, dated January 23, 2004, in Case 02-E-0781, except with respect to maximum generating capacity. The generating facility may have more than one generating unit so long as the aggregate nameplate rating conforms to (i) above.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 - Continued

(a) - Continued

(3) The generating facility and the Standby Service accounts must all be located within a single “premises.” “Premises” is defined as follows, for purposes of General Rule 20.4.6 only:

(a) Under Single Party Offset, “premises,” means “a parcel of land; or more than one building and/or parcel of land proximate to each other if there is common use, whether or not such buildings or parcels are separated by public or private roads.” The accounts of a Customer whose buildings or parcels of land are not physically interconnected may meet the definition of a single “premises” upon the Customer’s demonstration of common use to the Company.

(b) Under Multi-party Offset, “premises” means “either (i) a single building or (ii) multiple buildings in which each Customer is connected to the generating facility by a private thermal loop that delivers steam, hot water, or chilled water.”

(4) The Standby Service accounts supplied by the output of the Sponsor’s generating facility (“Recipient Accounts”) shall not be served by any other source of generation, except as permitted under General Rule 8.2, and shall not participate under Rider R.

(5) At least one of the Standby Service accounts must be connected to the Company’s low tension distribution system.

(6) Each Standby Service account must be separately metered. The export of the generating facility must also be separately metered using an Output Meter (as defined in General Rule 2) that is furnished and installed at Customer expense. (The cost of the Output Meter, if provided by the Company, will be recovered as part of the Interconnection Charge.)

(7) Service must be taken under SC 11 (or an applicable wholesale tariff) if the export of the generating facility exceeds the aggregated registered kWhr usage on the Standby Service accounts. Otherwise, at the Company’s discretion, the Company will terminate service under General Rule 20.4.6 or make no payments for the export.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 - Continued

(b) Interconnection:

The interconnection will be subject to the interconnection requirements and charges specified in General Rule 20.2. In addition, the interconnection must be technically and economically practicable, and the connection and operation of such facility shall not jeopardize the safety or operation of the Company's system, facilities or other Customers.

(c) Accounts Supplied by the Generating Facility's Output:

(1) Each account must be eligible for billing under Standby Service rates and must be billed under the Standby Service rate applicable to that individual account.

(2) Accounts served under General Rule 20.4.6 must be either all Full Service or take Supply service from a single non-Company source of electric power supply.

(3) If the accounts are not Full Service accounts, all supply in excess of that supplied by the private generating facility must be supplied by a single entity.

(4) No account served under General Rule 20.4.6 may be served under the PASNY Rate Schedule or any economic development program specified in General Rule 11.

(5) None of the accounts may receive Consolidated Billing (described in General Rule 19.3.6).

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 - Continued

(c) Accounts Supplied by the Generating Facility's Output: - Continued

(6) A request to add a new building commencing service to be supplied by the generating facility's output may be made at any time during the year and will be effective for bills issued for the second billing cycle after the request is made. Changes to Recipient Accounts must be requested between February 1 through March 1 or August 1 through September 1 of each year. Such changes will be effective for bills issued with a "from" date in May or November, respectively.

For Single Party Offset, the request must be made by submitting a revised "Application for Net Metering or Standby Service and/or Buy-Back Service" set forth in Application Form G in the General Rules. For Multi-party Offset, the request must be made by submitting: (a) a Multi-Party Offset Recipient Participation Form signed by the Customer of record for each Recipient Account, and (b) a Multi-Party Offset Percentage Allocation Form signed by the Sponsor.
An active Recipient Account must complete at least 12-months of service under Single Party Offset or Multi-party Offset.

No credits will be applied if the Sponsor ceases to have a Recipient Account or ceases to own or operate the generating facility. If a Recipient Account is closed, its credits will be forfeited unless the Company receives a new Multi-Party Offset Percentage Allocation Form signed by the Sponsor within 30 days of the account's closure.

(d) Contract Demand for Each Account Supplied by the Generating Facility's Output:

The Contract Demand for each account will be determined based on the maximum potential demand on the Company's system to serve that individual account, including the delivery of supply from all sources.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 - Continued

(e) Billing Applicable to Each Account Supplied by the Generating Facility's Output:

(1) Allocated As-used Generator Demand and Allocated Generator Supply will be determined for each metered interval. Adjustments will be made for transformation losses as applicable. For purposes of this General Rule, the following definitions apply:

For Accounts Supplied Under the Single Party Offset

"Allocated As-used Generator Demand" means, for each account supplied by the generating facility's output, the demand registered on the account's meter(s) multiplied by the lower of: (a) 1 or (b) the ratio of the demand registered on the high-tension meter(s) measuring the generating facility's output to the sum of demands registered on the meters of all Standby Service accounts supplied by the generating facility's output.

"Allocated Generator Supply" means, for each account supplied by the generating facility's output, the total kilowattthours registered on the account's meter(s) multiplied by the lower of: (a) 1 or (b) the ratio of the total kilowatthours registered on the high-tension meter(s) measuring the generating facility's output to the sum of the kilowatthours registered on the meters of all Standby Service accounts supplied by the generating facility's output.

For Accounts Supplied Under the Multi-party Offset

"Allocated As-used Generator Demand" means, for each Recipient Account, the lower of (a) the demand registered on the Recipient Account or (b) the demand registered on the high-tension meter(s) measuring the generating facility's output multiplied by the Recipient Account's Percentage Allocation. If the generating facility's output multiplied by the Recipient Account's Percentage Allocation exceeds the demand registered on the Recipient Account, the excess amount shall neither be redistributed to other accounts nor carried forward to the succeeding billing period.

"Allocated Generator Supply" means, for each Recipient Account, the lower of (a) the total kilowatthours registered on the Recipient Account's meter(s) or (b) the total kilowatthours registered on the high-tension meter(s) measuring the generating facility's output multiplied by the Recipient Account's Percentage Allocation. If the generating facility's output multiplied by the Recipient Account's Percentage Allocation exceeds the kilowatthours registered on the Recipient Account's meter(s), the excess amount shall be credited to the extent described in General Rule 20.4.6(a)(7).

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 – Continued

(e) - Continued

(1) For Accounts Supplied Under The Multi-party Offset - Continued

“Percentage Allocation” means the percentage of the generating facility’s output that the Sponsor has allocated to each Recipient Account under the Multi-party Offset. A single percentage will be applied to both the Allocated As-used Generator Demand and the Allocated Generator Supply. The Percentage Allocations must total 100 percent, of which the Sponsor must establish: (a) a Percentage Allocation of 10 percent or more to a single Recipient Account in the Sponsor’s name; and (b) a Percentage Allocation of no less than 5 percent or more than 90 percent to each additional Recipient Account.

(2) Each account supplied by the generating facility’s output will be billed under Standby Service rates, as modified below:

(i) An additional Customer Charge of $50.00 per account per billing period, exclusive of the Increase in Rates and Charges, will be applicable to cover incremental billing and administrative costs associated with providing service under this provision.

(ii) The per-kWhr delivery charges and adjustments described in General Rule 26 will be applied to the total kilowattthours registered on the account’s meter(s) reduced by the Allocated Generator Supply for each metered interval (adjusted for losses as applicable).

(iii) For each metered interval, the registered demand on the account’s meter(s) will be reduced by the Allocated Generator Demand for purposes of determining the daily maximum demand that is used for billing As-used Daily Demand Delivery Charges.

(iv) If the Customer purchases supply from the Company, the per-kWhr supply charges and adjustments described in General Rule 25 will be applied to the total kilowatthours registered on the account’s meter(s) reduced by the Allocated Generator Supply for each metered interval (adjusted for losses as applicable).

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.6 - Continued

(e) - Continued

(3) The Allocated As-used Generator Demand and Allocated Generator Supply will be assumed to be zero for time periods where there is insufficient interval data available to ascertain that the Generating Facility supplied output to any associated Standby Service account.

Bills may be estimated pursuant to General Rule 10.7. If interval data is estimated on a Standby Service account, that data will be used in the calculation of the Allocated As-used Generator Demand for all other accounts. If actual data later becomes available, the account will be rebilled based on the actual registered demand on the meter less the previously determined allocated As-used Generator Demand for such account.

(f) The Customer will be assessed a Reactive Power Demand Charge per kVar registered on the generating facility's export meter(s) at the time of the kW maximum demand; provided, however, that if the meter registers no kW demand, the charge per kVar will be applied to the highest kVar recorded during the billing period. Applicable charges are specified in General Rule 10.11(4).

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.4 Billing under Standby Service Rates - Continued

20.4.7 A low-tension Customer that is the sole customer receiving service under a single account from a multi-metered interior distribution installation, pursuant to General Rule 5.6.2, or Company-owned equivalent equipment, and meeting the requirements for coincident demand as specified in General Rules 6.2.2 and 6.6, taking service from a private generating facility having a total nameplate rating of not more than 5 MW may take Standby Service by connecting the facility behind a single meter and operating the facility such that facility power exports past such meter to the Company's low-tension distribution system to provide kW and kWhr support to the Customer's other metered load within the interior distribution installation or Company-owned equivalent. The connection and operation of such facility shall not jeopardize the safety or operation of the Company's system, and subject to safety and reliability considerations, Customers may be required to install mitigation technologies (e.g., fault limiting capability), at the Customer's cost. The Customer and its private generating facility must meet all of the following conditions: (a) the facility meets eligibility criteria for designation as "combined heat and power" pursuant to the order of the Public Service Commission, dated January 23, 2004, in Case 02-E-0781, except with respect to maximum generating capacity; and (b) the generating facility is interconnected to a single service connection of an interior distribution installation or Con Edison owned equivalent; and (c) no other Customers are served directly by the interior distribution installation or Con Edison owned equivalent, unless the service is submetered pursuant to Rider G.

The Customer will be billed under Standby Service rates, as modified below:

(i) There will be an additional Customer Charge of $50.00 per billing period, exclusive of the Increase in Rates and Charges, to cover incremental billing and administrative costs associated with providing service to this type of installation.

(ii) Any excess kWhr and kW export from the service connection to which the Customer's generating facility is connected will be netted against the usage on the Customer's other service connections on an interval metered basis.

A Customer taking service under this provision may take service under SC 11 if the kWhr export of the generating facility exceeds the total kWhr usage registered on all of the meter(s).

The Customer must complete at least 12-months of service under General Rule 20.4.7, unless the account is closed.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.5 Delivery Charges under Standby Service Rates

20.5.1 The delivery charges applicable to all Customers billed under the Standby Service rates of SC 5, 8, 9, 12 or 13 include, but are not limited to, a Customer Charge per month, a Contract Demand Delivery Charge, and an As-used Daily Demand Delivery Charges. Where meter data is not available, the As-used Demand will be based on the best available data. For a Customer that is a Wholesale Generator, As-used Demand Charges will not apply to demand experienced during any period when it self-supplies all of its energy needs from the load side of the meter.

20.5.2 A Customer that is a Wholesale Generator and takes Standby Service for Station Use shall pay delivery charges for its Standby Service exclusive of transmission charges. The charges are shown under Rates IV and V of SC 9.

20.5.3 The Standby Performance Credit was established by the Commission's Order of June 19, 2015, in Case 13-E-0030, and replaced by the Standby Reliability Credit, in Case 16-E-0060. The Standby Performance Credit for each eligible Customer who requested the credit in 2016, by October 3, will be applied to the Customer's successive 12 monthly bills commencing November 2016.

20.5.4 A Standby Reliability Credit ("Credit") is available to specified Customers billed under Standby Service rates based on their ability to reduce their demand below the Contract Demand level during the Measurement Period. The Credit is not available to Customers served under the Value Stack Tariff as described in Rider R of this Rate Schedule, Customers with Grid-connected Electric Energy Storage systems, and Customers without generating facilities. To be eligible for the Credit: (a) the generating facility's output must be separately metered using an Output Meter (as defined in General Rule 2) that the Customer arranges to be furnished and installed at Customer expense prior to the beginning of the Summer Period for which the Customer requests a Credit; and (b) the output of the generating facility must be connected at a voltage lower than 100 kV.

For purposes of General Rule 20.5.4 only, the following definitions apply:

"Measurement Hours" are Monday through Friday, 10 AM to 10 PM, during the 2017 Summer Period and Monday through Friday, 8 AM to 10 PM, each Summer Period thereafter.

"Measurement Period" is the Measurement Hours during the previous two consecutive full Summer Periods; provided, however, that the first year in which a Customer seeks a Credit, the Measurement Period is the Measurement Hours during the previous full Summer Period only. The Measurement Period will exclude Outage Events, regardless of cause, as selected by the Customer, as well as holidays (i.e., Independence Day (observed) if it falls on a weekday and Labor Day).

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.5 Delivery Charges under Standby Service Rates - Continued

20.5.4 – Continued

"Outage Events" are up to three time blocks for each Summer Period that, in aggregate, are comprised of no more than five 24-hour periods, excluding weekends and holidays. If a time block contains a period of less than 24 hours, the time period will be rounded up to the next 24 hours (i.e., the 24-hour periods cannot be applied on a partial basis). If a time block encompasses a holiday or weekend, the start of the 24-hour period on the day prior to the holiday or weekend until the same hour the next business day will be considered to be a single 24-hour time period.

"Summer Period" is June 15 through September 15 in 2017, and June 1 through September 30 each year thereafter.

A Customer seeking a Credit must request such Credit by October 10 of each year for which the credit is sought and, at the same time, specify the Outage Events the Customer requests to be excluded from the Measurement Period. If October 10 falls on a weekend or holiday, the Company will accept requests until the next business day. If service is taken under the Single Party or Multi-party Offset provision of General Rule 20.4.6, the Credit will be applied to each Standby Service account supplied by the generating facility's output.

The Credit for any Measurement Period will be equal to the product of: (a) the Reliability Adjustment and (b) the Contract Demand Delivery Charge per kW that is in effect on October 1 of the year in which the Credit is determined. The Reliability Adjustment is equal to the Customer's Contract Demand less the highest kW demand recorded on the meter(s) used for monthly billing (net of generation) during the Measurement Period. If the Customer receives a reduction in Contract Demand Charges for delivery service (e.g., under Rider J or Special Provision H of SC 9), the Contract Demand Charge used to calculate the Credit will be reduced accordingly.

The Credit will be applied to the successive 12 monthly bills of the Standby Service account commencing in November until the following October.

The Reliability Adjustment, as defined above, will only be used for the purposes of determining the Standby Reliability Credit.

GENERAL RULES

20. Standby Service and Standby Service Rates - Continued

20.8 Customers taking Standby Service Prior to February 20, 2012

Customers who were served under SC 3 – Back-up Service or SC 10 - Supplementary Service of P.S.C. No. 9 - Electricity, including Special Provision A of either SC, on February 1, 2004, were automatically transferred to Standby Service under SC 14-RA – Standby Service of P.S.C. No. 2 – Retail Access. Customers who were served under SC 14-RA of P.S.C. No. 2 – Retail Access on February 20, 2012, were automatically transferred to service under this Rate Schedule under the rates, terms and provisions applicable to Standby Service at that time.

20.9 Applications

Except for Customers automatically transferred to SC 14-RA of the Retail Access Rate Schedule upon the cancellation of SC 3 and SC 10 of the Schedule for Electricity – P.S.C. No. 9, requests for Standby Service shall be made in writing. Applicants for Standby Service must submit a completed "Application for Net Metering or Standby Service and/or Buy-Back Service" set forth in Application Form G in the General Rules, including applications made by Sponsors under the Multi-party Offset pursuant to General Rule 20.4.6, but excluding applications made by Recipient Accounts under the Multi-party Offset. Applicants for Standby Service by Recipient Accounts under Multi-party Offset must submit a completed Multi-Party Offset Participation Form. Rate Choice Customers must make an election in writing to change to or from Standby Service rates.

GENERAL RULES

21. Liability

21.1 Continuity of Supply

The Company will endeavor at all times to provide a regular and uninterrupted supply of service, but in case the supply of service shall be interrupted or irregular or defective or fail from causes beyond its control or through ordinary negligence of employees, servants or agents the Company will not be liable therefor.

The Company may, without liability therefor, interrupt service to any Customer or Customers in the event of emergency threatening the integrity of its system, if, in its sole judgment, such action will prevent or alleviate the emergency condition.

Notwithstanding other limitations of liability contained in this tariff, the Company will compensate Customers for losses, of the type and to the extent set forth below, which result from power failures attributable to malfunctions in the Company's lines and cable of 33 kV or less and associated equipment as set forth below.

The Company will reimburse residential Customers served directly under SC 1, and those served indirectly under SC 8, SC 12, and SC 13, as follows: (1) for actual losses of food spoiled due to lack of refrigeration, up to $250 upon submission of an itemized list and over $250 upon submission of an itemized list and proof of loss, up to a maximum of $580 for any one Customer for any one incident; and (2) for actual losses of perishable prescription medicine, spoiled due to lack of refrigeration, upon submission of an itemized list and proof of loss and, if requested by the Company, submission of authorization to enable the Company to verify the claimed loss.

The Company will reimburse Customers under other SCs for actual losses of perishable merchandise spoiled due to lack of refrigeration, upon submission of an itemized list and proof of loss, up to a maximum of $11,460 for any one Customer for any one incident.

The Company's total liability under this section is limited to $15,000,000 per incident. In the event the total aggregate amount claimed under this provision exceeds $15,000,000, the approved amounts of individual claims will be adjusted downward on a pro rata basis to the extent required to hold payments to a total of $15,000,000. All claims under this section must be filed with the Company within 30 days from the date of occurrence.

GENERAL RULES

24. Service Classification Riders (Available on Request)

Subject to the terms, conditions and availability of service under each Rider, Customers taking service under this Rate Schedule may be served under the following Riders:

Rider	Applicable to the Following Service Classifications	Comments
A	1, 2, 5, 6, 8, 9, 11, 12, 13	Receivers/trustees
B	1, 2, 5, 8, 9	Conjunctional billing (no applications after May 31, 1959)
C	1, 2, 8, 9	Interconnecting buildings (no applications after May 31, 1959)
D	1, 2, 8, 9, 12	Fire alarms/signals
E	2, 5, 9, 12	Series metering (no applications after February 28, 2014)
F	1, 2, 9	Series metering (no applications after February 28, 2014)
G	2, 8, 9, 12, 13	Submetering
H	1, 2, 8, 9, 12	On-bill recovery of NYSERDA loan installments
I		[RESERVED FOR FUTURE USE]
J	9	Business incentive rate
K	N/A	Attachments by CATV and telecommunications companies
L	1, 2, 8, 9, 12, 13	Direct load control. Also applicable to PASNY Customers
M	5, 8, 9, 11, 12, 13	Hourly pricing for Full Service Customers
N	9	Mobile generators in lower Manhattan
O		[RESERVED FOR FUTURE USE]
P		[RESERVED FOR FUTURE USE]
Q	5, 8, 9, 11, 12, 13	Standby Rate Pilot. Also applicable to PASNY Customers
R	1, 2, 5, 8, 9, 11, 12, 13	Net metering and Value Stack Tariff for customer-generators
S	1	Low income program
T	1, 2, 5, 8, 9, 11, 12, 13	Demand response. Also applicable to Aggregators and PASNY Customers
U	Authority Customers and Public Entities as defined in Public Authorities Law §1005 subdivisions 27.(g) and 17.(b), respectively	NYPA Supply Service
V		[RESERVED FOR FUTURE USE]
W		[RESERVED FOR FUTURE USE]
X	N/A	Facilities used for telecommunications
Y	9	High load-density service. Also applicable to PASNY Customers
Z	1	SC 1 Innovative Pricing Pilot
AA	2	SC 2 Innovative Pricing Pilot
AB	1	Smart Home Rate
AC	1, 2, 5, 8, 9, 11, 12, 13	Term- and Auto-Dynamic Load management programs. Also applicable to Aggregators and PASNY Customers

The following Riders may not be applied to Customers taking Standby Service: D, E, F, and R.
The following Riders may not be applied to Retail Access Customers: M, U, and AB.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER D - OPERATION OF FIRE ALARM OR SIGNAL SYSTEM

Applicable to SCs 1, 2, 8, 9, and 12,
except for Customers taking Standby Service

It is further understood and agreed that the Company will furnish service hereunder for the operation of fire alarm or signal systems on an unmetered basis at the following rates and charges:

1. For service connection..$150.01

2. For each gong or signal circuit, or combination of gong or signal circuits, in which there is a continuous flow of current of not over 125 milliamperes, the voltage of the supply being approximately 120 volts, or the equivalent (taken as 15 volt-amperes) at other supply voltages,

   when the Customer is also taking
   metered service under this agreement ....$10.29 per calendar month

   when no metered service is being
   supplied under this agreement ....$30.81 per calendar month

3. For each additional 125 milliamperes (or equivalent) of
   continuous flow, or fraction thereof, an additional charge of.............................$10.29 per calendar month

Billing and Payment Processing Charge

Charges are as shown in General Rule 26.3.

Increase in Rates and Charges

The rates and charges under this Rider are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE

Applicable to SC 2 and SC 9
(Subject to the provisions thereof)

(A) Applicability

To non-governmental Customers, except for customers under the Electric Vehicle Quick Charging Station Program, eligible for service under SC 9 and, for COVID-19 BIR only, under SC 2, and meeting the requirements of this Rider. SC 2 Special Provision (C) and SC 9 Special Provision (C) are not applicable to Customers served under this Rider.

(B) Business Incentive Rate ("BIR") Program Components and Availability

(1) New York City and Westchester Comprehensive Package of Economic Incentives ("New York City Comprehensive Package" and "Westchester Comprehensive Package"): This BIR component is provided to Customers receiving economic development benefits in the form of a Comprehensive Package of Economic Development Incentives in exchange for a long-term commitment to locate, remain, or relocate in the Company's service area pursuant to a contract with state or local authorities.

"Comprehensive Package of Economic Incentives" is defined as: (a) a separately-negotiated comprehensive package of economic incentives of at least five-years' duration conferred by the local municipality or state authorities to maintain or increase employment levels in the service area. Such incentives must include substantial tax or similar incentives, such as an allocation under the Recharge New York ("RNY") program or the START-UP NY program and/or certification of eligibility for energy rebates under the New York City Energy Cost Savings program ("ECSP"); or (b) low-cost financing conferred by the local municipality, state authorities, the federal government, or entities which are tasked to provide federal financing, stimulus funds, or make similar investments to not-for-profit institutions utilizing space for Biomedical Research (as defined below under the Biomedical Research Program). Customers eligible under both the Comprehensive Package and the New and Vacant Program are considered eligible for the Comprehensive Package only.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE - Continued

(B) Business Incentive Rate ("BIR") Program Components and Availability – Continued

(4) Business Incubators and Business Incubator Graduates: This BIR component is available to Business Incubators for BIR load of up to 750 kW and Business Incubator Graduates for BIR load of up to 500 kW. If the Business Incubator or Business Incubator Graduate is a tenant in a redistribution building, its usage must be a minimum of 10 kW.

"Business Incubator" is defined as a facility that supports the launch and growth of start up and fledgling businesses by providing: (a) a workspace at discounted rates; (b) access to a network of successful entrepreneurs and support organizations through a program of events and an advisory board; and (c) an array of targeted resources and services. "Business Incubator Graduate" is defined as a start up or fledgling business that was a resident in a Business Incubator and left the Incubator in order to grow or expand its business. Businesses that are dismissed from the Incubator are excluded from this definition.

(5) Electric Vehicle ("EV") Quick Charging Station Program: This BIR component is available to owners of EV quick charging stations, including governmental customers, with a minimum aggregate charging capacity of 100 kW and a maximum aggregate demand of 2,000 kW. Stations must be newly constructed EV quick charging stations with no more than 10 kW of ancillary (non-EV charging) load. To be eligible, the stations must be publicly accessible, such as stations located at: supermarkets, malls and retail outlets, train stations, hotels, restaurants, and parking garages and parking lots where the EV quick charging station is open to the general public and will be used by a wide variety of users.

(6) COVID-19 BIR: This BIR component is available to Small Business Customers that received government assistance in the form of grants, loans or other qualified assistance from city, county, state or federal government agencies. The government assistance shall be directly related to the Customer demonstrating that it experienced financial challenges due to the impacts of the COVID-19 pandemic.

In the context of COVID-19 BIR, a Small Business Customer is defined as a Customer that has an existing SC 2 or SC 9 Rate I account with a monthly maximum demand less than 30 kW in the past 12 consecutive months.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE - Continued

(C) Eligibility

(1) Energy Audits

Customers may take service under this Rider only if an energy efficiency audit has been performed either by NYSERDA or other governmental authority that administers energy efficiency programs or by an independent third party (e.g., a qualified energy audit firm under the Company's Small Business Direct Install Program) or Customer personnel capable of conducting a comparable audit, except as follows:

(a) a Business Incubator must have an energy efficiency audit performed within six months of applying for service under this Rider;
(b) a Business Incubator Graduate must have the energy efficiency audit performed prior to taking service under this Rider, but no more than six months after signing a lease or obtaining a deed; and
(c) an energy efficiency audit will not be required under the EV Quick Charging Station Program or COVID-19 BIR.

Business Incubators and Business Incubator Graduates must provide proof to the Company that: (a) they have had an energy audit performed, as described above; (b) they have installed the energy efficiency measures recommended in the audit or provided a reasonable explanation as to why recommended measures were not implemented; and (c) if they use 100 kW or more per month, they received paid rebates, if any. To remain eligible for service under this Rider, a Business Incubator must have an energy efficiency audit conducted once every five years and provide the proof specified above.

(2) Distribution Facilities Cost Test

An application for service under this Rider shall not be accepted if the Company is required to incur substantial costs for additional distribution facilities to serve the premises in which the Customer is located. The Company shall determine whether the cost of such distribution facilities is substantial in the following manner:

The investment in additional distribution facilities necessary and attributable to providing service to an eligible Customer in the premises shall be compared to an amount that is four times the estimated annual Pure Base Revenue that would be obtained from the Customer under the rates of the appropriate Service Classification. If the investment in distribution facilities exceeds such amount, the applicant will not qualify for service under this Rider. The applicant may qualify for service by making a non-refundable payment or other contribution satisfactory to the Company towards the investment in distribution facilities that would result in the applicant meeting the foregoing economic test. Such payment or other contribution must be made in advance of taking service.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE - Continued

(C) Eligibility - Continued

(3) Electric Chiller Reduction for Customers Located Near a Steam Main

Customers who are located within 250 feet of a steam main in the Borough of Manhattan and receive allocations of power on or after April 1, 2008, under either the New and Vacant Program or the New York City Comprehensive Package Program, will receive a reduction in their delivery service kW and kWhr eligible for bill reductions under this Rider for the months of June through September if they have electric and/or hybrid electric chillers ("Electric Chiller Reduction"). The Company will determine the kW and kWhr portions of the Electric Chiller Reduction based on information supplied by the Customer, including the nameplate rating of the chilling equipment and equipment efficiency information ("cut sheets").

For each month during the months of June through September, the Customer's kW and kWhr Electric Chiller Reduction will be deducted from the allocation of power made under this Rider to determine the Customer's load eligible for the rate reductions specified in section (H); provided, however, that the reduction can never result in a negative allocation.

(D) Scope of BIR Program

A maximum of 452 MW are allocated under this Rider, as follows:

Program Component	Maximum Aggregate MW Allocation
New York City Comprehensive Package	165
Westchester Comprehensive Package	40
New and Vacant Program	95
Biomedical Research	80
Business Incubators & Graduates	12 (10 MW to NYC and 2 MW to Westchester)
EV Quick Charging Station Program	30
COVID -19 BIR	30 (25 MW to SC 2 and 5 MW to SC 9)

As allocations to Customers in a particular program component expire, such allocations will be available for re-use in that program at the then-current Rider terms and rate reductions. When the EV Quick Charging Station Program component or the COVID – 19 BIR component expire, the 30 MW applicable for each BIR component will be reallocated to the New and Vacant Program.

GENERAL RULES
24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE - Continued

(E) Term of BIR Rate Reductions

(1) BIR rate reductions will be available under the New York City or Westchester Comprehensive Package for an initial term of service of no less than three years and no more than five years, and will either terminate after the initial term or be followed by a phase-out period of three to five years, as specified in the contract. If New York City or Westchester County uses the Recharge New York ("RNY") program or the START-UP NY program as a qualifying program under the Comprehensive Package of Economic Incentives, the BIR term shall not extend beyond the period of the Customer's participation in the respective program. At any time, the governmental agency designating the Customer for service under the Comprehensive Package may reduce the load eligible for rate reductions if the agency determines that the Customer is not fulfilling its economic-development commitments.

(2) BIR rate reductions will be available to Business Incubator Graduates for nonrenewable five-year terms, with no phase-out period. BIR rate reductions provided to Business Incubator Graduates will not be transferrable to other premises, unless the Business Incubator Graduate moved to another premises due to reasons outside the recipient's control, including, but not limited to, a fire or other incident that renders the existing space uninhabitable, or a taking of the property by eminent domain. A Business Incubator Graduate who receives service under this Rider will continue to be eligible for service under this Rider for the remainder of its term if the Business Incubator Graduate remains at the same location and: (a) merges with another business, but does not change the name of its business; or (b) changes the name of its business due to incorporation of the business, which was previously a sole proprietorship or partnership. Except as specified above, successor businesses and successor Customers will not be eligible to receive service under this Rider for any months remaining under the predecessor's term of service under this Rider.

(3) BIR rate reductions are available under the EV Quick Charging Station Program until December 31, 2025.

(4) BIR rate reductions will be available to the Biomedical Research Program for ten-year terms, with no phase-out period.

(5) BIR rate reductions will be available under COVID-19 BIR for a term of no more than three years.

(6) BIR rate reductions for all other Customers will be provided for a period of ten years, which is composed of an initial five-year term of service followed by a phase-out period of five years.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE - Continued

(F) Applications for Service

(1) An application for service under this Rider must be made in writing to the Company. Applications made for premises located within 250 feet of a steam main in the Borough of Manhattan must include information about the Customer’s electric and/or hybrid electric chilling equipment, including its nameplate rating and energy efficiency information. Approval of an application will be contingent upon the Customer's receipt of economic development benefits and ability to meet other criteria established under this Rider. Except for COVID-19 BIR applications, which will be accepted through December 31, 2023, applications to commence service under this Rider will be accepted until one day before expiration of the most recent electric rate plan adopted by the Commission, or, if the rate plan’s terms and conditions continue beyond that date, until base rates are reset. Subject to the consent of the Public Service Commission, applications for service prior to the specified dates will not be accepted if the Company determines that the rate reductions provided hereunder are no longer cost justified.

(2) Applications must be made under the New York City or Westchester Comprehensive Package within 30 days of application for a Comprehensive Package of Economic Incentives from state or local authorities. A completed application must include a letter from the governmental economic development agency negotiating the package confirming conveyance of a Comprehensive Package of Economic Development Benefits to the applicant and recommending acceptance for Rider J service.

(3) Applications by Customers requesting service under the New and Vacant Program must include suitable documentation that the Customer received a Substantial Real Property Tax Incentive or ECSP energy rebates. Applications by Customers requesting service under the Biomedical Research Program must include a showing of expected economic development benefits, including new jobs, over the long term as a result of Rider J service to the space used for Biomedical Research and associated administrative space within such buildings and a showing that National Institute of Health grants will not contribute towards the cost of electric service covered by this Rider.

(4) A Business Incubator may apply for service under this Rider at any time. Such Business Incubator must provide: (a) documented proof of funding or other support from New York City, Westchester County, other government entity, or another entity whose mission includes development of businesses in New York City or Westchester County; (b) a certificate of incorporation or formation or its equivalent; and (c) an analysis of the amount of electricity needed.

(5) A Business Incubator Graduate must apply for service under this Rider within 60 days of leaving the Business Incubator and signing a deed or lease for commercial or research space, and it must provide: (a) proof of “graduation” from the Business Incubator; (b) a certificate of incorporation or formation or its equivalent; (c) a copy of the signed lease or deed for the business location; and (d) an analysis of the amount of electricity needed.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE – Continued

(F) Applications for Service - Continued

(6) Applications must be made under the EV Quick Charging Station Program with proof of an EV station building permit and proof of payment of excess distribution facilities, if applicable. A completed application must include proof of eligibility that the station is publicly accessible.

(7) Applications must be made under COVID-19 BIR with proof of receiving financial assistance such as loan and grant programs sponsored by city, county, state, or federal government agencies that are directly related to COVID-19.

(G) Restrictions as to the Availability of the Rider

Service under this Rider shall not be available as follows:

(1) to Customers receiving service under Special Provision H of SC 9 or Rider Y;
(2) where service is furnished solely or predominantly for telephone booths, warning lights, bus stop shelters, signboards, cable television and telecommunication local distribution facilities, or similar structures or locations;
(3) to a building or premises where 25 percent or more of the square footage of the premises is used on a permanent basis for residential purposes, unless (i) the residential space is separately metered or (ii) the Customer receives high-tension service and applies for Rider J as a Biomedical Research Customer, Business Incubator, or Business Incubator Graduate and the load designated for service under this Rider excludes any of the residential load on the premises;
(4) for public light and power in multi-tenanted residential buildings, or for construction purposes, or for activities of a temporary nature as described in General Rule 5.2.7;
(5) to residential-type premises where the account is in the name of a non-residential entity, such as apartments for renting purposes;
(6) to any Customer eligible for service under SC 1, such as a corporation or association organized and conducted in good faith for religious purposes; or
(7) to retail establishments (except for participants in the EV Quick Charging Station Program and COVID-19 BIR), i.e., entities that are engaged in the sale of goods or services to end-users, including, without limitation, restaurants; hotels; entertainment-related establishments (unless primarily used for film production); and museums; or
(8) to energy intensive facilities that generate relatively few new jobs, such as web-hosting centers, data centers and data switching facilities, except for participants in the EV Quick Charging Station Program. This subsection shall not restrict the availability of this Rider to energy intensive facilities where such facilities are part of a larger facility used in the ordinary course of business, such as corporate computer centers. Governmental economic development agencies shall have the discretion to allocate power available under this Rider to energy intensive facilities based upon factors other than the amount of anticipated electric demand, provided that a compelling reason to do so can be shown.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER J - BUSINESS INCENTIVE RATE - Continued

(H) Rate Reductions

(1) The applicable rate reduction percentage is based on the date the Customer commenced BIR service, as shown below:

Rate Class	BIR Commencement Date			
	4/1/2001-2/28/2014	3/1/2014 - 1/31/2017	2/1/2017 - 12/31/2022	1/1/2023 and after
SC 9 – Rate I, III or IV	40.56%	49%	39%	39%
SC 9 – Rate II or V	32.08%	45%	34%	34%
SC 2 (COVID-19 BIR only)	N/A	N/A	N/A	39%

The rate reduction percentage under SC 9 will be applied to monthly Demand Delivery Charges and monthly Energy Delivery Charges under Rate I, Rate II, and Rate III, and to the Customer Charge, Contract Demand Delivery Charge, and As-used Daily Demand Delivery Charges under Rate IV and Rate V, as applicable, before application of the Increase in Rates and Charges (described in General Rule 30). The rate reduction percentage under SC 2 will be applied to the Customer Charge and monthly Energy Delivery Charges under Rate I and Rate II, and to the Customer Charge and Billable Demand Charge under Rider AA, before application of the Increase in Rates and Charges (described in General Rule 30). No rate reductions will be applied to other delivery charges, including but not limited to the Billing and Payment Processing Charge, and other delivery charges and adjustments specified in General Rule 26. The Revenue Decoupling Mechanism is not applicable to Customers served under Rider J.

(2) Where the Customer is subject to a phase-out of BIR rate reductions after the initial term of service under this Rider, the rate reduction percentage will be reduced in equal decrements each year, so that the rate reduction is phased-out completely at the end of the final year of Rider J service. For example, during a five-year phase-out period, the rate reduction percentage will be reduced by one-sixth each phase-out year.

(3) The stated rate reductions will apply to entire load of the Customer designated for service under this Rider, except for the following: (a) Customers for whom the government agency designates a lesser load; (b) Customers who are subject to the Electric Chiller Reduction for the months of June through September; (c) Business Incubators for load in excess of 750 kW; and (d) Business Incubator Graduates for load in excess of 500 kW. For Customers served under Grandfathered Net Metering or Phase One Net Metering under Rider R, the reduction applicable to energy delivery charges will apply only to the net kilowatthours delivered by the Company. For Customers served under the Value Stack Tariff under Rider R, the reduction applicable to energy delivery charges will apply to the net hourly consumption.

(4) Service under this Rider will terminate to any Customer under COVID-19 BIR who has received rate reductions totaling $50,000 over the Customer's BIR term (i.e., up to a maximum of three years).

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER L - DIRECT LOAD CONTROL PROGRAM - Continued

G. Restrictions

A participant may not enroll a Control Device in both Rider L and any other Company or NYISO demand-response program (e.g., the NYISO Special Case Resources Program, the Company's Rider T program, or the Company's Rider AC program).

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER P

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT

Applicable to SCs 5, 8, 9, 11, 12, and 13
(Subject to the provisions thereof)

A. Applicability

Under this Rider, Customers must make a one-time election to participate under one or more of the following options: Option A - Customer Chooses Contract Demand, Option B – Locational Variant Daily As-used Demand Pricing, and Option C – Export Pilot Credit. Options A and B are available to any new or existing Standby Service Customer taking service under SCs 5, 8, 9, 12, or 13 or PASNY, including Customers taking service under General Rule 20.4.5 and General Rule 20.4.6, except for Customers taking service under Station Use by Wholesale Generators. Option C is available to new or existing Customers taking service under SC 11 and taking service under another Service Classification through the same service connection.

B. Eligibility

This Rider is available for up to a total of 125 MW, with MWs measured by the distributed generator's nameplate rating capacity or inverter capability, as follows: (1) 75 MW is reserved for customers that have qualified under General Rule 20.3.3; and (2) 50 MW is available to standby customers, either new or existing, that do not qualify under General Rule 20.3.3. If the Customer or the Company terminates the Customer's service under this Rider, the program size will be reduced by the associated MWs and those MWs will not be available for re-use by any Customers.

C. Application and Term of Service

A Customer applying for service under this Rider must submit a completed "Application for Net Metering or Standby Service and/or Buy-Back Service" set forth in Application Form G in the General Rules. Applications to participate under this Rider will be considered until the Pilot is fully subscribed, or if received by December 31, 2021, whichever is sooner. The term of service under this Rider is ten years from the date the Customer commences taking service under this Rider or until this Rider expires, whichever is sooner. If a Customer makes a one-time election to terminate its service under this Rider, the Customer will revert back to its otherwise applicable rate. If there is no prior rate, the Customer will be subject to its otherwise applicable rate.

This Rider expires on January 1, 2032.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

D. Metering

Customers under this Rider must also comply with the following metering requirements.

The output of the generating facility and/or the charging usage and discharge output of the Electric Energy Storage facility, as applicable, must be separately metered using an Output Meter (as defined in General Rule 2) that the Customer arranges to be furnished and installed at Customer expense.

Customers participating under this Rider are required to have Interval Metering with communications capability. If Interval Metering is not required for billing under the Customer's Service Classification or if Interval Metering cannot be provided through the Company's deployment of AMI meters, the Customer shall be responsible for the installation of the meter upgrade at the cost described in General Rule 17.6 and shall provide and maintain the communications service pursuant to General Rule 6.5.

E. Applicable Networks and Time Periods

The rates and applicable time periods under Option B and the measurement hours under Option C will vary based on the Customer's location and are based on event call windows for the Company's Commercial System Relief Program ("CSRP"). A separate set of rates under Option B is available for Customers in a CSRP network who are also in a Distribution Load Relief Program ("DLRP") Tier 2 network. The CSRP event call windows and DLRP Tier 2 networks will be available on the Company's website.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing

All rates and charges are applicable to the Service Classification of the Customer, with the replacement of the following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period. Customers under this option will also receive shadow billing, for informational purposes, at the applicable Standby Service rates.

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks, except for Customers in a DLRP Tier 2 network

SC 5	Rate III Low Tension Service	Rate III High Tension Service	Rate IV Low Tension Service	Rate IV High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$0.5479	$0.3973	$0.6523	$0.5131
Monday through Friday, 8 AM to 10 PM	$0.6380	$0.1925	$0.7338	$0.2279
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$0.5439	$0.3944	$0.6477	$0.5094
Monday through Friday, 8 AM to 10 PM	$0.6380	$0.1925	$0.7338	$0.2279
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$0.5518	$0.4002	$0.6571	$0.5168
Monday through Friday, 8 AM to 10 PM	$0.6380	$0.1925	$0.7338	$0.2279
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$0.5237	$0.3798	$0.6236	$0.4904
Monday through Friday, 10 AM to 12 AM	$0.6380	$0.1925	$0.7338	$0.2279
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks, except for Customers in a DLRP Tier 2 network - Continued

SC 8	Rate IV Low Tension Service	Rate IV High Tension Service	Rate V Low Tension Service	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.4487	$1.0896	$1.3705	$1.0377
Monday through Friday, 8 AM to 10 PM	$1.4208	$0.4507	$1.3777	$0.4376
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.4435	$1.0857	$1.3647	$1.0333
Monday through Friday, 8 AM to 10 PM	$1.4208	$0.4507	$1.3777	$0.4376
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.4338	$1.0783	$1.3612	$1.0306
Monday through Friday, 8 AM to 10 PM	$1.4208	$0.4507	$1.3777	$0.4376
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.4214	$1.0690	$1.3567	$1.0272
Monday through Friday, 10 AM to 12 AM	$1.4208	$0.4507	$1.3777	$0.4376
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks, except for Customers in a DLRP Tier 2 network - Continued

SC 9	Rate IV Low Tension Service	Rate IV High Tension Service	Rate V Low Tension Service	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.0197	$0.7852	$1.0298	$0.8178
Monday through Friday, 8 AM to 10 PM	$1.0101	$0.3163	$1.0500	$0.3415
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.0220	$0.7869	$1.0313	$0.8190
Monday through Friday, 8 AM to 10 PM	$1.0101	$0.3163	$1.0500	$0.3415
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.0308	$0.7938	$1.0347	$0.8216
Monday through Friday, 8 AM to 10 PM	$1.0101	$0.3163	$1.0500	$0.3415
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.0560	$0.8131	$1.0571	$0.8394
Monday through Friday, 10 AM to 12 AM	$1.0101	$0.3163	$1.0500	$0.3415
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks, except for Customers in a DLRP Tier 2 network - Continued

SC 12	Rate IV Low Tension Service	Rate IV High Tension Service	Rate V Low Tension Service	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.1704	$0.8393	$1.2179	$0.8463
Monday through Friday, 8 AM to 10 PM	$1.4058	$0.4820	$1.5515	$0.5329
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.1572	$0.8299	$1.2214	$0.8488
Monday through Friday, 8 AM to 10 PM	$1.4058	$0.4820	$1.5515	$0.5329
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.1493	$0.8242	$1.2153	$0.8445
Monday through Friday, 8 AM to 10 PM	$1.4058	$0.4820	$1.5515	$0.5329
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.1510	$0.8255	$1.2146	$0.8440
Monday through Friday, 10 AM to 12 AM	$1.4058	$0.4820	$1.5515	$0.5329
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks, except for Customers in a DLRP Tier 2 network - Continued

SC 13	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 11 AM to 3 PM	$0.9591
Monday through Friday, 8 AM to 10 PM	$0.2836
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515
CSRP Network 2 PM to 6 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 2 PM to 6 PM	$0.8464
Monday through Friday, 8 AM to 10 PM	$0.2836
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515
CSRP Network 4 PM to 8 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 4 PM to 8 PM	$0.6656
Monday through Friday, 8 AM to 10 PM	$0.2836
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515
CSRP Network 7 PM to 11 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 7 PM to 11 PM	$0.5872
Monday through Friday, 10 AM to 12 AM	$0.2633
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks, except for Customers in a DLRP Tier 2 network - Continued

PASNY	Rate III Low Tension Service	Rate III High Tension Service	Rate IV Low Tension Service	Rate IV High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.2784	$0.9473	$0.9995	$0.7584
Monday through Friday, 8 AM to 10 PM	$1.3903	$0.4472	$1.1698	$0.3775
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.2886	$0.9549	$1.0008	$0.7595
Monday through Friday, 8 AM to 10 PM	$1.3903	$0.4472	$1.1698	$0.3775
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.3223	$0.9799	$1.0006	$0.7592
Monday through Friday, 8 AM to 10 PM	$1.3903	$0.4472	$1.1698	$0.3775
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.3621	$1.0094	$1.0027	$0.7608
Monday through Friday, 10 AM to 12 AM	$1.3903	$0.4472	$1.1698	$0.3775
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks who are also in a DLRP Tier 2 network

SC 5	Rate III Low Tension Service	Rate III High Tension Service	Rate IV Low Tension Service	Rate IV High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$0.6341	$0.4234	$0.7505	$0.5441
Monday through Friday, 8 AM to 10 PM	$0.5529	$0.1669	$0.6360	$0.1975
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$0.6295	$0.4202	$0.7452	$0.5402
Monday through Friday, 8 AM to 10 PM	$0.5529	$0.1669	$0.6360	$0.1975
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$0.6387	$0.4264	$0.7560	$0.5481
Monday through Friday, 8 AM to 10 PM	$0.5529	$0.1669	$0.6360	$0.1975
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$0.6061	$0.4046	$0.7175	$0.5201
Monday through Friday, 10 AM to 12 AM	$0.5529	$0.1669	$0.6360	$0.1975
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.6695	$0.3675	$0.8877	$0.5295

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks who are also in a DLRP Tier 2 network - Continued

SC 8	Rate IV Low Tension Service	Rate IV High Tension Service	Rate V Low Tension Service	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.6591	$1.1563	$1.5657	$1.0996
Monday through Friday, 8 AM to 10 PM	$1.2314	$0.3906	$1.1940	$0.3793
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.6532	$1.1522	$1.5590	$1.0950
Monday through Friday, 8 AM to 10 PM	$1.2314	$0.3906	$1.1940	$0.3793
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.6421	$1.1444	$1.5550	$1.0922
Monday through Friday, 8 AM to 10 PM	$1.2314	$0.3906	$1.1940	$0.3793
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.6279	$1.1345	$1.5498	$1.0885
Monday through Friday, 10 AM to 12 AM	$1.2314	$0.3906	$1.1940	$0.3793
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.3640	$0.8155	$1.3108	$0.7828

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks who are also in a DLRP Tier 2 network - Continued

SC 9	Rate IV Low Tension Service	Rate IV High Tension Service	Rate V Low Tension Service	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.1578	$0.8284	$1.1703	$0.8639
Monday through Friday, 8 AM to 10 PM	$0.8754	$0.2741	$0.9100	$0.2960
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.1604	$0.8303	$1.1720	$0.8651
Monday through Friday, 8 AM to 10 PM	$0.8754	$0.2741	$0.9100	$0.2960
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.1703	$0.8375	$1.1758	$0.8679
Monday through Friday, 8 AM to 10 PM	$0.8754	$0.2741	$0.9100	$0.2960
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.1990	$0.8579	$1.2013	$0.8867
Monday through Friday, 10 AM to 12 AM	$0.8754	$0.2741	$0.9100	$0.2960
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$0.9860	$0.5823	$1.0551	$0.6476

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks who are also in a DLRP Tier 2 network - Continued

SC 12	Rate IV Low Tension Service	Rate IV High Tension Service	Rate V Low Tension Service	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.3719	$0.9084	$1.4443	$0.9241
Monday through Friday, 8 AM to 10 PM	$1.2184	$0.4178	$1.3447	$0.4619
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.3564	$0.8982	$1.4485	$0.9268
Monday through Friday, 8 AM to 10 PM	$1.2184	$0.4178	$1.3447	$0.4619
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.3471	$0.8921	$1.4412	$0.9221
Monday through Friday, 8 AM to 10 PM	$1.2184	$0.4178	$1.3447	$0.4619
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.3492	$0.8934	$1.4404	$0.9216
Monday through Friday, 10 AM to 12 AM	$1.2184	$0.4178	$1.3447	$0.4619
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2843	$0.6069	$1.5044	$0.6842

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks who are also in a DLRP Tier 2 network - Continued

SC 13	Rate V High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 11 AM to 3 PM	$1.0393
Monday through Friday, 8 AM to 10 PM	$0.2458
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515
CSRP Network 2 PM to 6 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 2 PM to 6 PM	$0.9172
Monday through Friday, 8 AM to 10 PM	$0.2458
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515
CSRP Network 4 PM to 8 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 4 PM to 8 PM	$0.7213
Monday through Friday, 8 AM to 10 PM	$0.2458
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515
CSRP Network 7 PM to 11 PM	
Charges applicable for the months of June, July, August, and September	
Monday through Friday, 7 PM to 11 PM	$0.6364
Monday through Friday, 10 AM to 12 AM	$0.2282
Charge applicable for all other months	
Monday through Friday, 8 AM to 10 PM	$0.4515

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Q –STANDBY RATE PILOT - Continued

G. Option B - Locational Variant Daily As-used Demand Pricing - Continued

The following As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand, are applicable to Customers in the specified CSRP networks who are also in a DLRP Tier 2 network - Continued

PASNY	Rate III Low Tension Service	Rate III High Tension Service	Rate IV Low Tension Service	Rate IV High Tension Service below 138 kV
CSRP Network 11 AM to 3 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 11 AM to 3 PM	$1.4788	$1.0118	$1.1583	$0.8105
Monday through Friday, 8 AM to 10 PM	$1.2050	$0.3876	$1.0138	$0.3271
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641
CSRP Network 2 PM to 6 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 2 PM to 6 PM	$1.4906	$1.0199	$1.1599	$0.8117
Monday through Friday, 8 AM to 10 PM	$1.2050	$0.3876	$1.0138	$0.3271
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641
CSRP Network 4 PM to 8 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 4 PM to 8 PM	$1.5296	$1.0465	$1.1597	$0.8114
Monday through Friday, 8 AM to 10 PM	$1.2050	$0.3876	$1.0138	$0.3271
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641
CSRP Network 7 PM to 11 PM				
Charges applicable for the months of June, July, August, and September				
Monday through Friday, 7 PM to 11 PM	$1.5756	$1.0780	$1.1620	$0.8131
Monday through Friday, 10 AM to 12 AM	$1.2050	$0.3876	$1.0138	$0.3271
Charge applicable for all other months				
Monday through Friday, 8 AM to 10 PM	$1.2251	$0.7709	$0.8486	$0.5641

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

G. Charges and Credits – Grandfathered Net Metering and Phase One NEM – Continued

3. Annual Reconciliation - Continued

c. The Company will carry forward the credit to all other Customers, as described below:

If the Customer does not participate in Remote Net Metering, any excess net energy kWhr credits shall be carried forward to the next year on the Customer's account. If the Customer participates in Remote Net Metering, any credit remaining on the RNM Host Account after all of its Satellite Accounts have been credited (as described in section G.2.c. of this Rider) shall be carried forward to the next year on the RNM Host Account.

4. Account Closure

The Company requires an actual reading to close a Rider R account. The Company will close an account on the earlier of: (a) the first cycle date on which a reading is taken following the requested turn off date, (b) the date of a special reading, which a Customer may request at the charge specified in General Rule 17.1, or (c) the date of request for Customers with communicating AMI meters. After a CDG Satellite is removed from a monthly allocation by its CDG Host, pursuant to section F.2.c of this Rider, or its final bill is rendered on a net-metered Customer's account, including the account of an RNM or CDG Host, any remaining kWhr credit will not be cashed out or transferred, except as provided below. Any remaining CDG Host Banked Credit will not be refunded or transferred. RNM and CDG Satellite Account(s) shall no longer receive credits after the final bill is rendered on the account of its RNM or CDG Host.

a. CDG Satellite Account Closure

When a CDG Satellite Account is closed and a credit remains on a CDG Satellite Account after its final bill is rendered, such credit will be returned to the CDG Host Account.

When a CDG Satellite Account terminates its subscription with a CDG Host, any remaining banked credits on a CDG Satellite Account will be transferred to the CDG Host Banked Credit. The Company will transfer any banked credits on the CDG Satellite Account to the CDG Host Banked Credit when the CDG Satellite Account is no longer included on the CDG Host's allocation.

A CDG Satellite Account that has been removed from a CDG Host project but continues to maintain an active utility account may not subscribe to a new CDG Host or CDG Net Crediting project until the billing period after which all Satellite banked credits are returned to the original CDG Host Banked Credit.

Any remaining kWhr or monetary credits described in Sections G.2.c.(v) or G.2.c.(vi) of this Rider, as applicable, will be transferred to the CDG Host Banked Credit after the CDG Satellite's final bill is rendered.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER R - Net Metering and Value Stack Tariff for Customer-Generators - Continued

I. Charges and Credits – Customer Benefit Contribution ("CBC") Charge

Phase One NEM Customers described in paragraph 3. of the Phase One NEM Applicability Section of this Rider with electric generating equipment that interconnects on or after January 1, 2022, who either remain on Phase One NEM or receive compensation under the Value Stack Tariff will be subject to a CBC Charge for the Customer's term of service specified in Section K. The amount a customer is billed for the CBC will be determined each billing period by multiplying the CBC Charge by the nameplate capacity rating in kW DC of the customer's electric generating equipment.

For Customers with more than one electric generating technology for which the CBC is applicable, the CBC Charge will be assessed separately based on the nameplate capacity rating of each technology; however, where one of the multiple electric generating technologies is an Electric Energy Storage system, the CBC shall be assessed solely on the nameplate rating(s) of the other electric generating technology or technologies.

The CBC Charge cannot be offset by any credit described in Sections G and H of this Rider.

The CBC rates will be set forth on the Statement of Customer Benefit Contribution. This Statement will be filed with the Commission at least 15 days before January 1 of each year.

J. Restrictions

Service under this Rider shall not be available to a Customer taking service under:

(a) SC 9 – Special Provision H; or
(b) the PASNY Rate Schedule, except PASNY CDG Satellites of CDG Hosts taking service under this Rate Schedule.

With the exception of the Customer-generators specified in Section A.9 of this Rider and Rate Choice Customers as described in General Rule 20, all other Customers served under this Rider shall be exempt from General Rule 20.

Customers served under Section A.9 of this Rider are ineligible to take service under Option C of Rider Q.

Customers served under Grandfather Net Metering and Phase One NEM of this Rider are ineligible to participate in Rider AC.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER T – COMMERCIAL DEMAND RESPONSE PROGRAMS

Applicable to SCs 1, 2, 5, 8, 9, 11, 12, and 13
(Subject to the provisions thereof)

A. Applicability

To any Customer taking service under one of the above SCs, to any PASNY Customer, and to any Aggregator that contracts to provide Load Relief of at least 50 kW during the Capability Period and meets the requirements of this Rider. Service under this Rider is not available to participants in Rider L. Service under this Rider is also not available to Customers who are otherwise contractually precluded from taking service under this Rider, either by their own contract or because they are represented by a third party that is contractually precluded.

B. Definitions

1. Programs

Commercial System Relief Program (“CSRP”) is generally activated for the following conditions: (a) for Network peak shaving when the day-ahead system electric load forecast is 92 percent or greater of forecasted system peak; (b) when the day-ahead temperature variable is forecasted to exceed 84 degrees with an option to limit activation to particular New York City boroughs or the County of Westchester within the Company’s service territory; or (c) in limited situations when a DLRP event is called in a specific Network.

Distribution Load Relief Program (“DLRP”) is a contingency program activated by Con Edison to prevent or mitigate critical situations on the utility’s electric grid, typically called on a Network basis.

2. Definitions applicable to both CSRP and DLRP

"Aggregation” means either a Sub-aggregation or all Customers represented by an Aggregator within a Network if there are no Sub-aggregations for that Aggregator within that Network.

"Aggregator" refers to a party other than the Company that represents and aggregates the load of Customers who collectively have a Load Relief potential of 50 kW or greater under CSRP or DLRP and that is responsible for the actions of the Customers it represents, including performance and, as applicable, repayments to the Company.

“Capability Period” under this Rider refers to the period from May 1 through September 30.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER T – COMMERCIAL DEMAND RESPONSE PROGRAMS - Continued

B. Definitions – Continued

2. Definitions applicable to both CSRP and DLRP - Continued

"Network" refers to a distribution network or load area designated by the Company.

"Sub-aggregation" means a subset of Customers represented by an Aggregator within a Network. An Aggregator may have up to three Sub-aggregations per Network as long as each Sub-aggregation contains Customers who collectively have a Load Relief potential of 50kW or greater in the Network.

"Test Event" refers to the Company's request under the Reservation Payment Option of either CSRP or DLRP for Direct Participants and Aggregators to provide Load Relief in order to test participants' response to a request for Load Relief. The duration of a Test Event is one hour for CSRP and up to two hours for DLRP. If a Test Event is called under CSRP, Load Relief will be requested within the four-hour span of Contracted Hours for the Network. If called under DLRP, Load Relief will be requested at a time determined solely at the Company's discretion but not between the hours of 12:00 AM and 6:00 AM.

3. Definitions applicable to CSRP only

"Advisory" refers to the Company's notice to participants when a condition as defined under General Rule 24.B.1.(a) or (b) has been met. Day-ahead and summer peak forecast information for the system, as well as information on the day-ahead temperature variable forecasts, will be posted to the Company's website.

"Contracted Hours" refers to the four-hour period within a weekday, Monday through Friday during the Capability Period, excluding federal holidays, during which the Direct Participant or Aggregator contracts to provide Load Relief in a Network whenever the Company designates a Planned Event. The Contracted Hours are established by the Company for each Network based on individual Network needs and will be posted on the Company's website no later than January 1 for the upcoming Capability Period. The Contracted Hours for any SC 11 Customer who exports power to the Company shall be the Contracted Hours established by the Company for the Network unless the Company assigns an alternate four-hour period. If the Company assigns an alternate four-hour period, it will notify the Direct Participant or Aggregator within ten calendar days of receiving the application for service under this Rider.

"Planned Event" refers to the Company's request, on not less than two hours' advance notice, for Load Relief during the Contracted Hours. Planned Events will be called if an Advisory, based on the day-ahead forecasted load level, was issued at least 21 hours in advance and the Company's same-day forecasted load level, as updated throughout the day, is at least 92 percent of the forecasted summer system-wide peak. Planned Events may be called if an Advisory, based on the day-ahead forecasted temperature variable, was issued at least 21 hours in advance and the Company's same-day forecasted load level or same-day forecasted temperature variable, as updated throughout the day, is at least 92 percent of the forecasted summer system-wide peak or the temperature variable is expected to exceed 84 degrees, respectively.

"Renewable Generation" means behind-the-meter electric generating equipment that is not fossil-fueled and has no emissions associated with it.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER T – COMMERCIAL DEMAND RESPONSE PROGRAMS - Continued

D. Applications and Term of Service

1. Applications for service by Direct Participants or Aggregators for the Reservation Payment Option or Voluntary Participation Option of either CSRP or DLRP must be made electronically. The desired commencement date must be specified in the application.

   The Company will accept completed applications for the Reservation Payment Option of CSRP or DLRP by April 1 for a May 1 commencement date, and by May 1 for a June 1 commencement date, Where the first day of the month falls on a weekend or federal holiday, applications will be accepted until the first business day after. For the 2021 Capability Period only, the Company will allow revisions to the kW of contracted Load Relief of previously enrolled customers up until June 1, 2021. In cases where these revisions result in a lower kW of contracted Load Relief, the new kW of contracted Load Relief will apply for Event Performance Factor and Reservation Payment calculation purposes for the entire Capability Period. Otherwise, the new kW of contracted Load Relief will be applied beginning the next month.

   If the Company does not bill the participant monthly using Interval Metering at the time of application for CSRP or DLRP, participation in the Reservation Payment Option will not commence unless Interval Metering is operational. If the Company receives a completed CSRP or DLRP application by April 1, service can commence on May 1 if Interval Metering is installed by April 1. If the Company receives a completed CSRP or DLRP application by May 1, service can commence on June 1 if Interval Metering is installed by May 2. If the CSRP or DLRP application is received by May 1, but the above deadline for installation of Interval Metering is not met, service will commence on July 1, provided the Interval Metering is installed by June 1. (Metering and communications requirements are described in section F.)

   The Company will accept applications for participation in the Voluntary Participation Option of CSRP or DLRP at any time provided the metering and communications requirements specified in section F are met.

2. Each application must state the kW of Load Relief that will be provided by the Direct Participant or by the Aggregator for the Network(s) during: (a) the Contracted Hours required for the Network under CSRP or (b) the Load Relief Period, for weekdays and weekends separately, under DLRP. Under DLRP, the stated kW of Load Relief for weekends must be equal to or greater than 25 percent of the stated kW of Load Relief for weekdays. In addition, weekend days shall include Memorial Day, Independence Day, and Labor Day, under DLRP.

3. Load Relief of an Aggregator will be measured on a portfolio basis by Aggregation.

4. A single CBL Verification Methodology will be used for each Customer account to assess both energy (kWh) and demand (kW) Load Relief.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER T – COMMERCIAL DEMAND RESPONSE PROGRAMS - Continued

D. Applications and Term of Service - Continued

5. A Direct Participant or Aggregator may change the CBL Verification Methodology or kW of pledged Load Relief for the upcoming Capability Period provided the request is received prior to commencing participation for that Capability Period.

   An Aggregator may increase its kW of pledged Load Relief in a Network during a Capability Period only if it enrolls Customers whose Aggregator either exits the program or is suspended from enrollment in the program for noncompliance with Aggregator eligibility requirements or the Company's operating procedures. In such case, the Aggregator may increase its kW of pledged Load Relief up to the amount of the transferred Customers' existing kW of pledged Load Relief.

6. Except for Renewable Generation, Electric Generating Equipment is prohibited from operating under CSRP within one-half mile of a peaking generator located at Gowanus (Brooklyn), Narrows (Brooklyn), Hudson Avenue (Brooklyn), Astoria (Queens), 59th Street (Manhattan, West Side) and 74th Street (Manhattan, East Side), all as shown on the Company's website.

   In other geographic areas, participation by diesel-fired Electric Generating Equipment will be permitted under CSRP only if the engine for the equipment is model year 2000 or newer or written certification by a professional engineer is attached to the CSRP application attesting that the NOx emission level is no more than 2.96 lb/MWh. Participation by such diesel-fired Electric Generating Equipment will be limited to 20 percent of the total kW enrolled under CSRP for the Capability Period. Enrollment by such generators will be accepted on a first come, first served basis. Within these geographic areas, no limit or cap will be placed under CSRP on the following: natural gas-fired rich burn Electric Generating Equipment that incorporates three-way catalyst emission controls; natural gas lean-burn Electric Generating Equipment with an engine of model year vintage 2000 or newer; or Electric Generating Equipment that has a NOx emissions level of no more than 2.96 lb/MWh.

   Electric Generating Equipment operating under DLRP is not subject to the above limitations.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER T – COMMERCIAL DEMAND RESPONSE PROGRAMS - Continued

D. Applications and Term of Service - Continued

7. If a Direct Participant or Aggregator requests to operate Electric Generating Equipment for Load Relief purposes under either CSRP or DLRP, the application must state generator information, including the unit's nameplate rating, manufacturer, date of manufacture, fuel type or energy source, and the kW enrolled using this equipment.

   If applying for service under this Rider, the application must also identify whether the unit incorporates three-way catalyst emission controls (natural gas-fired rich burn), a natural gas lean-burn engine of model year vintage 2000 or newer, or a diesel-fired engine of model year vintage 2000 or newer, or whether it has a NOx emission level of no more than 2.96 lb/MWh. If the generating equipment has a NOx emission level of no more than 2.96 lb/MWh, but is not natural gas-fired rich burn generating equipment that incorporates three-way catalyst emission controls, a natural gas lean-burn engine of model year vintage 2000 or newer, or a diesel-fired engine of model year vintage 2000 or newer, written certification by a professional engineer must be attached to the application attesting to the accuracy of all generation-related information contained in the application, including the NOx emission level. Furthermore, participants enrolled in a NYISO market-based program offered by the Company, NYPA or other entity, such as the Day-ahead Demand Response Program or the Demand-Side Ancillary Service Program, must provide the Company with their NYISO generator identification number, under a confidentiality agreement, and give the Company the ability to view their market participation activity. This information will be used to verify the times of participation in these other programs to prevent double-payment during concurrent events.

   A copy of the required New York State Department of Environmental Conservation ("DEC") permit or registration must be included either with the application or within seven days of applying. If the permit or registration has not yet been issued, a copy of application to the DEC for the required permit or registration may instead be submitted; provided, however, that a copy of the actual DEC permit or registration must be submitted before commencing service. By applying for service, Direct Participants and Aggregators (on behalf of their customers) agree to permit the Company to provide information regarding the Electric Generating Equipment to the DEC for its review, subject to the DEC's agreement to keep this information confidential.

8. Rider R Value Stack Tariff Customers that enroll in Rider T are ineligible to receive DRV and LSRV compensation. This is a one-time, irreversible decision that can be made at any point during a project's Value Stack compensation term.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER T – COMMERCIAL DEMAND RESPONSE PROGRAMS - Continued

J. Restrictions on Performance Payments

Performance Payments will not be made under DLRP for Customer accounts participating in CSRP during concurrent Load Relief Hours.

Performance Payments will not be made under CSRP or DLRP if the Direct Participant or Aggregator (on behalf of its customer) receives payment for energy under other demand response program (e.g., NYISO's Day-ahead Demand Reduction Program or NYISO's Special Case Resources Program) in which the customer is enrolled through the Company during concurrent Load Relief hours in the same Network(s).

If an SC 11 Customer participates in the NYISO market through Con Edison and receives payment for energy during concurrent Load Relief hours, Performance Payments will be made under CSRP or DLRP only for Load Relief in excess of the Customer's CBL, expressed in kWh.

Performance Payments will not be made under CSRP or DLRP if service is taken under Rider R.

Performance Payments will not be made under the Term-DLM program of Rider AC for Customer accounts participating in DLRP during concurrent Load Relief Hours.

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER V

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

RIDER W
[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Y - RATES AND CHARGES FOR CUSTOMERS REQUESTING HIGH LOAD-DENSITY SERVICE - Continued

B. Definitions: The following definitions apply for purposes of this Rider:

1. “Contract Demand”

   a. “Contract Demand” means, except for Customers served under one or more of the economic development programs described in General Rule 11 (“Economic Development Programs”), the higher of (i) the contract demand specified in the Service Agreement for service under this Rider, or (ii) the highest registered demand on the Customer’s account.

   b. “Contract Demand” under each Economic Development Program means the Customer’s demand allocation under that program, as applicable. “Contract Demand under Economic Development Programs” means the sum of the Customer’s demand allocations under the various applicable programs.

   c. “Service Classification Component of the Contract Demand,” applicable to Customers who take service under one or more Economic Development Programs, means the higher of (i) the Contract Demand specified in the Rider Y Service Agreement minus the Contract Demand under Economic Development Programs or (ii) the highest registered demand on the Customer’s account minus the Contract Demand under Economic Development Programs.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Z – SC 1 INNOVATIVE PRICING PILOT - Continued

G. Delivery Charges

Customers will be assigned to one of the following rates by the Company.

Rate I – 12 Noon to 8 PM Summer and Non-Summer On-Peak

Customer Charge — $20.00 per month

Billable Demand Charge

Charges applicable for the months of June, July, August, and September

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$28.44 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Charges applicable for all other months

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$21.86 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

Rate II – 12 Noon to 8 PM Summer On-Peak and All-Hours Non-Summer

Customer Charge — $20.00 per month

Billable Demand Charge

Charges applicable for the months of June, July, August, and September

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$28.44 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Charges applicable for all other months

All-Hours	$26.76 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Z – SC 1 INNOVATIVE PRICING PILOT - Continued

G. Delivery Charges - Continued

Rate III – 2 PM to 10 PM Summer and Non-Summer On-Peak

Customer Charge $20.00 per month

Billable Demand Charge

Charges applicable for the months of June, July, August, and September

On-Peak: Weekdays, excluding holidays, 2 PM to 10 PM	$28.44 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Charges applicable for all other months

On-Peak: Weekdays, excluding holidays, 2 PM to 10 PM	$21.86 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

Rate IV – 12 Noon to 8 PM Summer and Non-Summer On-Peak with Time-of-Use Supply

Customer Charge $20.00 per month

Billable Demand Charge

Charges applicable for the months of June, July, August, and September

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$28.44 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Charges applicable for all other months

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$21.86 per kW
Off-Peak: All other hours of the week	$9.58 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

If a customer taking service under Rate IV elects to switch to Retail Access Service, such customer will be transferred to Rate I unless the Customer chooses to leave the Pilot.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Z – SC 1 INNOVATIVE PRICING PILOT - Continued

G. Delivery Charges - Continued

Rate V – Demand Subscription

Customer Charge	$20.00 per month
Subscribed Demand Charge	
Charges applicable for all months	
Subscribed Demand	$28.36 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

Rate VI – Demand Subscription with Summer Overages

During the months of June through September, in addition to the Subscribed Demand Charge, Customers will be subject to Overage Demand Charges for demands occurring on non-holiday weekdays between the hours of 12 Noon and 8 PM in excess of the subscribed levels. The Overage Demand Charge shall be assessed on the kW amount by which the average of the highest three maximum daily demands during the aforementioned hours in the billing cycle exceeds the Subscribed Demand.

Customer Charge	$20.00 per month
Subscribed and Overage Demand Charges	
Charges applicable for the months of June, July, August, and September	
Subscribed Demand	$26.95 per kW
Overage Demand	$35.65 per kW
Charges applicable for all other months	
Subscribed Demand	$26.95 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER Z – SC 1 INNOVATIVE PRICING PILOT - Continued

G. Delivery Charges - Continued

Rate VII – 12 Noon to 8 PM Summer and Non-Summer On-Peak – Demand and Volumetric

Customer Charge	$20.00 per month
Billable Demand Charge	
Charges applicable for the months of June, July, August, and September	
On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$14.21 per kW
Off-Peak: All other hours of the week	$4.79 per kW
Charges applicable for all other months	
On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$10.94 per kW
Off-Peak: All other hours of the week	$4.79 per kW
Energy Delivery Charges	
Charges applicable for all months	
All kWhr	8.25 cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER AA – SC 2 INNOVATIVE PRICING PILOT - Continued

G. Delivery Charges

Rate I – 12 Noon to 8 PM Summer and Non-Summer On-Peak

Customer Charge	$33.00 per month
Billable Demand Charge	
Charges applicable for the months of June, July, August, and September	
On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$29.56 per kW
Off-Peak: All other hours of the week	$11.49 per kW
Charges applicable for all other months	
On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$22.75 per kW
Off-Peak: All other hours of the week	$11.49 per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

Supply Charges

Full Service Customers are subject to the supply and supply-related charges and adjustments specified in General Rule 25. Retail Access Customers are not subject to General Rule 25.

Increase in Rates and Charges

The rates and charges under this Rider are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

Billable Demand

For each day in a billing cycle, the maximum daily demand shall be calculated for each time period applicable to that day. The Billable Demands shall be determined by calculating the average of the three highest maximum daily demands occurring in each time period for the applicable billing period. All maximum daily demand values shall be established by calculating the highest integrated 60-minute demand ending in each day and being entirely comprised of intervals ending in the same time period (on-peak, off-peak).

GENERAL RULES

24. Service Classification Riders (Available on Request) – Continued

RIDER AB – SMART HOME RATE - Continued

F. Charges

Customers will be assigned to one of the following rates by the Company.

Rate I

Delivery Charges

Customer Charge — $20.00 per month

Daily Demand Charges

For each day in the billing cycle, the maximum Daily Demand shall be the highest integrated 60-minute demand occurring entirely between the hours of Noon and 8 PM.

Charges applicable for all months

Daily Demand Charge — $1.89 per kW

Critical Peak Distribution and Transmission Event Charges

On any day of the year, the Company may declare Critical Peak Distribution Events and Critical Peak Transmission Events. The Company may declare up to 10 events of each of the two types per 12-month period. During any declared event, the Customer's highest integrated 60-minute demand occurring entirely during the declared event period shall serve as the basis for the Customer's billable demand for the event. A maximum of one event of each type may be declared on a single day; however, multiple types of events may be declared on the same day at any time. Each event shall be billed separately. If a Customer exports power during an event and has a maximum integrated 60-minute demand occurring entirely during the declared event period of less than zero, the Customer shall receive a credit for the minimum integrated 60-minute level of export at the Critical Peak Event Charge applicable to that event.

Charges applicable for all months

Critical Peak Distribution Event Charge(s)	$3.22 per kW per Event
Critical Peak Transmission Event Charge(s)	$0.81 per kW per Event

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

GENERAL RULES

25. Supply and Supply-related Charges and Adjustments - Continued

25.1 Market Supply Charge

The Market Supply Charge ("MSC") varies by Service Classification and rate class and will be calculated based on best available information, as described below. MSC amounts will be billed in cents per kilowatthour for energy-only Service Classifications and in both dollars per kilowatt and cents per kilowatthour for demand-billed Service Classifications.

The Factor of Adjustment for Losses is 1.071 to account for losses of 6.6 percent.

(a) The MSC includes the following cost components, adjusted by the Factor of Adjustment for Losses, except as described below:

(1) the cost of energy based on NYISO market prices;
(2) the cost of capacity based on NYISO market prices;
(3) ancillary services charges, including certain NYISO Schedule 1 charges, such as the Scheduling, System Control & Dispatch ("S, SC & D") Service Charge, Local Reliability S, SC & D Service Charge and Market Administration and Control Area Service Charge, and any other NYISO commodity-related charges;
(4) NYPA Transmission Adjustment Charge (“NTAC”);
(5) NYISO charges allocated to the Company resulting from transmission projects approved through FERC, NYISO and/or Commission processes (“NYISO Transmission Charges”); and
(6) certain other transmission-related charges and credits.

The Factor of Adjustment for Losses is not applicable to capacity costs billed to Rider M Customers, because their ICAP tags are inclusive of losses.

GENERAL RULES

25. Supply and Supply-related Charges and Adjustments - Continued

25.1 Market Supply Charge - Continued

(b) - Continued

The MSC per-kilowatthour rate for each Customer in an energy-only rate class, which for this purpose includes Customers taking service under Rider Z, Rider AA, and Rate IV of SC 1, will be the sum of components (1) through (5) in (a) above, that is, the cost of energy and capacity based on NYISO market prices plus the Ancillary Services Charges, NTAC, and NYISO Transmission Charges. Energy-only SC 12 Customers subject to the Minimum Charge are assessed the MSC per-kilowatthour rate based on the minimum kWhr billed. For accounts billed under: Rate II of SC 1 or SC 2; Rate III of SC 1; Rate IV of Rider Z; or Rate IV of SC 1, component (1) in (a) above, that is, the cost of energy, will be the cost of energy based on NYISO market prices load-weighted by the applicable rate class's hourly load shape (as described in General Rule 25.1(b)) for the applicable time-of-day periods. For accounts billed under Rate II of SC 1 or SC 2, component (2) in (a) above, that is, the cost of capacity, is only assessed for usage during the "on peak" period. For accounts billed under Rate III of SC 1, component (2) in (a) above is only assessed during the Summer Billing Period, weekdays, 2 PM to 6 PM. For accounts billed under Rate IV of Rider Z and Rate IV of SC 1, the cost of capacity is assessed only for usage during the "on peak" period.

For Customers billed under Rate I of Rider AB, the cost of capacity is recovered through Critical Peak Generation Capacity Event Charges, on a per kW basis. For Customers billed under Rate II of Rider AB, the cost of capacity is recovered through Generation Capacity Subscribed Demand Charges, on a per kW of Subscribed Demand basis, as well as through Critical Peak Generation Capacity Event Charges, on a per kW basis, assessed based on kW during Critical Peak Generation Capacity Events in excess of Customers' Generation Capacity Subscribed Demands.

The MSC per-kilowatthour rate for each Customer in a demand-billed rate class will be the sum of components (1), (3), (4), and (5) in (a) above. For demand-billed rate classes, component (2) in (a) above, that is, capacity costs, will be billed as a separate per-kilowatt MSC rate. Except as described below, the cost of capacity is billed to Customers in demand-billed rate classes per kW of registered demand. Capacity costs are only assessed for demand registered weekdays, 8 AM to 6 PM, during the Summer Billing Period and weekdays, 8 AM to 10 PM, during the Winter Billing Period for accounts billed under SC 13, Rate II or IV of SC 5, or Rate II, III, or V of SC 8, 9, or 12. Exceptions are as follows:

(1) Non-Rider M demand-billed Customers subject to the Minimum Charge are assessed the MSC per-kilowatt rate based on the minimum kW billed.

(2) Rider M Customers are assessed the MSC per-kilowatt rate based on their ICAP Tag, commencing with bills having a "from" date on or after June 1, 2016. Each Customer's ICAP Tag, expressed in kW, is set annually, each May 1, based on that Customer's load during the NYCA peak hour from the prior calendar year, reconciled to the Company's share of the NYCA peak load, and adjusted for the upcoming year's forecasted peak load. In the event the Company does not have an accurate or sufficient load history for the Customer's account, the ICAP tag will be based on the Company's estimate.

GENERAL RULES

25. Supply and Supply-related Charges and Adjustments - Continued

25.2 Adjustment Factors – MSC

The Adjustment Factors – MSC are applicable to all Full Service Customers subject to the MSC, except for Customers served under Rider M.

25.2.1 Adjustment Factor – MSC I

The components of the Adjustment Factor - MSC I are described below.

a. MSC Reconciliation

Estimated MSC amounts recovered in rates on a calendar month basis shall be reconciled to actual MSC costs on a calendar month basis. The actual MSC costs include the costs the Company would have incurred if the requirements to serve Customers under this Rate Schedule would have been purchased solely from the NYISO market calculated on a load-weighted average market price based on available NYISO billing data at the end of each month. These costs will be increased by the value of any capacity credits that the Company receives from pledging MW associated with the Direct Load Control Program into the NYISO Special Case Resources program, priced at the strip auction price for the capability period and determined separately for the New York City and the combined Westchester NYISO zones. These costs will also be increased by the total Value Stack Energy Component credits paid out to both Customers served under the Value Stack Tariff as described in Rider R of this Rate Schedule and to Customers served under the Value Stack Tariff for PASNY Customer-Generators General Provision of the PASNY Rate Schedule. The Adjustment Factor – MSC I will include separate reconciliation amounts for New York City and for the combined Westchester NYISO zones.

b. Tax Reimbursement Recovery Provision

The Company is authorized by Section 66-h of the Public Service Law to recover tax reimbursements that it makes to non-utility generators pursuant to such law. The Adjustment Factor – MSC I will recover such tax reimbursements only from Customers with non-residential use of electricity, as explained hereunder.

c. Demand Response Program Cost Recovery Provision

The Company is authorized to recover the difference, if any, between (i) the amounts billed in such month to Customers served under Rider M for actual energy usage priced at the applicable hourly energy prices in accordance with the provisions of Rider M, and (ii) the actual market supply costs for such month for such Customers' actual energy usage.

GENERAL RULES

25. Supply and Supply-related Charges and Adjustments - Continued

25.3 Merchant Function Charge

The Merchant Function Charge ("MFC") is applicable to all Full Service Customers subject to the MSC. The MFC is determined on a calendar-month basis and is equal to the sum of the following components:

(a) a competitive supply-related charge, inclusive of a charge for purchased power working capital, in cents per kilowatthour, as shown below:

Service Classification	Effective Jan. 2023
SC 1	0.1517
SC 2	0.1237
SCs 5, 6, 8, 9, 12, and 13	0.0822

(b) a credit and collection-related charge, in cents per kilowatthour, as shown below:

Service Classification	Effective Jan. 2023
SC 1	0.1996
SC 2	0.1417
SCs 5, 6, 8, 9, 12, and 13	0.0329

(c) a charge or credit to reflect the Transition Adjustment amount (including any Reconciliation Amounts from the prior Rate Year's Transition Adjustment and prior period deferrals, plus interest) applicable to Full Service Customers, pursuant to General Rule 28; and

GENERAL RULES

25. Supply and Supply-related Charges and Adjustments - Continued

25.3 Merchant Function Charge - Continued

(d) a charge for the Uncollectible-bill Expense associated with the MSC and Adjustment Factors – MSC charges. The Uncollectible-bill Expense will be determined each month for Customers subject to the MFC in SC 1 (the "Residential Class") based on an estimate of costs recoverable through the MSC and Adjustment Factors – MSC charges for the Residential Class and an Uncollectible Bill Factor of 0.0072. For Customers subject to the MFC in other SCs (the "Other Classes"), the Uncollectible-bill Expense will be determined each month based on an estimate of costs recoverable through the MSC and Adjustment Factors – MSC charges for the Other Classes and an Uncollectible Bill Factor of 0.0028. The resulting Uncollectible-bill expenses for the Residential Class and Other Classes will then be adjusted to reflect a system Uncollectible Bill Factor of 0.0046. Any difference between the monthly Uncollectible-bill Expense as determined above and the Uncollectible-bill Expense determined for the Residential Class based on billed MSC and Adjustment Factors - MSC charges will be collected from or credited to the Residential Class through the Uncollectible-bill Expense determined for the Residential Class in a subsequent month. Any difference between the monthly Uncollectible-bill Expense as determined above and the Uncollectible-bill Expense determined for the Other Classes based on billed MSC and Adjustment Factors – MSC charges will be collected from or credited to the Other Classes through the Uncollectible-bill Expense determined for the Other Classes in a subsequent month. The Company will true-up its Uncollectible Bill Expense for the MSC and Adjustment Factors – MSC charges for the Residential Class and for Other Classes using the Uncollectible Bill Factor applicable to electric and gas customers for the 12-month period through the previous September.

At least once every 12 months, the Company will reconcile the Uncollectible-bill Expense required to be collected with the amounts billed, and any under-recovery or over-recovery will be passed through the Uncollectible-bill Expense applicable to both the Residential Class and the Other Classes, with interest, in a subsequent month. Interest will be calculated at the Other Customer Capital Rate.

Each component of the MFC will be charged on a cents per-kilowatthour basis, taken to the nearest 0.0001 cent. The Company will file a Statement of Merchant Function Charge ("Statement"), apart from this Rate Schedule, showing the MFC amount per kilowatthour in effect for the calendar month and the date on which the MFC was determined. Amounts will be separately shown for the following: (i) Customers billed under SC 1, (ii) Customers billed under SC 2, and (iii) Customers billed under SC 5, 6, 8, 9, 12, and 13. Unless otherwise directed by the Commission, the Company will file Statements no less than three days prior to MFC changes.

GENERAL RULES

26. Additional Delivery Charges and Adjustments

Except as specified within each section of this General Rule, the following charges are applicable to all Customers served under this Rate Schedule:

(a) Monthly Adjustment Clause (“MAC”) and Adjustment Factor – MAC;
(b) Revenue Decoupling Mechanism (“RDM”) Adjustment;
(c) Billing and Payment Processing (“BPP”) Charge;
(d) System Benefits Charge (“SBC”);
(e) Clean Energy Standard Delivery Surcharge (“CESD”);
(f) Dynamic Load Management (“DLM”) Surcharge;
(g) Delivery Revenue Surcharge;
(h) Value of Distributed Energy Resources (“VDER”) Cost Recovery;
(i) Tax Sur-credit; and
(j) EV Make-Ready Surcharge

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.1 MAC Components - Continued

(5) charges for and/or revenues from the Company's system TCCs that are not sold;

(6) any non-commodity related charges or credits, not otherwise recovered through the MSC or Adjustment Factors – MSC, related to FERC approved or ordered NYISO or PJM rebills or recalculations of charges paid by NYISO or PJM customers;

(7) carrying charges related to the Rainey to Corona Project, the Gowanus to Greenwood Project, and the Goethals to Fox Hills Project, collectively, the Reliable Clean City ("RCC") projects, less costs allocated to the PASNY Rate Schedule, as authorized by the Commission's April 15, 2021 Order in Case 19-E-0065;

(8) certain NYISO-related charges and credits, including all rebills issued to the Company prior to May 1, 2008, non-commodity-related rebills issued to the Company beginning May 1, 2008, and NYISO Schedule 1 charges that are not covered under the MSC. Miscellaneous charges/credits to be flowed through the MAC, such as rebills, will be limited to five percent of the total MSC/MAC costs for that month. Residual amounts will be deferred with interest and flowed through the MAC in subsequent month(s) subject to the same five percent limitation;

(9) Customers' share of the cost of the savings passed on to eligible Customers in accordance with Section 3, Chapter 459, 1982 N.Y. Laws;

(10) carrying charges associated with interference costs causing an exceedance of the net electric plant target, less amounts allocated for collection under the PASNY Rate Schedule;

(11) amount by which annual storm costs exceed the annual rate allowance, when such excess amount exceeds $7 million each year, up to 2.5 percent of delivery revenue each year, less amounts allocated for collection under the PASNY Rate Schedule;

(12) certain NYISO Transmission Owners Charges such as Congestion Balancing Settlement, Rochester Station 80 Capacitor Bank and Ramapo Phase Angle Regulator and any other transmission-related charges;

(13) net revenues from sales to other utilities, LSEs and others;

(14) certain other transmission-related charges and credits;

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.1 MAC Components - Continued

(15) the difference between costs used in the calculation of the Adjustment Factors – MSC and total actual costs incurred, including all costs incurred and benefits received prior to May 1, 2008 from financial hedging instruments associated with transactions intended to reduce price volatility to customers (e.g., transaction costs, such as option premiums, costs of providing credit support and margin requirements, and professional fees, and gains and losses associated with such transactions made in the commodities exchanges and with other counterparties);

(16) foregone delivery service revenues associated with the provision of service under Rider M (voluntary service only), and the Company's Direct Load Control Program to the extent such revenues are not recovered through a revenue decoupling mechanism.

(17) foregone electric revenues resulting from decreased electric requirements associated with steam air conditioning installations by Customers under Special Provision E of Service Classification Nos. 2 and 3 of Con Edison's Schedule for Steam Service, P.S.C. No. 4 - Steam to the extent such revenues are not recovered through a revenue decoupling mechanism;

(18) foregone steam revenues associated with steam rate discounts for steam air conditioning installations by Customers under Special Provision E of Service Classification Nos. 2 and 3 of Con Edison's Schedule for Steam Service, P.S.C. No. 4 - Steam;

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.1 MAC Components - Continued

(19) all costs on an as-incurred basis, including but not limited to payments to Customers where applicable and capital costs for enabling technologies, associated with the implementation of programs conducted under Rider M, the Distribution Load Relief Program (“DLRP”) under Rider T, the Company’s Direct Load Control (“DLC”) Program, the steam rate discount under Special Provision E of Service Classification Nos. 2 and 3 of Con Edison’s Schedule for Steam Service, P.S.C. No. 4 - Steam, and the Company’s marketing program for demand response programs; provided, however, that DLRP cost recovery will exclude any “lost” Summer payments made pursuant to the Commission’s order issued April 8, 2009, in Cases 08-E-1463 and 08-E-0176, and DLRP cost recovery through the MAC beginning with costs incurred for the 2011 summer program will be equal to the total program costs less the program costs allocated for collection under the PASNY Rate Schedule pursuant to the Commission’s Order issued January 20, 2011, in Case 10-E-0530. DLRP and DLC Program costs incurred on and after May 1, 2018 will be recovered through the Dynamic Load Management Surcharge;

(20) all costs related to deferred late payment fees and other fees originally associated with Customer non-payment (“Unbilled Fees”) for Rate Year One (i.e., 2020) as authorized by the Commission in Case 19-E-0065. The Company will recover these Unbilled Fees commencing December 1, 2021, through December 31, 2022. The Company will reconcile the approved fees in Rate Years Two (i.e., 2021) and Three (i.e., 2022) in Case 19-E-0065 without any threshold requirement and collect/pass back any variance. The Company will begin its recovery or pass back of the approved fees for Rate Year Two on January 1, 2023, through December 31, 2023 and for Rate Year Three on January 1, 2024, through December 31, 2024. The Company will reconcile the actual annual late payment fee revenues with Commission approved levels included in base rates in 2023 and future years and collect/pass back any variance over a subsequent twelve-month period as authorized by the Commission. The amount to be recovered or passed back will be determined by subtracting amounts allocated for collection under the PASNY Rate Schedule and dividing the resulting amount to be recovered or passed back over the collection period by the number of months in the collection period;

(21) the difference, plus interest, between the actual annual UB expense and Commission approved levels in rates for the period January 1, 2020 through December 31, 2025. After that time, the Company may recover any under-collections. Additionally, a charge or credit will be included for the reconciliation of the non-Credit and Collections related portion of the POR Discount reconciliation. The amounts to be recovered or passed back under this provision will be reduced by the amounts allocated for collection under the PASNY Rate Schedule;

(22) the Company’s costs on an as-incurred basis, including marketing costs and costs for program evaluation, staffing, program development and market research, for both targeted and other demand management programs that the Company implements or helps to implement as well as any demand management program-related incentives, other than costs addressed in MAC components 19 and 33;

(23) the difference between the actual annual property taxes and Commission approved levels in base rates, less amounts allocated to the PASNY Rate Schedule;

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.1 MAC Components - Continued

(24) any net revenue shortfalls between delivery rates under this Rate Schedule and NYPA delivery rates resulting from laws that would permit NYPA to serve non-governmental Customers in the Company's service area;

(25) any difference between the level of NEIL distributions reflected in rates and the actual NEIL distributions received on an annual basis;

(26) any variance between the wholesale Transmission Service Charge revenues reflected in base rates and the actual wholesale Transmission Charge revenues received, other than from firm transmission contracts, on an annual basis net of any NYISO-related adjustments;

(27) any variance between the wheeling revenues for firm Transmission contracts reflected in rates and the actual wheeling revenues for firm Transmission contracts received on an annual basis;

(28) the electric department's allocated share of common costs for the 59th and 74th Street Stations;

(29) costs, as incurred, related to the Regional Greenhouse Gas Initiative ("RGGI"), to the extent such costs are not recoverable through the market prices reflected in the Market Supply Charge, with respect to Company-owned generating facilities;

(30) revenues received from the sale of RGGI allowances;

(31) costs incurred pursuant to Section 185 of the Clean Air Act;

(32) a credit equal to the value of any adjustment made to the Adjustment Factor – MSC I for capacity associated with the Direct Load Control Program that is pledged into the NYISO Special Case Resources program and a credit for payments received from NYSERDA or any other source for Direct Load Control installations;

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.1 MAC Components - Continued

(33) all program costs, as incurred, to be collected over a reasonable period of time, for Commission approved Energy Efficiency and Demand Response Programs to the extent not recovered through another mechanism, less costs allocated for collection under the PASNY Rate Schedule;

(34) [RESERVED FOR FUTURE USE];

(35) [RESERVED FOR FUTURE USE];

(36) amounts associated with rate reductions provided to Customers under the COVID-19 BIR program, less amounts allocated to the PASNY Rate Schedule;

(37) [RESERVED FOR FUTURE USE];

(38) all PJM OATT rates and charges associated with the 1,000 MW firm transmission service contracted with PJM that are applicable to the period April 1, 2013 through December 31, 2013, net of the amount of PSEG wheeling charges reflected in rates during that period. The rates and charges recovered through the MAC will be equal to the total rates and charges less the PJM OATT rates and charges collected under the PASNY Rate Schedule. Collections will commence March 2014 and will be made over a 10-month period;

(39) all PJM OATT rates and charges associated with the 1,000 MW firm transmission service contracted with PJM that are applicable to the period commencing January 1, 2014, less the PJM OATT rates and charges collected under the PASNY Rate Schedule. Commencing March 2014, rates and charges will be collected monthly as incurred and will include an adjustment to recover over a three-month period rates and charges applicable to the period January and February 2014;

(40) the commodity-related component of customer credits provided under the SC 1 Rate III price guarantee for plug-in electric vehicles and customer credits provided under the price guarantees of Rider Z, Rider AA, and Rider AB;

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.1 MAC Components - Continued

(41) costs, as incurred, related to the purchase of emissions allowances for Company-owned generating facilities pursuant to the Environmental Protection Agency's final rule on interstate transport of fine particulate matter and ozone, dated August 8, 2011, as the same may be modified from time to time, to the extent such costs are not recoverable through the market prices reflected in the Market Supply Charge;

(42) revenues received from the sale of emissions allowances pursuant to the Environmental Protection Agency's final rule on interstate transport of fine particulate matter and ozone, dated August 8, 2011, as the same may be modified from time to time;

(43) costs related to the Brooklyn/Queens Demand Management Program, less costs allocated to the PASNY Rate Schedule, other than costs recovered in base rates;

(44) Standby Performance Credits and Standby Reliability Credits provided to Customers served under this Rate Schedule pursuant to General Rule 20.5.3 and General Rule 20.5.4;

(45) costs related to the Targeted Demand Management program and Reforming the Energy Vision Demonstration Projects, less costs allocated to the PASNY Rate Schedule, other than costs recovered in base rates;

(46) any positive incentives earned under Earnings Adjustment Mechanisms, any other incentives associated with Company incentive mechanisms, and revenue adjustments associated with Company performance metrics and mechanisms, less amounts allocated for collection under the PASNY Rate Schedule as applicable, and as authorized by the PSC;

(47) [RESERVED FOR FUTURE USE];

(48) costs for implementation of Non-Wires Alternatives ("NWA") (adjusted for the carrying charge of any displaced capital project reflected in the Average Electric Plant in Service Balance that would otherwise be deferred for customer benefit), plus NWA incentives earned by the Company, less amounts allocated for collection under the PASNY Rate Schedule;

(49) bill credits provided to export-only Customers pursuant to Special Provision I of SC 11, less amounts allocated for collection under the PASNY Rate Schedule;

(50) [RESERVED FOR FUTURE USE]

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

26.1.2 Adjustment Factor - MAC

The Adjustment Factor – MAC includes the following components. Each component, applied on a cents per kilowatthour basis to the nearest 0.0001 cent, is determined by dividing the amount to be collected or credited by the sum of the estimated sales in kWhr to all Customers subject to the MAC over the period for which the adjustment is to be applied:

(a) MAC Reconciliation

The Company will reconcile the estimated MAC amount recovered in rates on a calendar month basis to actual MAC costs on a calendar month basis. Rates under all Service Classifications shall be subject each month to an adjustment reflecting the MAC reconciliation amount.

The amounts recovered or credited through the MAC Reconciliation component of the Adjustment Factor - MAC will be reconciled to actual amounts to be recovered. Any differences will be passed through the Adjustment Factor - MAC in a subsequent month.

(b) Uncollectible-bill Expense

The Adjustment Factor – MAC will contain a separate charge to reflect the Uncollectible-bill Expense associated with MAC and Adjustment Factor – MAC charges. The Uncollectible-bill Expense will be determined each month by multiplying an estimate of costs recoverable through the MAC and the MAC Reconciliation component of the Adjustment Factor – MAC charges by an Uncollectible Bill Factor of 0.0046. Any difference between the monthly Uncollectible-bill Expense as determined above and the Uncollectible-bill Expense determined by multiplying the Uncollectible Bill Factor by the billed MAC charges and the billed MAC Reconciliation component of the Adjustment Factor – MAC charges will be collected from/credited to Customers through the Uncollectible-bill Expense determined in a subsequent month. The Company will true-up its Uncollectible Bill Expense for the MAC and the MAC Reconciliation component of the Adjustment-Factor – MAC charges using the Uncollectible Bill Factor approved in Case 16-E-0060 for charges determined through December 31, 2019, and the Uncollectible Bill Factor applicable to electric and gas customers for the 12-month period through the previous September.

At least once every 12 months, the Company will reconcile the Uncollectible-bill Expense required to be collected with the amounts billed, and any under-recovery or over-recovery will be passed through the Uncollectible-bill Expense, with interest, in a subsequent month. Interest will be calculated at the Other Customer Capital Rate.

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.1 Monthly Adjustment Clause - Continued

[RESERVED FOR FUTURE USE]

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.2 Revenue Decoupling Mechanism Adjustment - Continued

(3) Allowed Pure Base Revenue

Allowed Pure Base Revenue* (in $000s), by SC, is as follows:

SC	Jan. – Dec. 2022	Jan. – Dec. 2023**
1	$2,347,535	To be determined
2 and 6	$510,989	To be determined
5 and 9	$2,320,689	To be determined
8	$171,813	To be determined
12	$27,163	To be determined

* Allowed Pure Base Revenue amounts shown above do not reflect Low Income Discounts starting January 2018.
**Revenue targets for each rate year thereafter will continue at these amounts unless and until changed.

Annual Allowed Pure Base Revenue will be revised whenever there is a change in Demand Delivery Charges, Energy Delivery Charges, or the Customer Charge applicable under one or more of the SCs. Furthermore, if, for any reason, an SC no longer has existing customers, the Allowed Pure Base Revenue for that SC will be reallocated to other SCs with existing Customers and to the PASNY Rate Schedule to provide for equitable treatment of revenue deficiencies from the discontinued class. In the event Allowed Pure Base Revenue is reallocated, the Company will notify the Department of Public Service Commission Staff of the revised Allowed Pure Base Revenue amount(s). The Company will be allowed to defer collection of any revenue shortfall or refund of any revenue surplus that results from a delay in the approval of a reallocation of Allowed Pure Base Revenue. SC 1 RDM amounts to be collected over each six-month RDM collection/refund period will be adjusted to recover the delivery-related component of customer credits provided under the SC 1 Rate III price guarantee for plug-in electric vehicles.

Since load served under Special Provision G ("RNY") and Special Provision H ("EJP") of SC 9 is exempt from the RDM, SC 9 Allowed Pure Base Revenue will be decreased/increased as appropriate for load transfers to or from RNY or EJP service.

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.2 Revenue Decoupling Mechanism Adjustment - Continued

(4) Low Income Program Costs

The Company will adjust each class's RDM amounts to be collected over each six-month RDM collection/refund period to reflect that class's share of the difference between actual Low Income Program costs and the amount of these costs included in rates (i.e., $118.82 million annually).

Any Low Income Program costs required to be collected or refunded will be passed through the RDM Adjustment that is applicable under this Rate Schedule and the RDM Adjustment applicable under the PASNY Rate Schedule. The amount to be collected or refunded through the RDM Adjustment applicable under this Rate Schedule will be equal to the total amount to be collected or refunded less the Low Income Program costs collected or refunded under the PASNY Rate Schedule.

Continuation of the Low Income Program beyond December 31, 2023, will be contingent on the continuation of full cost recovery through the RDM Adjustment or an equivalent mechanism.

(5) Costs Related to the Emergency Summer Cooling Credit

The Company will increase each class's RDM amounts to be collected after January 1, 2021 through the end of the Rate Plan in Case 19-E-0065, to reflect each class's share of amounts to be recovered during such period, as specified in the Commission's June 11, 2020 Order in Case 20-M-0231. Each class's share will reflect the partial recovery of costs related to the Emergency Summer Cooling Credit as specified under SC 1 Special Provision I.

This recovery of the costs related to the Emergency Summer Cooling Credit will be passed through the RDM Adjustment that is applicable under this Rate Schedule and the RDM Adjustment applicable under the PASNY Rate Schedule. The amount to be collected shall be offset by the revenue from the Emergency Summer Cooling Credit component of the CBC Charge described in Rider R of this Rate Schedule. The amount to be collected through the RDM Adjustment applicable under this Rate Schedule will be equal to the total amount to be collected less the costs related to the Emergency Summer Cooling Credit collected under the PASNY Rate Schedule.

GENERAL RULES

26. Additional Delivery Charges and Adjustments - Continued

26.10 EV Make-Ready Surcharge - Continued

EVMR Cost Recovery will be determined:

(1) annually, commencing with Customer bills having a "from" date on or after February 1, 2021 with the first EVMR Surcharge recovering costs for the period July 16, 2020 through December 31, 2020 and each subsequent EVMR Surcharge recovering costs for January 1 through December 31 periods thereafter;

(2) for each service classification or rate class in proportion to each class' delivery revenues;

(3) on a kWhr basis for non-demand billed service classification groups, on a kW basis for demand billed service classification groups, Monday through Friday, 8 AM to 10 PM, year-round, for Rate II of SC 5 and Rate II and Rate III of SCs 8, 9, and 12 (for Customers billed on Standby Service rates the surcharge will be collected on a per kW of Contract Demand basis), or on a dollar per month basis;

(4) with the rate per kWh or kW determined by dividing allocable costs by estimated billed kWh deliveries or kW demand over the collection period;

(5) by reconciling the EVMR Surcharge at the end of each program year. Any over- or under-collection as a result of this reconciliation will be reflected in the following EVMR Surcharge.

(6) by the costs, other than costs recovered in base rates.

The EVMR Surcharge will be applicable to all delivery customers served under SCs 1, 2, 5, 6, 8, 9, 11, 12 and 13. Amounts collected under this Rate Schedule will be equal to the total program costs less the program costs allocated for collection under the PASNY Rate Schedule. The EVMR Surcharge is not applicable to Customers served under the Excelsior Jobs Program, SC 9 Special Provision H.

The unit amounts to be collected will be shown on the Statement of EVMR Surcharge filed with the Public Service Commission apart from this Rate Schedule. Unless otherwise directed by the Commission, the Company will file each Statement no less than fifteen days before its effective date.
For purposes of billing, the EVMR Surcharge will be included with the Monthly Adjustment Clause.

27. [RESERVED FOR FUTURE USE]

GENERAL RULES

28. Transition Adjustment for Competitive Services

28.1 Applicability

A Transition Adjustment will be determined for Customers served under this Rate Schedule, except for Customers served under SC 11.

28.2 Components of the Transition Adjustment

The Transition Adjustment will be the sum of the following components, based on the 12 months ending December, except as described in General Rule 28.3:

(a) the difference between the targeted level of revenues from competitive supply-related charges (including purchased power working capital) reflected in the Merchant Function Charge ("MFC") and billed revenues from the competitive supply-related component of the MFC. The MFC supply-related revenue (including purchased power working capital) target is $26,428,898 for the twelve-month period commencing January 1, 2023;

(b) the difference between the targeted level of revenues from competitive credit and collection-related charges reflected in the MFC and billed revenues from the competitive credit and collection-related components of the MFC. The MFC credit and collection-related target is $26,972,712 for the twelve-month period commencing January 1, 2023;

(c) the Company's lost revenues attributable to the Billing and Payment Processing ("BPP") Charge. The lost revenues attributable to the BPP will be equal to the total BPP charges that are avoided by Customers (as detailed in General Rule 26.3) less charges paid by ESCOs for Company-issued Consolidated Bills less costs avoided by the Company when ESCOs issue Consolidated Bills; and

(d) prior to January 1, 2019, the difference between the targeted level of credit and collection costs reflected in the Purchase of Receivables ("POR") Discount Percentage applicable to ESCOs under the POR program and revenues from the credit and collection-related component reflected in the POR Discount Percentage. Effective January 1, 2019, this difference, and any prior period reconciliations, will be reflected in the Credit and Collections component of the POR Discount Percentage as described in General Rule 19.3.6. The revenue target is $7,736,100 for the twelve-month period commencing January 1, 2023.

GENERAL RULES

Application Forms – Continued

Form G – Application for Rider R or Standby Service and/or Buy-Back Service- Continued

Section 5. If you request Standby Service or Standby Service rates – Continued

D. Electricity Supply

Con Edison will provide electricity supply to supplement your on-site generation or when your generation is not running, unless: (a) you enroll in the Retail Access Program through an ESCO or as a Direct Customer, as described in General Rule 19; or (b) you are a Customer that is a Wholesale Generator and do not apply in writing to be a Full Service Customer, as described in General Rule 20.6; or (c) you are enrolled in other non-Company Supply service programs. Please leave this section blank if you plan on purchasing supply from Con Edison or through an ESCO. Check below if:

- ❑ You plan to be a Direct Customer.
- ❑ You plan to be a Customer that is a Wholesale Generator taking Standby Service for Station Use.

E. Standby Offset Options

Standby Offset customers must meet requirements for efficient CHP are described in Section 7 of this Addendum Application. Under Standby Offset, your premises will be supplied by efficient CHP that is rated over 2 MW and connected to the Company's high-tension distribution system. Check below for the applicable Standby Offset option:

- ❑ You request Standby Service for a single-low tension account pursuant to General Rule 20.4.5 of the rate schedule.
- ❑ You request Standby Service for two or more of your accounts at your premises pursuant to the Single Party Offset, as described in General Rule 20.4.6 of the rate schedule.
- ❑ You request Standby Service as a Sponsor pursuant to the Multi-Party Offset, as described in General Rule 20.4.6 of the rate schedule.

GENERAL RULES

Application Forms – Continued
Form G – Application for Rider R or Standby Service and/or Buy-Back Service- Continued

Section 5. If you request Standby Service or Standby Service rates – Continued

F. Contract Demand

Contract Demand can be set by you or by the Company, as described in General Rule 20.4.3 of the rate schedule. The Company will determine your Contract Demand unless you state your Contract Demand below. The Contract Demand set by a Customer is subject to review and approval by the Company unless the generation is installed at an existing premises with no increase in load or capacity requirements for an account other than one requesting service under General Rule 20.4.5 or General Rule 20.4.6. For service under General Rule 20.4.5 or General Rule 20.4.6, changes to the accounts supplied by the generating facility's output requested between February 1 through March 1 of each year will be effective for bills issued with a "from" date in May. Changes to the accounts requested between August 1 through September 1 of each year will be effective for bills issued with a "from" date in November. Please refer to General Rule 20.4.5 or General Rule 20.4.6(c)(6) for all applicable rules.

Check below if applicable:
❑ The generator is being installed at an existing premises with no increase in load or capacity requirements.

If you set your own Standby Service Contract Demand, please specify:

- Contract Demand, unless you request service under General Rule 20.4.6:
  (Low Tension)__________kW or (High Tension) _________kW

- For service under the Single Party Offset pursuant to General Rule 20.4.6, please provide below the Contract Demand for each account to be served:

Account #	Service Address	Contract Demand kW	Low Tension or High Tension

(Attach a sheet if you have additional accounts.)

For service requested under the Multi-Party Offset pursuant to General Rule 20.4.6:
(a) Each Customer that will receive an allocation of the generating facility's output ("Recipient Account") must complete and sign a Multi-party Offset Recipient Participation Form, which includes space for the Customer to set its own Contract Demand, and provide it to the Sponsor to submit with this application Form G.
(b) The Sponsor must complete and submit a signed Multi-Party Offset Percentage Allocation Form, which includes identification of the Recipient Accounts and the percentage of the generator's output to be allocated to each.

FOR COMPANY USE ONLY
Contract Demand set by Company, if required: (Low Tension)__________kW or (High Tension) _________kW
Company's approval if the Customer set the Contract Demand, if required: ____________________

GENERAL RULES

Application Forms – Continued
Form G – Application for Rider R or Standby Service and/or Buy-Back Service- Continued

Section 5. If you request Standby Service or Standby Service rates – Continued

G. Standby Rate Pilot

If you request to participate in the Standby Rate Pilot under Rider Q of this rate schedule, please check the box(es) that apply. Please also fill Section 7A of this Addendum Application:

❑ Option A – Customer Chooses Contract Demand

Please specify the Contract Demand you choose below. Please also specify the Contract Demand in Section F as if the Customer were not taking service under this Option:

(Low Tension)_________kW or (High Tension) ________kW

❑ Option B - Locational Variant Daily As-used Demand Pricing

H. Option under General Rule 20.4.7 of this rate schedule:

If you request to participate pursuant to General Rule 20.4.7 of this rate schedule, please check the below box. Customers must meet requirements for efficient CHP as described in Section 7 of this Addendum Application.

❑ You request Standby Service pursuant to General Rule 20.4.7 of this rate schedule.

SERVICE CLASSIFICATION NO. 1
RESIDENTIAL AND RELIGIOUS

Applicable to Use of Service for

Light, heat, and power, when supplied directly by the Company to any single-family dwelling or building or to any individual flat or apartment in a multiple-family dwelling or building or portion thereof occupied as the home, residence or sleeping place of the Customer, an employee of the Customer, or a tenant of the Customer in a multi-family dwelling converted from rent inclusion to direct metering provided the tenant has a Rent Increase Exemption pursuant to rules of the State Division of Housing and Community Renewal. Light, heat, and power when supplied directly by the Company and selected by: any corporation or association organized and conducted in good faith for religious purposes, where such electric service is utilized exclusively in connection with such religious purposes; to a community residence; or to a post or hall owned or leased by a not-for-profit corporation that is a veterans' organization; or for the sole purpose of plug-in electric vehicle charging pursuant to Special Provision F. Service hereunder is subject to the Common Provisions and Special Provisions of this Service Classification.

Character of Service

Of the various characteristics of service listed and more fully described in General Rule 4, the following may be designated for service by the Company under this Service Classification, subject to the limitations set forth in such Rule. Frequencies and voltages shown are approximate. All are continuous.

Standard Service

Any derivative of the standard alternating current, 3 phase, 4 wire system at 60 cycles and 120/208 volts.

Non-Standard Service

Low Tension Alternating Current - 60 cycles:

Single Phase at 120/240 volts
Three phase at 265/460 volts
Three phase at 240 volts
Two phase at 120/240 or 230 or 240 volts

High Tension Alternating Current – 60 cycles:

Three phase at 2,400/4,150 volts
Three phase at 3,000/7,800 volts
Three phase at 6,900 volts
Three phase at 13,200 volts
Three phase at 26,400 volts
Three phase at 33,000 volts
Single phase and three phase at 2,400 volts
Three phase at 69,000 volts
Three phase at 138,000 volts

SERVICE CLASSIFICATION NO. 1 - Continued
RESIDENTIAL AND RELIGIOUS

Rate I - Residential and Religious

Applicability: To all Customers other than those billed under Rate II or Rate III.

Delivery Charges, applicable to all Customers

Customer Charge

$20.00 per month

Energy Delivery Charges

Charges applicable for the months of June, July, August, and September	
first 250 kWhr	15.532 cents per kWhr
over 250 kWhr	17.856 cents per kWhr
Charges applicable for all other months	
All kWhr	15.532 cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 1 - Continued
RESIDENTIAL AND RELIGIOUS

Rate II - Residential and Religious - Voluntary Time-of-Day

Applicability:

To Customers who made an election before March 1, 2014, to be billed at a time-of-day rate or under Special Provision D.

A Customer served under Rate II may elect to transfer to Rate I or Rate III, provided, however, that the Customer will thereafter be ineligible to return to Rate II.

Applications for service under this Rate will not be accepted on or after March 1, 2014.

Delivery Charges, applicable to all Customers

1) Applicable to accounts served under Special Provision D:

Energy Delivery Charges

Charges applicable for all months

Off peak: Monday through Friday, 10 PM to 10 AM, and all hours Saturday and Sunday	2.39	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

2) Applicable to all other accounts:

Customer Charge

$20.00 per month

Energy Delivery Charges

Charges applicable for the months of June, July, August, and September

On peak: Monday through Friday, 10 AM to 10 PM, excluding Independence Day (July 4) and Labor Day (the first Monday in September)	62.59	cents per kWhr
Off peak: All other hours of the week	2.39	cents per kWhr

Charges applicable for all other months

On peak: Monday through Friday, 10 AM to 10 PM, excluding New Year's Day (January 1), Memorial Day (the last Monday in May), Thanksgiving Day (the fourth Thursday in November), and Christmas Day (December 25)	22.70	cents per kWhr
Off peak: All other hours of the week	2.39	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 1 - Continued
RESIDENTIAL AND RELIGIOUS

Rate III - Residential and Religious - Voluntary Time-of-Day

Applicability:

To Customers who elect to be billed at a time-of-day rate on or after March 1, 2014, or under Special Provision F.

A Customer who elects to transfer from Rate III to another rate will be ineligible for billing under this Rate for a period of one and one-half years from the date of such transfer.

A Customer who elects Rate III as a Retail Access Customer and then switches to Full Service must remain on Rate III as a Full Service Customer for one year from the date of the switch.
A Customer who elects Rate III as a Full Service Customer must remain on Rate III as a Full Service Customer for one year from the date of the switch.

Delivery Charges, applicable to all Customers

Customer Charge

$20.00 per month

Energy Delivery Charges

Charges applicable for the months of June, July, August, and September

On-peak: All days, 8 AM to midnight, including holidays	33.97	cents per kWhr
Off-peak: All other hours of the week	2.40	cents per kWhr

Charges applicable for all other months

On-peak: All days, 8 AM to midnight, including holidays	12.58	cents per kWhr
Off-peak: All other hours of the week	2.40	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 1 - Continued
RESIDENTIAL AND RELIGIOUS

Rate IV - Residential and Religious - Optional Demand-Based

Applicability:

This rate is available on an opt-in basis.

A Customer who elects to transfer from Rate IV to another rate will be ineligible for billing under this Rate for a period of one and one-half years from the date of such transfer.

Delivery Charges, applicable to all Customers

Customer Charge $29.00 per month

Billable Demand Charge

Charges applicable for the months of June, July, August, and September

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$24.32	per kW
Off-peak: All other hours of the week	$7.17	per kW

Charges applicable for all other months

On-Peak: Weekdays, excluding holidays, 12 Noon to 8 PM	$18.70	per kW
Off-peak: All other hours of the week	$7.17	per kW

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 2
GENERAL - SMALL

Applicable to Use of Service for

Light, heat, and power for general uses for which no other service classification specifically applies and where the Customer's requirements do not exceed 10 kilowatts subject to the Common Provisions and Special Provisions of this Service Classification.

Character of Service

Of the various characteristics of service listed and more fully described in General Rule 4, the following may be designated for service by the Company under this Service Classification, subject to the limitations set forth in such Rule. Frequencies and voltages shown are approximate. All are continuous.

Standard Service

Any derivative of the standard alternating current, 3 phase, 4 wire system at 60 cycles and 120/208 volts.

Non-Standard Service

Low Tension Alternating Current - 60 cycles:

Single phase at 120/240 volts
Three phase at 265/460 volts
Three phase at 240 volts
Two phase at 120/240 or 230 or 240 volts

SERVICE CLASSIFICATION NO. 2 - Continued
GENERAL - SMALL

Rate I - General - Small

Applicability: To all Customers other than those billed under Rate II.

Delivery Charges, applicable to all Customers

Customer Charge

$33.00	per month, except as specified below
$29.59	per month for Customers furnished with unmetered service pursuant to General Rule 6.9, provided they are not billed under Special Provision D

Energy Delivery Charges

Charges applicable for the months of June, July, August, and September	19.36	cents per kWhr
Charges applicable for all other months	16.24	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 2 - Continued
GENERAL - SMALL

Rate II - General - Small - Time-of-Day

Applicability: To Customers who elect to be billed at a time-of-day rate provided the service is metered.

A Customer who elects to transfer from Rate II to Rate I will be ineligible for billing under Rate II for a period of one and one-half years from the commencement of billing under Rate I.

Delivery Charges, applicable to all Customers

Customer Charge	$33.00	per month
Energy Delivery Charges		
Charges applicable for the months of June, July, August, and September		
On peak: Monday through Friday, 8 AM to 10 PM	51.00	cents per kWhr
Off peak: All other hours of the week	1.86	cents per kWhr
Charges applicable for all other months		
On peak: Monday through Friday, 8 AM to 10 PM	25.11	cents per kWhr
Off peak: All other hours of the week	1.86	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 2 - Continued
GENERAL - SMALL

Common Provisions Applicable to Rate I and Rate II

Supply Charges

Only Full Service Customers are subject to the supply and supply-related charges and adjustments specified in General Rule 25.

Increase in Rates and Charges

The rates and charges under this Service Classification, including the Customer Charge, Additional Delivery Charges and Adjustments, and Supply and Supply-related Charges and Adjustments if applicable, are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

SERVICE CLASSIFICATION NO. 5 - Continued
ELECTRIC TRACTION SYSTEMS

Rate I - Electric Traction Systems

Applicability: To all Customers other than those billed under Rate II, Rate III or Rate IV.

Delivery Charges, applicable to all Customers

Demand Delivery Charges, per kW of maximum demand

	Low Tension Service		High Tension Service	
Charge applicable for the months of June, July, August, and September				
first 5 kW (or less)	$376.60	per month	$281.16	per month
over 5 kW	$62.81	per kW	$46.73	per kW
Charge applicable for all other months				
first 5 kW (or less)	$245.59	per month	$150.12	per month
over 5 kW	$39.99	per kW	$23.93	per kW

Minimum Charge: The minimum Delivery Demand Charge for any monthly billing period shall be the charge for 5 kW of demand.

Energy Delivery Charge

Charge applicable for all months 3.60 cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 5 - Continued
ELECTRIC TRACTION SYSTEMS

Rate II - Electric Traction Systems - Mandatory Time-of-Day - Continued

Delivery Charges, applicable to all Customers

Customer Charge $500.00 per month

Demand Delivery Charges, per kW of maximum demand for each specified time period

Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM (high/low tension service)	$7.35	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$14.85	per kW
All hours of all days (low tension service only)	$16.43	per kW
Charges applicable for all other months		
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$12.59	per kW
All hours of all days (low tension service only)	$6.54	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charges

Charges applicable for all months
All hours of all days 0.79 cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 5 - Continued
ELECTRIC TRACTION SYSTEMS

Rate III - Electric Traction Systems - Standby Service

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 who are not subject to billing under Rate IV.

Delivery Charges, applicable to all Customers

	Low Tension Service	High Tension Service
Customer Charge	$358.73 per month	
Demand Delivery Charges		
1) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$13.34 per kW	$4.53 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.3358 per kW	$0.3358 per kW
Monday through Friday, 8 AM to 10 PM	$0.8506 per kW	$0.2567 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.6695 per kW	$0.3675 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 5 - Continued
ELECTRIC TRACTION SYSTEMS

Rate IV - Electric Traction Systems - Standby Service (Large)

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 where the Contract Demand is greater than 1500 kW and/or high-tension service is supplied at 138,000 volts.

Delivery Charges, applicable to all Customers

Customer Charge	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
Charge per month	$558.26	$558.26	$546.01

Demand Delivery Charges	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
1) Contract Demand Delivery Charge, per kW of Contract Demand			
Charge applicable for all months	$8.46 per kW	$5.17 per kW	$1.73 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period			
Charges applicable for the months of June, July, August, and September			
Monday through Friday, 8 AM to 6 PM	$0.4114 per kW	$0.4403 per kW	$0.3276 per kW
Monday through Friday, 8 AM to 10 PM	$0.9784 per kW	$0.3038 per kW	N/A
Charge applicable for all other months			
Monday through Friday, 8 AM to 10 PM	$0.8877 per kW	$0.5295 per kW	$0.2505 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 5 – Continued
ELECTRIC TRACTION SYSTEMS

Common Provisions Applicable to Rate I, Rate II, Rate III, and Rate IV

Minimum Monthly Charge

Customers billed under Rate I and II will be subject to the Minimum Monthly Charge, as described in General Rule 10.10, when the Minimum Monthly Charge exceeds the monthly pure base revenue. The Contract Demand under Rate I and Rate II is determined each month and is equal to the Customer's highest registered demand in the most recent 18 months, or the highest registered demand on the Customer's account if the account has less than 18 months of demand history, provided, however, that if a Customer requests and receives a reduction in the Contract Demand (as explained in General Rule 10.10), the demand history prior to the reduction will not be considered in determining the Contract Demand for subsequent months. The Minimum Monthly Charge is not applicable to Customers billed under Rate III or Rate IV.

Supply Charges

Only Full Service Customers are subject to the supply and supply-related charges and adjustments specified in General Rule 25. Rider M may apply, as specified under that Rider.

Increase in Rates and Charges

The rates and charges under this Service Classification, including minimum charge or Minimum Monthly Charge, Additional Delivery Charges and Adjustments, and Supply and Supply-related Charges and Adjustments if applicable, are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

SERVICE CLASSIFICATION NO. 6 - Continued
PUBLIC AND PRIVATE STREET LIGHTING

Rate

Delivery Charges, applicable to all Customers

Customer Charge	$47.00	per month
Energy Delivery Charge		
Charge applicable for all months	18.64	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 8 - Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Rate I - Multiple Dwellings - Redistribution

Applicability: To all Customers other than those billed under Rate II, Rate III, Rate IV or Rate V.

Delivery Charges, applicable to all Customers

Demand Delivery Charges, per kW of maximum demand

	Low Tension Service		High Tension Service	
Charges applicable for the months of June, July, August, and September				
first 10 kW (or less)	$572.43	per month	$415.86	per month
over 10 kW	$50.57	per kW	$36.39	per kW
Charges applicable for all other months				
first 10 kW (or less)	$445.64	per month	$289.07	per month
over 10 kW	$39.07	per kW	$24.84	per kW

Minimum Charge: The minimum Delivery Demand Charge for any monthly billing period shall be the charge for 10 kW of demand.

Energy Delivery Charge, per kWhr

Charge applicable for all months for both low tension service and high tension service	1.59	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 8 - Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Rate II - Multiple Dwellings - Redistribution - Time-of-Day

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 8 - Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Rate II - Multiple Dwellings - Redistribution - Time-of-Day - Continued

Delivery Charges, applicable to all Customers

Customer Charge	$500.00	per month

Demand Delivery Charges, per kW of maximum demand for each specified time period

Charges applicable for the months of June, July, August, and September

Monday through Friday, 8 AM to 6 PM (high/low tension service)	$12.70	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$30.61	per kW
All hours of all days (low tension service only)	$24.86	per kW

Charges applicable for all other months

Monday through Friday, 8 AM to 10 PM (high/low tension service)	$23.80	per kW
All hours of all days (low tension service only)	$5.57	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charge, per kWhr

Charges applicable for all months

All hours of all days	0.79	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 8 - Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Rate III - Multiple Dwellings - Redistribution - Voluntary Time-of-Day - Continued

Delivery Charges, applicable to all Customers

Customer Charge	$50.00	per month

Demand Delivery Charges, per kW of maximum demand for each specified time period

Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM (high/low tension service)	$12.77	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$30.47	per kW
All hours of all days (low tension service only)	$28.07	per kW
Charges applicable for all other months		
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$22.52	per kW
All hours of all days (low tension service only)	$8.94	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charge, per kWhr

Charges applicable for all months		
All hours of all days	0.79	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 8 - Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Rate IV - Multiple Dwellings - Redistribution - Standby Service

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 who are not subject to billing under Rate V.

Delivery Charges, applicable to all Customers

	Low Tension Service	High Tension Service
Customer Charge	$406.97 per month	
Demand Delivery Charges		
1) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$11.11 per kW	$9.24 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.9128 per kW	$0.9128 per kW
Monday through Friday, 8 AM to 10 PM	$1.8944 per kW	$0.6009 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$1.3640 per kW	$0.8155 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 8 - Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Rate V - Multiple Dwellings - Redistribution - Standby Service (Large)

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 where: (a) the Contract Demand is greater than 1500 kW; (b) high-tension service is supplied at 138,000 volts; or (c) the Customer would otherwise take service under Rate II on an optional basis.

Delivery Charges, applicable to all Customers

Customer Charge	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
Charge per month	$1,457.40	$1,457.40	$510.12

Demand Delivery Charges	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
1) Contract Demand Delivery Charge, per kW of Contract Demand			
Charge applicable for all months	$10.23 per kW	$9.16 per kW	$2.96 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period			
Charges applicable for the months of June, July, August, and September			
Monday through Friday, 8 AM to 6 PM	$0.8787 per kW	$0.8787 per kW	$0.6591 per kW
Monday through Friday, 8 AM to 10 PM	$1.8369 per kW	$0.5835 per kW	N/A
Charge applicable for all other months			
Monday through Friday, 8 AM to 10 PM	$1.3108 per kW	$0.7828 per kW	$0.3682 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 8 – Continued
MULTIPLE DWELLINGS - REDISTRIBUTION

Common Provisions Applicable to Rate I, Rate II, Rate III, Rate IV, and Rate V

Minimum Monthly Charge

Customers billed under Rate I, II, and III will be subject to the Minimum Monthly Charge, as described in General Rule 10.10, when the Minimum Monthly Charge exceeds the monthly pure base revenue. The Contract Demand under Rate I, II, and III is determined each month and is equal to the Customer's highest registered demand in the most recent 18 months, or the highest registered demand on the Customer's account if the account has less than 18 months of demand history, provided, however, that if a Customer requests and receives a reduction in the Contract Demand (as explained in General Rule 10.10), the demand history prior to the reduction will not be considered in determining the Contract Demand for subsequent months. The Minimum Monthly Charge is not applicable to Customers billed under Rate IV or Rate V.

Supply Charges

Only Full Service Customers are subject to the supply and supply-related charges and adjustments specified in General Rule 25. Rider M may apply, as specified under that Rider.

Increase in Rates and Charges

The rates and charges under this Service Classification, including minimum charge or Minimum Monthly Charge, Additional Delivery Charges and Adjustments, and Supply and Supply-related Charges and Adjustments if applicable, are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

SERVICE CLASSIFICATION NO. 9
GENERAL - LARGE

Applicable to Use of Service for

Light, heat, and power for general uses for which no other service classification specifically applies and where the Customer's initial requirements are expected to be in excess of 10 kilowatts subject to the Common Provisions and Special Provisions of this Service Classification.

Character of Service

Of the various characteristics of service listed and more fully described in General Rule 4, the following may be designated for service by the Company under this Service Classification, subject to the limitations set forth in such Rule. Frequencies and voltages shown are approximate. All are continuous.

Standard Service

Any derivative of the standard alternating current, 3 phase, 4 wire system at 60 cycles and 120/208 volts.

Non-Standard Service

Low Tension Alternating Current - 60 cycles:

Single phase at 120/240 volts
Three phase at 265/460 volts
Three phase at 240 volts
Two phase at 120/240 or 230 or 240 volts

High Tension Alternating Current - 60 cycles:

Three phase at 2,400/4,150 volts
Three phase at 3,000 or 7,800 volts
Three phase at 6,900 volts
Three phase at 13,200 volts
Three phase at 26,400 volts
Three phase at 33,000 volts
Single phase and three phase at 2,400 volts
Three phase at 69,000 volts
Three phase at 138,000 volts

SERVICE CLASSIFICATION NO. 9 - Continued
GENERAL - LARGE

Rate I - General - Large

Applicability: To all Customers other than those billed under Rate II, Rate III, Rate IV, or Rate V.

Delivery Charges, applicable to all Customers

Demand Delivery Charges, per kW of maximum demand

	Low Tension Service		High Tension Service	
Charges applicable for the months of June, July, August, and September				
first 5 kW (or less)	$278.85	per month	$196.30	per month
over 5 kW	$39.68	per kW	$27.75	per kW
Charges applicable for all other months				
first 5 kW (or less)	$224.45	per month	$141.98	per month
over 5 kW	$31.38	per kW	$19.43	per kW

Minimum Charge: The minimum Delivery Demand Charge for any monthly billing period shall be the for 5 kW of demand.

Energy Delivery Charge, per kWhr

	Low Tension Service		High Tension Service	
Charges applicable for all months	1.99	cents per kWhr	1.85	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 9 – Continued
GENERAL - LARGE

Rate II - General - Large - Time-of-Day

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 9 - Continued
GENERAL - LARGE

Rate II - General - Large - Time-of-Day - Continued

Delivery Charges, applicable to all Customers

Customer Charge	$500.00	per month
Demand Delivery Charges, per kW of maximum demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM (high/low tension service)	$11.49	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$23.15	per kW
All hours of all days (low tension service only)	$20.91	per kW
Charges applicable for all other months		
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$18.44	per kW
All hours of all days (low tension service only)	$5.55	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charge, per kWhr

Charges applicable for all months		
All hours of all days	0.79	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 9 - Continued
GENERAL - LARGE

Rate III - General - Large - Voluntary Time-of-Day - Continued

Delivery Charges, applicable to all Customers

Customer Charge	$50.00	per month
Demand Delivery Charges, per kW of maximum demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM (high/low tension service)	$12.58	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$27.00	per kW
All hours of all days (low tension service only)	$25.82	per kW
Charges applicable for all other months		
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$17.48	per kW
All hours of all days (low tension service only)	$7.40	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charge, per kWhr		
Charges applicable for all months		
All hours of all days	0.79	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 9 - Continued
GENERAL - LARGE

Rate IV - General – Large - Standby Service

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 who are not subject to billing under Rate V.

Delivery Charges, applicable to all Customers

Customer Charge — $146.08 per month

Demand Delivery Charges

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

1) Applicable to all Customers, except for Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$12.25 per kW	$7.97 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.6669 per kW	$0.6695 per kW
Monday through Friday, 8 AM to 10 PM	$1.3468 per kW	$0.4217 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.9860 per kW	$0.5823 per kW

2) Applicable to Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$12.25 per kW	$7.97 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 10 PM	$1.3468 per kW	$0.4217 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.6266 per kW	$0.2202 per kW

SERVICE CLASSIFICATION NO. 9 - Continued
GENERAL - LARGE

Rate V - General – Large - Standby Service (Large)

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 where: (a) the Contract Demand is greater than 1500 kW and the Customer does not take service under Rider J; (b) the Contract Demand is greater than 900 kW and the Customer takes service under Rider J; (c) high-tension service is supplied at 138,000 volts; or (d) the Customer would otherwise take service under Rate II on an optional basis.

Delivery Charges, applicable to all Customers

Customer Charge	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
Charge per month	$2,023.51	$2,023.51	$545.29

Demand Delivery Charges

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

1) Applicable to all Customers, except for Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
a) Contract Demand Delivery Charge, per kW of Contract Demand			
Charge applicable for all months	$10.30 per kW	$9.11 per kW	$2.96 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period			
Charges applicable for the months of June, July, August, and September			
Monday through Friday, 8 AM to 6 PM	$0.6778 per kW	$0.7016 per kW	$0.5122 per kW
Monday through Friday, 8 AM to 10 PM	$1.4000 per kW	$0.4554 per kW	N/A
Charge applicable for all other months			
Monday through Friday, 8 AM to 10 PM	$1.0551 per kW	$0.6475 per kW	$0.2817 per kW

SERVICE CLASSIFICATION NO. 9 - Continued
GENERAL - LARGE

Rate V - General – Large - Standby Service (Large) - Continued

Delivery Charges, applicable to all Customers - Continued

Demand Delivery Charges - Continued

2) Applicable to Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$10.30 per kW	$9.11 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 10 PM	$1.4000 per kW	$0.4554 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.6840 per kW	$0.2531 per kW

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 9 – Continued
GENERAL - LARGE

Common Provisions Applicable to Rate I, Rate II, Rate III, Rate IV, and Rate V

Minimum Monthly Charge

Customers billed under Rate I, II, and III will be subject to the Minimum Monthly Charge, as described in General Rule 10.10, when the Minimum Monthly Charge exceeds the monthly pure base revenue. The Contract Demand under Rate I, II, and III is determined each month and is equal to the Customer's highest registered demand in the most recent 18 months, or the highest registered demand on the Customer's account if the account has less than 18 months of demand history, provided, however, that if a Customer requests and receives a reduction in the Contract Demand (as explained in General Rule 10.10), the demand history prior to the reduction will not be considered in determining the Contract Demand for subsequent months. For a Customer billed under Special Provision (D) of this Service Classification, the billable demand will be the basis for the Customer's Contract Demand. The Minimum Monthly Charge is not applicable to Customers billed under Rate IV or Rate V.

Supply Charges

Only Full Service Customers are subject to the supply and supply-related charges and adjustments specified in General Rule 25. Rider M may apply, as specified under that Rider.

Increase in Rates and Charges

The rates and charges under this Service Classification, including minimum charge or Minimum Monthly Charge, Additional Delivery Charges and Adjustments, and Supply and Supply-related Charges and Adjustments if applicable, are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

SERVICE CLASSIFICATION NO. 9 – Continued
GENERAL - LARGE

Special Provisions - Continued

(D) [RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 9 – Continued
GENERAL - LARGE

Special Provisions – Continued

(E) On and after April 1, 2010, a request made to the Company to install service facilities for a new or substantially renovated multiple dwelling must be accompanied by either a declaration that direct metering of each dwelling unit is intended or a copy of a submetering application filed with the Public Service Commission pursuant to 16 NYCRR Part 96.

(F) An eligible Customer's monthly bills for usage on and after July 15, 1982 will be subject to an adjustment pursuant to the requirements of Section 3, Chapter 459, 1982 N. Y. Laws.

(G) A Recharge New York ("RNY") allocation is a kW allocation made under the Recharge New York Program pursuant to Part CC of Chapter 60 of the Laws of 2011. The contract between each Customer and NYPA shall establish the term of RNY service, the RNY kW allocation, and whether all or half of the power and energy served under the RNY Program will be supplied by NYPA. Customers who receive an RNY allocation under the RNY Program will be subject to General Rule 11.

NYPA shall provide at least 30 days' prior written notice to the Company for the initial delivery of RNY power and energy to an individual Customer, changes in the kW allocation, and termination of any kW allocation, unless otherwise agreed upon by NYPA and the Company. Service will be initiated, modified, or terminated as of the Customer's first scheduled meter reading date that begins at least ten days after receipt of the notice.

Billing will be issued under this Special Provision as follows:

(1) Supply: Pursuant to the Customer's contract with NYPA, NYPA will supply either half or all of the power and energy allocated to the Customer under the RNY Program. If only half of the power and energy allocated to the Customer under the RNY Program is supplied by NYPA, the balance of the Customer's allocation and any remaining requirements not served under General Rule 11 will be supplied by: (a) the Company if the Customer is a Full Service Customer; (b) the Customer's ESCO or the Direct Customer's "Supplier," as applicable, if the Customer is a Retail Access Customer; or (c) NYPA under Rider U. Only RNY power and energy supplied by the Company will be subject to the supply and supply-related charges and adjustments specified in General Rule 25.

SERVICE CLASSIFICATION NO. 9 – Continued
GENERAL - LARGE

Special Provisions – Continued

(G) - Continued

(2) Continued

(d) Continued

The DCFC Surcharge below was developed as specified in the Commission's February 7, 2019 order in Case 18-E-0138, and shall be applicable for the 12-month period January 1, 2020 through December 31, 2020.

DCFC Surcharge……………………. $0.000116/kWhr

(e) A Customer participating in the RNY Program will receive a monthly bill credit applicable to power and energy delivered under the RNY Program, up to the Customer's RNY allocation. Such credit shall be $0.002175 per kWh commencing January 1, 2023 and continuing until such time that base rates are reset.

(3) Customers who participate in the RNY Program are exempt from the Minimum Monthly Charge (General Rule 10.10).

SERVICE CLASSIFICATION NO. 9 – Continued
GENERAL - LARGE

Special Provisions – Continued

(H) - Continued

(3) Restrictions as to Eligibility

Service will not be provided under this Special Provision if: (a) the Customer is served under Rider J, Rider R, or Rider Y of this SC; (b) service is furnished solely or predominantly for telephone booths, warning lights, bus stop shelters, signboards, cable television and telecommunication local distribution facilities, or similar structures or locations; or (c) service is provided for construction purposes or for activities of a temporary nature (as described in General Rule 5.2.7). Customers who discontinue service under this Rider to commence service under Rider J will not be eligible thereafter to receive service under this Special Provision.

(4) Reductions on Electric Delivery Charges

(a) If the Customer is served under General Rule 11 for any requirements, the Customer will first be served under those programs; provided, however, that the Customer will first be served under this Special Provision for Delivery Service if the Customer elects to receive Delivery Service under this Special Provision for RNY load pursuant to Special Provision (G).

(b) The Customer will receive a reduction on SC 9 delivery charges for each monthly billing period based on the Percentage Rate Reduction specified in (c) as follows:

For Existing Rate I, II, and III Customers, the Percentage Rate Reduction will be applied to the Demand Delivery Charges and Energy Delivery Charges as determined for the billing period associated with the monthly registered demand and monthly registered kilowatthours in excess of the kW and kWhr Baseline Billing Determinants.

For Existing Rate IV and Rate V Customers, the Percentage Rate Reduction will be applied to (i) the Customer Charge, Contract Demand Delivery Charges, and As-used Daily Demand Delivery Charges as determined for the billing period multiplied by (ii) the ratio of the current Contract Demand in excess of the Baseline Billing Determinant to the current Contract Demand, provided that ratio shall never exceed 1.

For New Rate I, II, and III Customers, the Percentage Rate Reduction will be applied to the Demand Delivery Charges and Energy Delivery Charges as determined for the billing period associated with the monthly registered demand and monthly registered kilowatthours. For New Rate IV and Rate V Customers, the Percentage Rate Reduction will be applied to the Customer Charge, Contract Demand Delivery Charges, and As-used Daily Demand Delivery Charges as determined for the billing period.

The Revenue Decoupling Mechanism will not be applicable to load served under this Special Provision. No rate reductions will be applied to other delivery charges, including but not limited to, the Billing and Payment Processing Charge, and other delivery charges and adjustments specified in General Rule 26.

SERVICE CLASSIFICATION NO. 11 - Continued
BUY-BACK SERVICE

Charges to be Paid by the Customer

Customer Charge and Delivery Service Contract Demand Charge

The Customer will be required to pay a Customer Charge (per month) and a Delivery Service Contract Demand Charge (per kW per month of the Contract Demand) based on the SC that would otherwise be applicable to the Customer if the Customer were taking the Company's delivery service; provided, however, that if service is taken by the Customer under both this SC and another SC through the same service connection: (i) the Customer Charge will be waived under this SC; and (ii) the contract demand charges under this SC shall apply only to the contract demand in excess of the contract demand billed under Standby Service rates or the contract demand in excess of the as-used demand billed under another rate.

If the Contract Demand under this SC is 1500 kW or less

		Delivery Service Contract Demand Charge (per kW of Contract Demand)	
	Customer Charge (per month)	High Tension Service below 138 kV	Low Tension Service
SC 5	$358.73	$4.53	$13.34
SC 8	$406.97	$9.24	$11.11
SC 9	$146.08	$7.97	$12.25
SC 12	$207.12	$8.02	$10.05

If the Contract Demand under this SC is greater than 1500 kW

		Delivery Service Contract Demand Charge (per kW of Contract Demand)	
	Customer Charge (per month)	High Tension Service below 138 kV	Low Tension Service
SC 5	$558.26	$5.17	$8.46
SC 8	$1,457.40	$9.16	$10.23
SC 9	$2,023.51	$9.11	$10.30
SC 12	$819.39	$8.30	$8.69
SC 13	$4,146.27	$9.06	N/A

If the Customer takes high tension service at 138 kV, regardless of the Contract Demand kW

		Delivery Service Contract Demand Charge (per kW of Contract Demand)
	Customer Charge (per month)	High Tension Service at 138 kV
SC 5	$546.01	$1.73
SC 8	$510.12	$2.96
SC 9	$545.29	$2.96
SC 12	$478.26	$1.90
SC 13	$3,426.76	$3.50

A Customer who would otherwise receive service under a non-demand billed SC will be considered to have requirements in excess of 10 kilowatts and will be subject to the Customer Charge and the Delivery Service Contract Demand Charge shown for Customers who would be subject to SC No. 5, 8, 9, or 12, as appropriate. The contract demand charge under this SC shall apply only to the contract demand in excess of 10 kW for a Customer billed under a non-demand SC.

SERVICE CLASSIFICATION NO. 11
BUY-BACK SERVICE

Common Provisions

Interconnection and Operation

The interconnection and operation requirements applicable for Customers served under this Service Classification are described in General Rule 8.4.

SERVICE CLASSIFICATION NO. 11
BUY-BACK SERVICE

Common Provisions - Continued

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 11 - Continued
BUY-BACK SERVICE

Common Provisions - Continued

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 11
BUY-BACK SERVICE

Common Provisions - Continued

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 11
BUY-BACK SERVICE

Common Provisions - Continued

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 11
BUY-BACK SERVICE

Common Provisions - Continued

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 11 - Continued
BUY-BACK SERVICE

Common Provisions - Continued

Determination of Demand

The contract demands for high-tension service and low-tension service for the purpose of this Service Classification shall be the contract demands as specified in the Customer's request for service hereunder (expressed in kW), unless and until a higher maximum demand is created by the Customer, in which case such higher maximum demand shall become the contract demand for that month and thereafter unless and until exceeded by a still higher maximum demand, which in turn shall likewise be subject to the foregoing conditions, provided, however, that if a Customer requests and receives a reduction in the contract demand (as explained in General Rule 10.10), the demand history prior to the reduction will not be considered in determining the contract demand for subsequent months.

If the monthly maximum demand exceeds the contract demand by ten percent or less, a surcharge equal to twelve times the monthly contract demand rate for the excess in demand will apply to the monthly bill. If the monthly maximum demand exceeds the contract demand by more than ten percent, a surcharge equal to twenty-four times the monthly contract demand rate for the excess in demand will apply to the monthly bill.

SC 11 must be contracted for separately and will be metered separately from Standby Service (as defined under General Rule 20).

SERVICE CLASSIFICATION NO. 11 - Continued
BUY-BACK SERVICE

Special Provisions - Continued

(G) A seller under a sales agreement with Con Edison as of April 1, 2000, depending on the seller's option, such agreement shall be modified to include provisions that are either consistent with direct sales to the NYISO or that accommodate scheduling by the Company with the NYISO. In the case of direct sales to the NYISO, such contract provisions shall include the requirement that the energy seller report to the Company each day as to the hourly amounts of energy produced at seller's facility and delivered to the NYISO and the hourly amounts that would otherwise have been delivered to the Company pursuant to the sales agreement. In the case of deliveries to the Company based on schedules, such contract provisions shall include the seller's agreement to assume sole responsibility for any penalties or obligations imposed on either the seller or the Company as a result of the seller's failure to deliver energy in accordance with its schedules or at the direction of the NYISO. All other existing contractual obligations and related costs will remain the responsibility of the party who was responsible for such obligations and related costs during the pre-NYISO period.

After making an election as to whether to sell directly to the NYISO under the Wholesale Distribution Service or to the Company under this SC, an energy seller will be ineligible to change its election for one year from the date of any election. An energy seller that elects to sell energy to the Company will be prohibited from selling or otherwise diverting any portion of its plant's output to any third party, including selling directly to the NYISO, unless expressly provided for in its sales agreement with the Company. An energy seller that elects to discontinue selling energy under this Service Classification will be ineligible to resume sales under this Service Classification for one year from the date of such election.

An initial election shall be made by an energy seller no later than April 1, 2000, if such seller is selling energy at or based upon the SC 11 Buy-Back energy rates as of April 1, 2000. A seller commencing energy sales at a later date shall make an initial election prior to commencing service under a sales agreement.

Customers that elect to sell the energy output of their generators to the NYISO are subject to the Interconnection and Operation provisions of this SC unless their interconnection is subject to FERC jurisdiction.

SERVICE CLASSIFICATION NO. 11
BUY-BACK SERVICE

Special Provisions – Continued

(H) A capacity seller with a generating facility sized at 5 megawatts or less may elect to sell its capacity to the Company and receive payments based upon the NYISO unforced capacity monthly market price applicable to such capacity.

By taking service hereunder, the Customer is responsible to meet all of the requirements applicable to installed capacity established by the NYISO, as well as assumption of the sole responsibility for any penalties, including payments for capacity deficiencies, imposed by the NYISO on the seller or on the Company as a result of the seller's failure to satisfy all such requirements.

After making an election as to whether to sell directly to the NYISO under the Wholesale Distribution Service or to the Company under this SC, a capacity seller will be ineligible to change its election for one year from the date of any election. A capacity seller that elects to discontinue selling capacity under this Service Classification will be ineligible to resume sales under this Service Classification for one year from the date of such election.

(I) Optional Bill Credit for Export-only Customers

An Optional Bill Credit ("Credit") is available to Customers who export only (i.e., they do not take service under another Service Classification through the same service connection) and who have not opted to receive compensation under the Value Stack Tariff as specified in Rider R. The Credit is based on the performance of the Customer's generation facility during a previous Measurement Period for which interval data was available from an Output Meter (as defined in General Rule 2). To be eligible for the Credit: (a) the Customer must arrange to furnish and install the Output Meter at Customer expense; and (b) the generation facility: (i) must be designed to meet the same local air quality criteria required of Customers With Targeted Exemptions, as specified in General Rule 20.3.4, if the generation facility is new or expanding and located in one of the zip codes listed in that General Rule, provided, however, that eligibility for the Credit will not be affected due to actual emissions exceeding design, and (ii) must be designed to have maximum NOx emissions of 1.6 lbs/MWh if the Customer was served under SC 11 as of January 1, 2017, or is located in a zip code not specified in General Rule 20.3.4. Customers seeking the Credit may participate in the Distribution Load Relief Program, but not the Commercial System Relief Program ("CSRP"), under Rider T.

A Customer seeking a Credit must request such Credit by October 10 of each year for which the credit is sought. The Credit for any Measurement Period will be equal to the product of: (a) the Performance Adjustment and (b) the Payment Rate. The Credit will be applied to the Customer's successive 12 monthly bills commencing in November until the following October.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate I - Multiple Dwelling Space Heating

Applicability: To all Customers other than those billed under Rate II, Rate III, Rate IV, and Rate V.

Delivery Charges, applicable to all Customers billed for both energy and demand

Demand Delivery Charges, per kW of maximum demand

	Low Tension Service		High Tension Service	
Charges applicable for the months of June, July, August, and September				
first 5 kW (or less)	$313.13	per month	$238.90	per month
over 5 kW	$54.45	per kW	$40.69	per kW
Charges applicable for all other months				
first 5 kW (or less)	$184.08	per month	$110.10	per month
over 5 kW	$30.53	per kW	$16.79	per kW

Minimum Charge: Where the Customer is billed for energy and demand, the minimum Delivery Demand Charge for any monthly billing period shall be the charge for 5 kW of demand.

Energy Delivery Charge, per kWhr

Charge applicable for all months for both low tension service and high tension service 1.63 cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate I - Multiple Dwelling Space Heating - Continued

Delivery Charges, applicable to all Customers billed for energy only

Energy Delivery Charge

Charges applicable for the months of June, July, August, and September

first 10 kWhr (or less)	$18.45	
over 10 kWhr	17.89	cents per kWhr

Charges applicable for all other months

first 10 kWhr (or less)	$18.23	
over 10 kWhr	16.14	cents per kWhr

Minimum Charge: Where the Customer is billed for energy only, the minimum charge for energy for any monthly billing period shall be the charge for 10 kWhr.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate II - Multiple Dwelling Space Heating - Time-of-Day

Applicability:

[RESERVED FOR FUTURE USE]

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate II - Multiple Dwelling Space Heating - Time-of-Day

Delivery Charges, applicable to all Customers

Customer Charge $500.00 per month

Demand Delivery Charges, per kW of maximum demand for each specified time period

Charges applicable for the months of June, July, August, and September

Monday through Friday, 8 AM to 6 PM (high/low tension service)	$12.22	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$31.42	per kW
All hours of all days (low tension service only)	$18.61	per kW

Charges applicable for all other months

Monday through Friday, 8 AM to 10 PM (high/low tension service)	$20.07	per kW
All hours of all days (low tension service only)	$12.65	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charge, per kWhr

Charges applicable for all months

All hours of all days 0.79 cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate III - Multiple Dwelling Space Heating - Voluntary Time-of-Day - Continued

Delivery Charges, applicable to all Customers billed for both energy and demand

Customer Charge $50.00 per month

Demand Delivery Charges, per kW of maximum demand for each specified time period

Charges applicable for the months of June, July, August, and September

Monday through Friday, 8 AM to 6 PM (high/low tension service)	$10.99	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$25.97	per kW
All hours of all days (low tension service only)	$26.72	per kW

Charges applicable for all other months

Monday through Friday, 8 AM to 10 PM (high/low tension service)	$11.47	per kW
All hours of all days (low tension service only)	$20.34	per kW

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Energy Delivery Charge, per kWhr

Charges applicable for all months
All hours of all days 0.79 cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate III - Multiple Dwelling Space Heating - Voluntary Time-of-Day - Continued

Delivery Charges, applicable to all Customers billed for energy only

Customer Charge	$33.00	per month
Energy Delivery Charges		
Charges applicable for the months of June, July, August, and September		
On peak: Monday through Friday, 8 AM to 10 PM	51.00	cents per kWhr
Off peak: All other hours of the week	1.86	cents per kWhr
Charges applicable for all other months		
On peak: Monday through Friday, 8 AM to 10 PM	25.11	cents per kWhr
Off peak: All other hours of the week	1.86	cents per kWhr

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate IV - Multiple Dwelling Space Heating - Standby Service

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 who are not subject to billing under Rate V.

Delivery Charges, applicable to all Customers

Customer Charge — $207.12 per month

Demand Delivery Charges	Low Tension Service	High Tension Service
1) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$10.05 per kW	$8.02 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.6525 per kW	$0.6525 per kW
Monday through Friday, 8 AM to 10 PM	$1.8744 per kW	$0.6427 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$1.2843 per kW	$0.6069 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Rate V - Multiple Dwelling Space Heating - Standby Service (Large)

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 where: (a) the Contract Demand is greater than 1500 kW; (b) high-tension service is supplied at 138,000 volts; or (C) the Customer would otherwise take service under Rate II on an optional basis.

Delivery Charges, applicable to all Customers

Customer Charge

	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
Charge per month	$819.39	$819.39	$478.26

Demand Delivery Charges

	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
1) Contract Demand Delivery Charge, per kW of Contract Demand			
Charge applicable for all months	$8.69 per kW	$8.30 per kW	$1.90 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period			
Charges applicable for the months of June, July, August, and September			
Monday through Friday, 8 AM to 6 PM	$0.6500 per kW	$0.6500 per kW	$0.4874 per kW
Monday through Friday, 8 AM to 10 PM	$2.0687 per kW	$0.7106 per kW	N/A
Charge applicable for all other months			
Monday through Friday, 8 AM to 10 PM	$1.5044 per kW	$0.6842 per kW	$0.2147 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Common Provisions Applicable to Rate I, Rate II, Rate III, Rate IV, and Rate V

General Rules

For general rules, regulations, terms and conditions under which service will be supplied, see General Rules to this Rate Schedule. Riders that may be applied to this Service Classification are specified under General Rule 24.

Terms of Payment

Net cash on presentation of bill, subject to late payment charge in accordance with provisions of General Rule 12.1.

Applications for Service

For forms of application under this Service Classification, see the Application Forms section of the General Rules.

Term

One year from the date of installation of service hereunder; terminable thereafter by the Customer upon 30 days' prior notice in writing and by the Company in accordance with law or the provisions of this Rate Schedule.

SERVICE CLASSIFICATION NO. 12 - Continued
MULTIPLE DWELLING SPACE HEATING

Special Provisions – Continued

(D) By order of the Public Service Commission in Case 91-E-0462, no nursing home in which the entire space heating requirements are supplied by the use of electricity purchased from the Company shall be eligible to receive service under this Service Classification on or after July 1, 1992.

(E) Whenever a Customer's maximum demand under Rate I or Rate III of this Service Classification exceeds 10 kilowatts in two consecutive months, the Customer's use thereafter will be billed under both energy and demand rates. Whenever a Customer’s maximum demand under Rate I or Rate III of this Service Classification shall not have exceeded 5 kilowatts for a period of 12 consecutive months, the Customer’s use thereafter will be billed under energy only rates.

SERVICE CLASSIFICATION NO. 13 - Continued
BULK POWER - HOUSING DEVELOPMENTS

Rate I - Bulk Power - Housing Developments -Continued

Delivery Charges, applicable to all Customers

Customer Charge $500.00 per month

Demand Delivery Charges, per kW of maximum demand for each specified time period

The demand charge for each time period will be determined by multiplying the maximum demand for the respective time period by the rate applicable to the demand for that time period. The total demand charge will be the sum of the charges for each of the time periods.

Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$8.21	per kW
Monday through Friday, 8 AM to 10 PM	$18.38	per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$11.31	per kW

Minimum Charge: The minimum Delivery Demand Charge for any monthly billing period shall be the charge for 8,500 kilowatts of demand during the period Monday through Friday 8:00 AM to 10:00 PM.

Energy Delivery Charge, per kWhr

Charges applicable for all months		
All hours of all days	0.79	cents per kWhr

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

Minimum Monthly Charge

Customers billed under Rate I are subject to the Minimum Monthly Charge, as described in General Rule 10.10, when the Minimum Monthly Charge exceeds the monthly pure base revenue. The Contract Demand is determined each month and is equal to the Customer's highest registered demand in the most recent 18 months, or the highest registered demand on the Customer's account if the account has less than 18 months of demand history, provided, however, that if a Customer requests and receives a reduction in the Contract Demand (as explained in General Rule 10.10), the demand history prior to the reduction will not be considered in determining the Contract Demand for subsequent months.

SERVICE CLASSIFICATION NO. 13 - Continued
BULK POWER - HOUSING DEVELOPMENTS

Rate II - Bulk Power - Housing Development – Standby Service

Applicability: To Customers billed under Standby Service rates pursuant to General Rule 20 where the Contract Demand exceeds 1,500 kW.

Delivery Charges, applicable to all Customers

Customer Charge

	High Tension Service below 138 kV	High Tension Service at 138 kV
Charge per month	$4,146.27	$3,426.76

Demand Delivery Charges

	High Tension Service below 138 kV	High Tension Service at 138 kV
1) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$9.06 per kW	$3.50 per kW
2) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.4963 per kW	$0.3722 per kW
Monday through Friday, 8 AM to 10 PM	$0.3782 per kW	N/A
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.4515 per kW	$0.1893 per kW

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

Reactive Power Demand Charge, applicable as specified in General Rule 10.11.

Additional Delivery Charges and Adjustments, as specified in General Rule 26.

SERVICE CLASSIFICATION NO. 13 - Continued
BULK POWER - HOUSING DEVELOPMENTS

Common Provisions Applicable to Rate I and Rate II

Supply Charges

Only Full Service Customers are subject to the supply and supply-related charges and adjustments specified in General Rule 25. Rider M may apply, as specified under that Rider.

Increase in Rates and Charges

The rates and charges under this Service Classification, including minimum charge or Minimum Monthly Charge, Additional Delivery Charges and Adjustments, and Supply and Supply-related Charges and Adjustments if applicable, are increased by the applicable percentage as explained in General Rule 30 and shown on the related Statement.

General Rules

For general rules, regulations, terms and conditions under which service will be supplied, see General Rules to this Rate Schedule. Riders that may be applied to this Service Classification are specified under General Rule 24.

Terms of Payment

Net cash on presentation of bill, subject to late payment charge in accordance with provisions of General Rule 12.1.

Applications for Service

For forms of application under this Service Classification, see the Application Forms section of the General Rules.

Term

Ten years from the date of installation of service hereunder; terminable thereafter by the Customer upon one years' prior notice in writing, and by the Company in accordance with law or the provisions of this Rate Schedule.

P.S.C. No. 12 – Electricity

TARIFF LEAVES

PASNY DELIVERY SERVICE

Rate I

Applicability: To PASNY Customers who are not served under Rate II, Rate III, or Rate IV.

Applicable to demand-billed service, street lighting in The City of New York, and The City of New York calculated demand accounts

	Low Tension Service	High Tension Service
Demand Delivery Charge (per kW per month of the maximum demand)	$37.97	$25.72

Reactive Power Demand Charge, applicable as specified under the Common Charges of this Rate Schedule.

Applicable to non-demand-billed service and Westchester street lighting

Energy Delivery Charge 28.15 cents per kWhr per month

PASNY DELIVERY SERVICE

Rate I - Continued

Facilities and Service Connection Charges - for street lighting and fire alarm or signal systems

A) Furnishing and Maintaining Control Equipment Charge

Delivery service for public street lighting in the County of Westchester is subject to the following additional charge and is available subject to the limitations provided in Special Provision 3(C) hereof.

For each point of service termination, as defined in Special Provision 3(B) hereof, where the Company supplies controlled period service from its circuits. . . . . $7.32 per calendar month

B) Facilities Charge

Delivery service for public street lighting in The City of New York is subject to the following additional charge:

For each point of service termination, as defined in Special Provision 3(B) hereof, where the Company's electrical system is connected to the City's lighting unit or to a lighting circuit owned by the City . . . . $17.11 per calendar month

C) Service Connection and Gong or Signal Circuit Charge

Delivery service for the operation of interior fire alarm or signal systems not connected to the metered supply for the building and where separate service is supplied, is subject to the following charges:

1) For service connection. $185.74

2) For each gong or signal circuit or combination of gong or signal circuits in which there is a continuous flow of current of not over 125 milliamperes, the voltage of the supply being approximately 120 volts or the equivalent (taken as 15 volt-amperes) at other supply voltages . . . . $12.76 per calendar month

3) For each additional 125 milliamperes (or equivalent) of continuous flow, or fraction thereof, an additional charge of . . . . $12.76 per calendar month

PASNY DELIVERY SERVICE

Rate II - Time-of-Day

Applicability:

(1) To PASNY Customers who were billed under Rate II as of February 20, 2012;
(2) To any PASNY Customer whose monthly maximum demand exceeds 1,500 kW in any annual period ending September 30;
(3) To any new PASNY Customer whose monthly maximum demand in the Company's estimate will exceed 1,500 kW during the first year of service; and
(4) To successors of PASNY Customers referred to in (1), (2) and (3) above; if eligible for PASNY delivery service;

provided the PASNY Customer is not subject to billing under Rate IV.

For PASNY Customers subject to Rate II pursuant to (2) above, billing under Rate II shall commence when the PASNY Customer's entire usage is subsequent to December 31 of the annual period ending September 30 in which the PASNY Customer becomes subject to Rate II.

Rate II is not applicable to traction and substation accounts.

A Rate II Customer shall be transferred to and billed under Rate I in the first billing period that commences after the Customer's monthly maximum demand does not exceed 900 kW for 12 consecutive months.

Demand Delivery Charges, per kW per month of the maximum demand

Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM (high/low tension service)	$10.19	per kW
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$29.99	per kW
All hours of all days (low tension service only)	$27.67	per kW
Charges applicable for all other months		
Monday through Friday, 8 AM to 10 PM (high/low tension service)	$18.18	per kW
All hours of all days (low tension service only)	$6.51	per kW

The total demand delivery charge for each billing period, excluding the Reactive Power Demand Charge, shall be the sum of the charges for each applicable time period, each charge determined by multiplying the maximum demand for the respective time period by the rate applicable for that time period.

Reactive Power Demand Charge, applicable as specified under the Common Charges of this Rate Schedule.

PASNY DELIVERY SERVICE

Rate III - Standby Service

Applicability: To PASNY Customers billed under Standby Service rates, provided the PASNY customer is not subject to billing under Rate IV.

Customer Charge $281.57 per month

Demand Delivery Charges

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used

1) Applicable to all Customers, except for Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$12.52 per kW	$9.64 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 6 PM	$0.7582 per kW	$0.7667 per kW
Monday through Friday, 8 AM to 10 PM	$1.8538 per kW	$0.5963 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$1.2107 per kW	$0.7563 per kW

2) Applicable to Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	$12.52 per kW	$9.64 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 10 PM	$1.8538 per kW	$0.5963 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	$0.7278 per kW	$0.2651 per kW

Reactive Power Demand Charge, applicable as specified under the Common Charges of this Rate Schedule.

PASNY DELIVERY SERVICE

Rate IV - Standby Service (Large)

Applicability: To PASNY Customers billed under Standby Service rates where:
(a) the Contract Demand is greater than 1500 kW, or (b) high-tension service is supplied at 138,000 volts.

Rate IV is not applicable to traction and substation accounts.

Customer Charge	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
Charge per month	$807.50	$807.50	$89.40

Demand Delivery Charges

For each day in the billing period for which As-used Daily Demand Delivery Charges are to be determined, the As-used Daily Demand Delivery Charge for each time period shall be determined by multiplying the daily maximum demand during the time period by the per-kilowatt As-used Daily Demand Delivery Charge applicable to that time period. As-used Daily Demand Delivery Charges, as billed, are equal to the sum of the As-used Daily Demand Delivery Charges for the time periods.

1) **Applicable to all Customers, except for Station Use by Wholesale Generators:**

	Low Tension Service	High Tension Service below 138 kV	High Tension Service at 138 kV
a) Contract Demand Delivery Charge, per kW of Contract Demand			
Charge applicable for all months	$12.41 per kW	$8.33 per kW	$2.64 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period			
Charges applicable for the months of June, July, August, and September			
Monday through Friday, 8 AM to 6 PM	$0.6018 per kW	$0.6276 per kW	$0.4608 per kW
Monday through Friday, 8 AM to 10 PM	$1.5597 per kW	$0.5033 per kW	N/A
Charge applicable for all other months			
Monday through Friday, 8 AM to 10 PM	$0.8486 per kW	$0.5641 per kW	$0.2688 per kW

PASNY DELIVERY SERVICE

Rate IV - Standby Service (Large) - Continued

Demand Delivery Charges - Continued

2) Applicable to Station Use by Wholesale Generators:

	Low Tension Service	High Tension Service
a) Contract Demand Delivery Charge, per kW of Contract Demand		
Charge applicable for all months	\$12.41 per kW	\$8.33 per kW
b) As-used Daily Demand Delivery Charges, per kW of Daily Peak Demand for each specified time period		
Charges applicable for the months of June, July, August, and September		
Monday through Friday, 8 AM to 10 PM	\$1.5597 per kW	\$0.5033 per kW
Charge applicable for all other months		
Monday through Friday, 8 AM to 10 PM	\$0.5024 per kW	\$0.1924 per kW

Reactive Power Demand Charge, applicable as specified under the Common Charges of this Rate Schedule.

PASNY DELIVERY SERVICE

Common Charges and Adjustments

Reactive Power Demand Charge

The Reactive Power Demand Charge specified in General Rule 10.11 of the Schedule for Electricity is applicable to service under this Rate Schedule, except as modified below:

"Customers" in General Rule 10.11 means "PASNY Customers" served under Rate I, II, III, and IV of this Rate Schedule.

The commencement of Reactive Power Demand Charges to PASNY Customers served under Rate I and Rate III will be in accordance with section (2)(a) of General Rule 10.11. The commencement of Reactive Power Demand Charges to PASNY Customers served under Rate II and Rate IV will be in accordance with section (2)(b) of General Rule 10.11.

The Charge per kVar is:
$2.38 per kVar, applicable to Customers specified in paragraph (1)(a), (b), (c), and (d) of General Rule 10.11; and $2.14 per kVar, applicable to Customers specified in paragraph (1)(e) of General Rule 10.11.

These charges are in lieu of charges specified in General Rule 10.11(4) of the Schedule for Electricity.

PASNY DELIVERY SERVICE

General Provisions

Determination of Billable Demand

An Interval Meter is required for service under Rate II, Rate III, and Rate IV. For service under Rate III and Rate IV, such Interval Meter may include equipment either to prevent reverse meter registration or to separately measure electricity generated by the PASNY Customer and electricity delivered by the Company.

With respect to the determination of demand for public buildings of The City of New York and subject to Special Provision 5 hereof, the maximum demand used to compute the bill to PASNY shall be the total of the recorded and calculated demands for all such public buildings receiving delivery service under this Rate Schedule. Where a demand meter is not required in premises served by the Company, the determination of the monthly maximum demand for those premises shall be calculated by dividing the total energy consumed in kilowatthours by 180, except that when such calculated demand exceeds 10 kilowatts, a billing demand of 10 kilowatts shall be used.

Whenever a PASNY Customer's maximum demand under Rate I exceeds 10 kilowatts in two consecutive months, the PASNY Customer will be billed under demand billed service rates. Whenever a PASNY Customer's maximum demand for a period of 12 consecutive months shall not have exceeded 5 kilowatts under Rate I, the Customer will thereafter be billed for non-demand billed service rates.

PASNY DELIVERY SERVICE

General Provisions - Continued

Meters with Communications Capabilities

(1) The Company will provide and maintain the communications service for: (a) Customers served under Rate II; (b) Customers subject to Reactive Power Demand Charges; (c) Customers served under Rate IV who would otherwise be subject to Rate II if they did not have on-site generation; and (d) Customers served by Interval Meters installed under the Company's AMI program.

(2) PASNY will arrange for the provision and maintenance of the communications service unless the Company is required to provide and maintain it as specified in paragraph (1) above. If communication is by telephone line, PASNY will arrange for a dedicated telephone line. If the telephone line is not operational for any reason when the Company attempts to read the meter, the charge specified in General Rule 16.4 of the Schedule for Electricity will be assessed.

PASNY DELIVERY SERVICE

General Provisions - Continued

Standby Service and Standby Service Rates

PASNY Customers who take Standby Service or are billed under Standby Service rates are subject to all terms and conditions of General Rule 20 of the Schedule for Electricity, except as modified below:

“Customer” in General Rule 20 means “PASNY Customer” under this Rate Schedule unless expressly stated otherwise below.

“Standby Service rates,” as defined in General Rule 20.1, means Rate III or Rate IV of this Rate Schedule.

Contract Demand, as specified in General Rule 20.4, is established for the account of a PASNY Customer either by PASNY or the Company. The rules related to “Customers” who establish and revise their Contract Demand are applicable to “PASNY” under this Rate Schedule. Where PASNY accepts a Company-set Contract Demand, no penalties shall apply if that Contract Demand is exceeded.

Paragraph 2 of General Rule 20.4.5 is replaced by the following: Billing will be issued to PASNY under Standby Service rates, as modified below: (a) There will be an additional Customer Charge of $50.00 per billing period, exclusive of the Increase in Rate and Charges, to cover incremental billing and administrative costs associated with providing service under this provision. (b) The daily maximum demand used in determining As-used Daily Delivery Service Demand Charges will be the highest net integrated demand, i.e., the difference between the PASNY Customer’s low-tension registered demand and the demand registered on the high-tension meter measuring the generator’s output (adjusted for losses). (c) The monthly maximum demand used in determining Contract Demand exceedances under section (A) of General Rule 20.4.3 will be the low-tension maximum demand. The Company will not provide kilowatthour credits for the generator’s output.

PASNY DELIVERY SERVICE

General Provisions - Continued

Standby Service and Standby Service Rates - Continued

General Rule 20.4.6 is amended as follows:

The following text replaces General Rule 20.4.6: The output of the generating facility must supply the Standby Service accounts of a single PASNY Customer ("Single Party Offset"). Alternatively, the output of the generating facility must supply the Standby Service accounts of two or more PASNY Customers ("Multi-party Offset"), provided all of the following conditions are met: (i) the PASNY Customer that owns or operates the generating facility (the "Sponsor") must be the PASNY Customer on at least one of the Standby Service accounts, and that account must have a Contract Demand equal to 10 percent or more of the nameplate rating of the generating facility; (ii) the Standby Service accounts supplied by the output of the Sponsor's generating facility ("Recipient Accounts") shall have no other source of generation located on the premises, except as permitted under General Rule 8.2 of the Schedule for Electricity; (iii) the Sponsor and/or its representative will be responsible for coordinating the interconnection and operation of the generating facility with the Company; and (iv) at the time of application under the Multi-party Offset, the Sponsor or its representative must submit a signed PASNY Multi-Party Offset Percentage Allocation Form, available on the Company's website. Billing will be issued to PASNY for the Standby Service accounts designated by PASNY or the Sponsor and for the account associated with export of the generating facility.

In General Rule 20.4.6(a)(6), the Output Meter will be furnished and installed at PASNY expense.

The following text replaces General Rule 20.4.6(c): Accounts Supplied by the Generating Facility's Output: Each account supplied by the generator's output must be eligible for billing under Rate III or Rate IV of this Rate Schedule and must be billed under the Standby Service rate applicable to that individual account. No account served under General Rule 20.4.6 may be served under any of the economic development programs specified in General Rule 11. At least one of the Standby Service accounts must be connected to the Company's low-tension distribution system.

Paragraph 2 of General Rule 20.4.7 is replaced by the following: Billing will be issued to PASNY under Standby Service rates, as modified below: (a) There will be an additional Customer Charge of $50.00 per billing period, exclusive of the Increase in Rate and Charges, to cover incremental billing and administrative costs associated with providing service under this provision; and (b) any excess kW export from the service connection to which the PASNY Customer's generating facility is connected will be netted against the usage on the PASNY Customer's other service connections on an interval metered basis. The Company will not provide kilowatthour credits for the generator's output.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments

Definitions, applicable to Special Provision Adjustments only:

"Pure Base Revenue" under this Rate Schedule means revenue attributable to charges under Rates I, II, III and IV, before application of the Increase in Rates and Charges, and excludes Additional Delivery Charges and Adjustments, the Interconnection Charge, the effect of Metering Credits for Metering Services, and Reactive Power Demand Charges. If the Minimum Monthly Charge would apply under Rate I or Rate II, then revenues attributable to charges under Rate I or Rate II means revenue attributable to the Minimum Monthly Charge before application of the Increase in Rates and Charges.

"Delivery Revenues" under this Rate Schedule means Pure Base Revenue under this Rate Schedule plus the effect of Metering Credits for Metering Services, if any, before application of the Increase in Rates and Charges.

(A) Billing Adjustments

The rates and charges for the delivery of power and associated energy to PASNY Customers shall be subject to a charge representing PASNY's share of the cost of the savings passed on to eligible Customers in accordance with Section 3, Chapter 459, 1982 N. Y. Laws.

(B) System Benefits Charge

The System Benefits Charge, and any surcharge thereto authorized by the Commission, is applicable to all PASNY Customers who utilize the Company's distribution system and recovers costs required to be spent on necessary environmental and other public policy programs. The System Benefits Charge for each rate is shown below.

The System Benefits Charge is currently $0.00 for Rate I, Rate II, Rate III, and Rate IV.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(C) [RESERVED FOR FUTURE USE]

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(D) Revenue Decoupling Mechanism ("RDM") Adjustment - Continued

(3) Allowed Pure Base Revenue

Allowed Pure Base Revenue under this Rate Schedule is as follows:

Jan. – Dec. 2022	$674,610,000
Jan – Dec. 2023*	To be determined

*Revenue targets for each rate year thereafter will continue at these amounts unless and until changed.

Annual Allowed Pure Base Revenue will be revised whenever there is a change in delivery rates. Furthermore, if, for any reason, a Service Classification of the Company's Schedule for Electricity no longer has existing customers, the Allowed Pure Base Revenue for that Service Classification will be reallocated to this Rate Schedule and to other Service Classifications of the Schedule for Electricity to provide for equitable treatment of revenue deficiencies from the discontinued class. In the event Allowed Pure Base Revenue is reallocated, the Company will notify the Department of Public Service Commission Staff of the revised Allowed Pure Base Revenue amount(s). The Company will be allowed to defer collection of any revenue shortfall or refund of any revenue surplus that results from a delay in the approval of a reallocation of Allowed Pure Base Revenue.

(4) Low Income Program Costs

The Company will adjust the RDM amounts to be collected over each six-month RDM collection/refund period to reflect each class's share of the difference between actual Low Income Program costs and the amount of these costs included in rates (i.e., $118.82 million annually).

Any Low Income Program costs required to be collected or refunded will be passed through the RDM Adjustment applicable under this Rate Schedule and the RDM Adjustment applicable under the Company's Schedule for Electricity. The amount to be collected or refunded under this Rate Schedule will be equal to the total amount to be collected or refunded times the ratio of forecasted Rate Year Delivery Revenues under this Rate Schedule to the combined total of forecasted Rate Year Delivery Revenues under this Rate Schedule and the Schedule for Electricity for the Rate Year in effect at the commencement of the six-month collection/refund period.

Continuation of the Low Income Program beyond December 31, 2023, will be contingent on the continuation of full cost recovery through the RDM Adjustment or an equivalent mechanism.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(F) [RESERVED FOR FUTURE USE]

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(G) Delivery Revenue Surcharge

As directed by the Public Service Commission in Case19-E-0065, the Delivery Revenue Surcharge (the "Surcharge") will collect Allowed Pure Base Revenue shortfalls that result from extension of the Case 19-E-0065 suspension period, plus interest at the Other Customer Capital Rate, over 11 months commencing February 1, 2020. The Surcharge will be shown on the Statement of Delivery Revenue Surcharge filed with the Public Service Commission, apart from this Rate Schedule. Unless otherwise directed by the Commission, the Company will file Statements no less than three days before their effective date. The Delivery Revenue Surcharge amount will be shown as a single monetary amount on the monthly bill rendered to PASNY.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(H) Other Charges and Adjustments

Definition:

"PASNY Allocation" is the ratio of forecasted Rate Year Delivery Revenues under this Rate Schedule to total combined forecasted Rate Year Delivery Revenues under this Rate Schedule and the Schedule for Electricity for the Rate Year in effect at the commencement of the collection period except as stated below in (2)(a).

(1) Charge for Demand Management Programs

A charge will be applicable to service under this Rate Schedule to recover the allocation to PASNY of program costs, as incurred, to be collected over a reasonable period of time, for Commission approved Energy Efficiency and Demand Response Programs to the extent not recovered through another mechanism.

(2) Charge for PJM OATT Rates and Charges

(a) A charge will be applicable to service under this Rate Schedule to recover the allocation to PASNY of PJM OATT rates and charges associated with the 1,000 MW firm transmission service contracted with PJM that are applicable to the period April 1, 2013 through December 31, 2013, net of the amount of PSEG wheeling charges reflected in rates during that period. The amount will be collected under this Rate Schedule over the 10 months commencing March 2014, based on the PASNY Allocation for the Rate Year that commenced April 2013.

(b) A charge will be applicable to service under this Rate Schedule to recover the allocation to PASNY of PJM OATT rates and charges associated with the 1,000 MW firm transmission service contracted with PJM that are applicable to the period commencing January 1, 2014. Commencing March 2014, rates and charges will be collected monthly as incurred and will include an adjustment to recover over a three-month period rates and charges applicable to the period January and February 2014.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(H) Other Charges and Adjustments - Continued

(2) Charge for PJM OATT Rates and Charges - Continued
(b) – Continued

The amount to be collected under this Rate Schedule will be based on the PASNY Allocation. However, should the cost allocation to NYPA exceed $4.6 million in any Rate Year, that excess will be collected from Customers under the Schedule for Electricity. Commencing Rate Year 2017, if PJM OATT rates and charges are incurred for less than a full Rate Year, the cost allocation to NYPA will be limited to $4.6 million multiplied by the number of months in the partial year divided by 12 months. Any retroactive PJM billing adjustments required to be collected will be subject to the caps described above. Should the cost allocation to NYPA exceed $4.6 million or the otherwise applicable limitation for any Rate Year or partial Rate Year, as applicable, any excess will be collected from Customers under the Schedule for Electricity.

(3) Charges Associated with the Brooklyn/Queens Demand Management Program

A charge will be applicable to service under this Rate Schedule to recover the allocation to PASNY of costs related to the Brooklyn/Queens Demand Management Program, other than costs recovered in base rates. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(4) Charge to Recover Standby Performance Credits and Standby Reliability Credits

A charge will be applicable to service under this Rate Schedule to recover the cost of Standby Performance Credits and Standby Reliability Credits provided to PASNY Customers pursuant to General Rule 20.5.3 and 20.5.4 of the Schedule for Electricity.

(5) Charges Associated with the Targeted Demand Management Program and Demonstration Projects

A charge will be applicable to service under this Rate Schedule to recover the allocation to PASNY of costs related to the Targeted Demand Management program and Reforming the Energy Vision Demonstration Projects, other than costs recovered in base rates. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(6) Contribution to Earning Adjustment Mechanisms ("EAMs") and Other Revenue Adjustments

Adjustments will be applicable to service under this Rate Schedule to collect/credit a portion of positive incentives earned by the Company under EAMs, any other incentives associated with Company incentive mechanisms, and revenue adjustments associated with Company performance metrics and mechanisms, as authorized by the Commission. EAMs associated with Energy Efficiency targets (Deeper Savings EAM, Share the Savings EAM, and Low- and Moderate-Income and Disadvantaged Communities EAM) will not be recovered under this Rate Schedule. The amounts for all other EAMs, incentives and revenue adjustments to be recovered under this Rate Schedule will be based on the PASNY Allocation and applied in equal increments over a 12-month period or as otherwise authorized by the Commission.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(H) Other Charges and Adjustments - Continued

(7) [RESERVED FOR FUTURE USE]

(8) Costs and Incentives Associated With Non-Wires Alternatives ("NWAs")

A charge will be applicable to service under this Rate Schedule to recover PASNY's allocation of costs for implementation of NWAs (adjusted for the carrying charge of any displaced capital project reflected in the Average Electric Plant in Service Balance that would otherwise be deferred for customer benefit), plus PASNY's allocation of NWA incentives earned by the Company. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(9) Recovery of Bill Credits to Export-only Customers

A charge will be applicable to service under this Rate Schedule to recover PASNY's allocation of the cost of bill credits provided to export-only customers pursuant to Special Provision I of SC 11 of the Schedule for Electricity. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(10) Clean Energy Standard Delivery Surcharge

Charges related to the Clean Energy Standard Delivery Surcharge ("CESD") will be applicable to service under this Rate Schedule to recover the allocation to PASNY of costs related to two components: Tier 2 Maintenance Contracts and Backstop Charges. Estimated costs related to Tier 2 Maintenance Contracts will be collected over each 12-month period commencing April 1. Estimated costs for Backstop Charges will be collected over a period of one-to-twelve months, depending on the size of the costs.

The amount to be recovered under this Rate Schedule for Tier 2 Maintenance Contracts and Backstop Charges will be based on the PASNY Allocation. Each charge will collect PASNY's pro rata portion of the total estimated costs for that component over its applicable collection period and the difference, excluding Uncollectible-bill Expense, between PASNY's pro rata portion of total actual costs and amounts recovered under this Rate Schedule for that component for prior periods.

An adjustment will be made to the total charge for each component under this Rate Schedule to reflect Uncollectible-bill Expense. Uncollectible-bill Expense will be determined using the Uncollectible Bill Factor identified in General Rule 26.1.2(b)) of the Schedule for Electricity).

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(H) Other Charges and Adjustments - Continued

(14) Direct Current Fast Charging ("DCFC") Surcharge

The DCFC Surcharge will be applicable to service under this Rate Schedule to recover program costs related to the DCFC per-plug incentive available to qualified DCFC electric vehicle charging stations.

The monthly DCFC Surcharge was developed by multiplying the DCFC Surcharge per kWh (calculated as specified in the Commission's February 7, 2019 order in Case 18-E-0138), by PASNY's annual delivery kWhr, and dividing the result by twelve months. The DCFC Surcharge is applicable for the 12-month period January 1, 2020 through December 31, 2020.

(15) Electric Vehicle Make-Ready ("EVMR") Surcharge

As specified in Case 18-E-0138, the EVMR Surcharge will be applicable to service under this Rate Schedule to recover the allocation to PASNY of EVMR costs. The EVMR costs include: (1) Company-owned Make-Ready Work, (2) Customer-owned Make-Ready Work, (3) Other Programs and (4) Make-Ready Implementation Costs. The amounts to be recovered under this Rate Schedule will be based on General Rule 26.10 of the Schedule for Electricity.

(16) Reliable Clean City ("RCC") Projects Surcharge

A charge will be applicable to service under this Rate Schedule to recover PASNY's allocation of carrying charges related to the Rainey to Corona Project, the Gowanus to Greenwood Project, and the Goethals to Fox Hills Project, collectively, the Reliable Clean City ("RCC") projects, as authorized by the Commission's April 15, 2021 Order in Case 19-E-0065. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(17) Unbilled Fees Adjustment

The Unbilled Fees Adjustment will be applicable to service under this Rate Schedule to recover and reconcile deferred late payment fees and other fees originally associated with customer non-payment ("Unbilled Fees") for Rate Year One (i.e., 2020) as authorized by the Commission in Case 19-E-0065. The Company will recover these Unbilled Fees commencing January 1, 2022, through December 31, 2022.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(H) Other Charges and Adjustments - Continued

(17) Unbilled Fees Adjustment – Continued

The Company will reconcile the approved fees in Rate Years Two (i.e., 2021) and Three (i.e., 2022) in Case 19-E-0065 without any threshold requirement and collect/pass back any variance. The Company will begin its recovery or pass back of the approved fees for Rate Year Two on January 1, 2023, through December 31, 2023 and for Rate Year Three on January 1, 2024, through December 31, 2024.

The Company will reconcile the actual annual late payment fee revenues with Commission approved levels included in base rates in 2023 and future years and collect/pass back any variance over a subsequent twelve-month period as authorized by the Commission.

The amount to be recovered or passed back under this Rate Schedule will be based on the PASNY Allocation. The amount to be recovered or passed back to PASNY will be determined by dividing the amount to be recovered or passed back over the collection period by the number of months in the collection period.

(18) Reconciliation of Storm Costs

A charge will be applicable to service under this Rate Schedule to recover PASNY's allocation of the amount by which annual storm costs exceed the annual rate allowance, when such excess amount exceeds $7 million each year, up to 2.5% of delivery revenue each year. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(19) Reconciliation of Interference Costs

A charge will be applicable to service under this Rate Schedule to recover PASNY's allocation of carrying charges associated with interference costs causing an exceedance of the net electric plant target. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(20) Reconciliation of Property Taxes

An adjustment will be applicable to service under this Rate Schedule to recover PASNY's allocation of the difference between the actual annual property taxes and Commission approved levels in base rates. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

PASNY DELIVERY SERVICE

Additional Delivery Charges and Adjustments - Continued

(H) Other Charges and Adjustments - Continued

(21) Uncollectible Bill Expense Adjustment

An adjustment will be applicable to service under this Rate Schedule to recover PASNY's allocation of the difference, plus interest, between the actual annual UB expense and Commission approved levels in rates for the period January 1, 2020 through December 31, 2025. After that time, the Company may recover any under-collections. Additionally, a charge or credit will be included for the reconciliation of the non-Credit and Collections related portion of the POR Discount reconciliation. The amount to be recovered or passed back under this Rate Schedule will be based on the PASNY Allocation.

(22) Charge to Recover COVID-19 BIR Rate Reductions

A charge will be applicable to service under this Rate Schedule to recover PASNY's allocation of the amounts associated with rate reductions provided to Customers under the COVID-19 BIR program. The amount to be recovered under this Rate Schedule will be based on the PASNY Allocation.

(23) Statement of Other Charges and Adjustments

The amount to be charged for each of the above items will be separately shown on the Statement of Other Charges and Adjustments ("OTH Statement") filed with the Public Service Commission, apart from this Rate Schedule. Unless otherwise directed by the Commission, the Company will file OTH Statements no less than three days before their effective date.

For purposes of billing, all of the above items will be shown as one total amount under "Other Charges and Adjustments."

P.S.C. No. 9 – Gas

TARIFF LEAVES

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General Information – Continued

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GENERAL INFORMATION - Continued

II. Definitions and Abbreviations of Terms Used in this Rate Schedule - Continued

- **“Critical Care Customer”** refers to any Interruptible or Off-Peak Firm customer premise that provides life-saving or life-sustaining service, including the delivery of newborns, (i.e., hospitals providing critical care, nursing homes, assisted living facilities, rehabilitation centers, correctional facilities, homeless shelters, public schools providing emergency shelter or refuge during a declared emergency, or other designated areas of refuge, identified on an annual basis by local or state governmental agency), where public safety could be affected by a need to relocate the occupants. All other Customers will be considered Non-Critical Care.

- **"Customer"** includes both a present consumer of and an applicant for the Company's service.

- **"Deferred Payment Agreement"** is a written agreement for the payment of outstanding charges over a specified period of time. It must be signed in duplicate by a Company representative and the Customer, and each must receive a copy, before it becomes enforceable by either party.

- **"Delinquent Non-Residential Customer"** is a Customer who has made a late payment on two or more occasions within the previous 12 month period.

- The **“GTOP”** or **“Sales and Transportation Operating Procedures”** provides Customers taking service under SC 9 and SC 12 and Sellers taking service under SC 20 with additional details about their rights and responsibilities under those service classifications.

- **“Interval Meter”** means a meter with communications capability that records gas usage in increments of 60 minutes or less and includes meters installed under the Company’s AMI program.

- **“Interval Metering”** means the measurement of a Customer’s Gas usage by means of an Interval Meter.

- **"Late Payment"** means any payment made more than 20 calendar days after the date payment was due. Payment is due whenever specified by the Company on its bill, provided such date does not occur before personal service of the bill or 3 calendar days after the mailing of the bill.

- **"Levelized Payment Plan"** is a billing plan designed to reduce fluctuations in a Customer's bill payments due to varying, but predictable, patterns of consumption.

- **“Local RNG Production”** refers to Renewable Natural Gas production facilities interconnected directly to the Company’s gas distribution facilities in accordance with the Company’s RNG Interconnection Procedures, as specified in the Gas Sales and Transportation Operating Procedures. The gas quality requirements and operating procedures applicable to Local RNG Production are provided in the Gas Sales and Transportation Operating Procedures.

(General Information - Continued on Leaf No. 13)

GENERAL INFORMATION - Continued

II. Definitions and Abbreviations of Terms Used in this Rate Schedule - Continued

- **"Main"** means a pipeline located on a public or private right-of-way which is generally available or used to transport gas to more than one service line.

- **"New Customer"** is a Customer who was not the last previous Customer at the premises to be served, regardless of whether such Customer previously was or is still a Customer of the Company at a different location.

- **"Non-Business District"** is an area that is predominantly residential or is not otherwise designated as a Business District.

- **"Non-Residential Applicant"** is any person, corporation or other entity who has requested service under this Rate Schedule who is not a residential applicant.

- **"Non-Residential Customer"** is any person, corporation or other entity supplied with service under this Rate Schedule and pursuant to an accepted application for service who is not a residential Customer.

- **"Payment"** is considered to be made on the date when it is received by the Company or one of its authorized agents.

- **"Point of Service Termination"** means the point at which the Company terminates its service pipe and the Customer begins his/her piping.

- **"Public Right-of-Way"** means the territorial limits of any street, avenue, road or way (other than a limited access thoroughfare) that is for any highway purpose under the jurisdiction of the State of New York or the legislative body of any county, city, town or village and is open to public use.

- **"Rate Schedule"**, also sometimes referred to as the "Tariff", means the Company's Schedule for Gas Service as filed with the New York Public Service Commission.

(General Information - Continued on Leaf No. 14)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

3. Installation of Mains and Services - Continued

(B) Company Cost Responsibilities - Continued

(1) The amounts paid to governmental authorities for permits to do the work required and all paving charges that are legally imposed by any governmental authority for the repair or replacement of any street or sidewalk disturbed in the course of such installation;

(2) Firm Residential Applicant - Non-Heating:

The material and installation costs relating to up to 100 feet of any combination of main and service line measured from the centerline of the public right-of-way (or the main if it is closer to the Customer and development will be limited to one side of the right-of-way for at least 10 years), service connections and appurtenant facilities, but not less than 100 feet of main (if necessary) plus the length of service line necessary to reach the edge of the public right-of-way;

(3) Firm Residential Applicant – Heating:

(a) The material and installation costs relating to up to 100 feet of any combination of main and service line measured from the centerline of the public right-of-way (or the main if it is closer to the Customer and development will be limited to one side of the right-of-way for at least 10 years), service connections and appurtenant facilities; but not less than 100 feet of main (if necessary) plus the length of service line necessary to reach the edge of the public right-of-way;

(General Information - Continued on Leaf No. 31)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

3. Installation of Mains and Services - Continued

(B) Company Cost Responsibilities – Continued

(3) Firm Residential Applicant - Heating – Continued

(b) For a residential structure containing five or more attached dwelling units, where each dwelling unit is individually metered for gas service for heating, the material and installation costs relating to:

(i) 100 feet of main and appurtenant facilities multiplied by the total number of units in the multiple dwelling or the main and appurtenant facilities necessary to provide service to such structures (whichever is less); and

(ii) 100 feet of service line for each applicant, service connections and appurtenant facilities or the length of service line necessary to provide gas service for heating to such applicant (whichever is less);

Options (a) and (b) above for residential heating service may not be combined.

(4) Firm Non-Residential Applicant:

If an applicant which will be a firm, non dual-fuel Customer requests service other than residential service, the material and installation costs relating to:

(a) up to 100 feet of main and appurtenant facilities; and

(b) any service line, service connections and appurtenant facilities located in the public right-of-way;

(5) Firm Dual-Fuel Applicant:

The material and installation costs relating to any main reinforcements and appurtenant facilities, except as discussed in Section III.3. (C) (2) below.

(General Information - Continued on Leaf No. 32)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

3. Installation of Mains and Services - Continued

(C) Charges for Additional Facilities - Continued

(1) - Continued

(a) - Continued

surcharge shall not exceed 20 percent per year of the estimated reasonable cost of a 4-inch main (in the case of low pressure distribution), or a 2-inch main (in the case of high pressure distribution) unless the estimated consumption of the proposed Customer requires the installation of a larger-sized main, in which event the surcharge shall not exceed 20 percent per year of the actual reasonable cost of such main. The surcharge shall commence when gas service is first available to an applicant and shall be paid ratably for each billing period;

(b) whenever more than one Customer is connected to a main extension, the surcharge shall be so adjusted that the Company shall not receive in any one calendar year a greater percentage from all Customers served from the main extension than that applicable to such extension. The surcharge shall also be reasonably allocated among the Customers being served from the main extension, taking into account the portion of mains and appurtenant facilities which the Company is required to provide without charge to each Customer served from such facilities;

(General Information - Continued on Leaf No. 34)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

3. Installation of Mains and Services - Continued

(C) Charges for Additional Facilities - Continued

(1) - Continued

(c) each surcharge shall cease:

(i) whenever the length of a main extension required to be provided without charge to all Customers served from such extension shall equal or exceed the total length of such extension; or

(ii) after a period of ten years following its commencement;

(d) should the adjusted gas revenue from all Customers served from a main extension exceed the carrying cost of the entire extension, any surcharges or upfront contributions paid by such Customers during the preceding five years shall be refunded to such Customers;

(General Information - Continued on Leaf No. 35)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

3. Installation of Mains and Services - Continued

(C) Charges for Additional Facilities - Continued

(2) Any firm Customer who commences service on or after October 1, 2004, and who has or who later installs dual-fuel capability, shall reimburse the Company for all costs related to any main reinforcements and appurtenant facilities incurred by the Company on behalf of the Customer, if for any annual period during the first 5 years of service, the Customer's actual usage is less than 50% of the Customer's Annual Allocation, as determined in accordance with the Company's Sales and Transportation Operating Procedures. Reimbursement shall be through a main reinforcement surcharge (MRS), which is subject to the following provisions:

(a) the MRS shall be calculated to recover the actual cost of the main reinforcement and appurtenant facilities, including return, depreciation, taxes and maintenance during the first 5 years of service.

(b) the MRS shall commence in the next monthly billing period following the period in which it was determined that the Customer was subject to the MRS.

(c) the amount of the MRS collected in any annual period following its commencement shall not exceed 20% of the amount calculated in subsection (2) (a) above.

(d) each main reinforcement surcharge shall cease:

(i) whenever cumulative adjusted gas revenues collected equal or exceed the cost being recovered through the MRS, or

(ii) after a period of ten years following its commencement,

whichever shall occur first.

(3) A successor to a Customer connected to a gas main extension constructed under General Rule III. 3. (C) "Charges for Additional Facilities" shall, as a condition of receiving service, agree to pay to the Company the rates set forth in the Service Classification under which gas service is to be supplied to the Customer and in addition the amount of surcharge allocable to the Customer under the provisions of General Rule III. 3. (C).

(General Information - Continued on Leaf No. 36)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

5. Service Equipment - Continued

(C) Location of New Gas Meters and Relocation of Existing Gas Meters - Continued

The Company may also relocate/elevate gas meters which are located in a flood plain.

The Company will make exceptions to the outdoor metering requirement associated with planned service line replacements, service line repairs or new service installations:
(i) where the Customer refuses to provide consent to such relocation;
(ii) where local building codes or regulations preclude outside meters;
(iii) for safety considerations;
(iv) where space constraints or physical barriers preclude relocation; and/or
(v) when work involved is an emergency service line repair/ replacement.

(2) *For All Other Buildings*: For all other buildings, both residential and non-residential, the Company will locate and install gas meters outside the Customer's building when installing a new service installation. The Company will relocate and install gas meters outside of the Customer's building when performing any planned service line replacement or under other circumstances that offer the Company and the Customer the opportunity to relocate the gas meter outside, such as a major property renovation.

The Company may also relocate/elevate gas meters which are located in a flood plain.

The Company will make exceptions to locating or relocating gas meters outside of the Customer's building:
(i) where the Customer refuses to provide consent to such relocation;
(ii) where local building codes or regulations preclude outside meters;
(iii) for safety considerations;
(iv) where space constraints or physical barriers preclude relocation; and/or
(v) when responding to an emergency.

(3) Customers that exercise an option to refuse an outdoor meter installation under exception (i) above
(i) will be asked to sign a form explaining the reason(s) for refusal, and acknowledging that they are aware of the benefits of having their meters outside; and
(ii) will be subject to a fee per building for costs related to survey/inspection of inside piping if Customer refusal is the sole reason for the meter remaining/being located inside and none of the other above stated exceptions applies. The survey/inspection fees are as follows:
(a) For 1-3 family: $255
(b) For 4 family and greater: $475

(D) Seals:

The Company will seal all meters before installation. Meter equipment may be locked or sealed when service is shut off. No person, except a duly authorized employee of the Company, shall be permitted to break or replace a seal or lock, or to alter or change a meter or its connections or location, or to alter a gas pressure regulator.

(General Information - Continued on Leaf No. 45)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

8. Metering and Billing - Continued

(C) Access to Premises - Continued

(2) Inspection and Examination of Company Apparatus:

A duly authorized representative of the Company may enter Customer premises at all reasonable times upon exhibiting proper identification and written authority for the purpose of inspecting and examining the meters, pipes, fittings, wires and other apparatus for regulating, supplying and/or ascertaining the quantity supplied. Inspections and examinations also include performing leakage surveys and atmospheric corrosion inspections. However, that in non-emergency situations, entry to the premises of residential Customers shall be limited to non-holiday workdays between 8 A.M. and 6 P.M., or at such other reasonable times as may be requested by a residential Customer; or between 8 A.M. and 9 P.M. on any day when there is evidence of meter tampering or theft of service. However, when an emergency may threaten the health and safety of a person, the surrounding area, or the Company's distribution system, or when authorized by a court order, entry by authorized Company representatives shall be permitted at any time for purposes of the inspection and examination permitted under this paragraph. A Customer who at any time, directly or indirectly prevents or hinders the inspection or examination provided for under this provision, at any reasonable time, may be billed a $100 penalty charge per premises in a Non-Business District or a residential premises in a Business District and a $500 penalty charge per non-residential premises in a Business District for each such offense. Such offenses include a Customer or access controller missing two or more appointments to allow a duly authorized representative of the Company to gain access to the premises or denying the Company access to the premises to perform a leakage survey and/or atmospheric corrosion inspection. After the second attempt to perform a survey and/or inspection, the $100 penalty or $500 penalty may be charged to a Customer at the Company’s discretion for each failed attempt to gain access for every billing period until access is gained. Additionally, customers will bear all costs associated with legal action, including payments to law enforcement personnel, to gain access to the Company’s gas meter. In addition, the Company shall have all other remedies against such Customer as are provided under this tariff or at law.

Except to the extent prevented by circumstances beyond its control, the Company shall conduct a field inspection of Company apparatus supplying a non-residential Customer as soon as reasonably possible and within 60 calendar days of the following:

(General Information - Continued on Leaf No. 49)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

8. Metering and Billing – Continued

(V) Reconnection Charges

A reconnection charge shall apply when the Company sends an employee to the Customer's premises to re-establish service to a Customer whose service has been discontinued for non-payment of a deposit or for any of the rates and charges billed pursuant to the Company's Schedule for Gas Service. The charge for re-establishment of service to a Service Classification ("SC") No. 1 Customer or corresponding SC No. 9 Rate (A)(1) Customer who is not enrolled in the Low Income Program, shall be $65.00 each time. The charge for re-establishment of gas service to all other gas Customers excluding Low Income Customers shall be $245.00 each time, except as noted below.

Beginning January 1, 2020, the charge for re-establishment of gas service to Low Income Customers shall be waived on a first come, first serve basis up to a target cost of $75,000 in each twelve-month period commencing January 1 ("Rate Year"), unless the fee waiver program ends prior to the end of such Rate Year, as explained below. After the target is reached in a Rate Year, the reconnection charge for each Low Income Customer shall be $65.00 for each occurrence in such Rate Year.

The fee waiver program will end in any Rate Year once the cost of the program equals the target cost of $75,000 in such Rate Year. The Company will notify the parties in its most recent gas rate plan if it projects that the target cost will be reached during any Rate Year.

Street reconnections shall be performed at cost and recover, where applicable the costs of labor, material, corporate overhead and taxes.

Any reconnection fees waived in any Rate Year, will be recovered through the Low Income Reconciliation Adjustment component of the MRA over a twelve-month period commencing the following January 1.

(General Information - Continued on Leaf No. 76.2)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

8. Metering and Billing – Continued

(W) AMR/AMI Meter Opt-Out – Continued

(3) Access to Premises

If a Customer opts out of AMR or AMI metering, as applicable, or refuses to permit installation of such metering, and, thereafter, the Company has no access to the meter on four consecutive bi-monthly cycle reading dates, the Customer or access controller will be required to provide the Company with access to install, or re-install, an AMR or AMI meter at the Company's discretion. As an alternative, where practicable, a Customer, at Customer expense, can furnish, install, and maintain the facilities necessary to accept outdoor metering.

Customers who opt out of AMR or AMI metering may elect to participate in AMI metering at a later date as described on the following website:
https://www.coned.com/en/our-energy-future/technology/innovation/smart-meters.

(X) Charge for Replacing a Damaged Meter

If the access controller to a Company-owned meter did not exercise reasonable care or the meter was damaged due to tampering, the access controller will be charged for the removal and replacement of the meter including any equipment that was damaged. The charge for the removal and replacement shall be at cost and shall be assessed on the account of the access controller even if the damaged meter was for the account of another Customer, except that if the meter was damaged due to tampering, the charge shall be assessed on the account of the Customer who benefited from such tampering.

9. Notices

(A) Notices to and from the Company:

Any notice to the Company under any agreement, other than an oral agreement under Service Classification No. 1, shall be delivered to it in writing and not otherwise. Bills shall be deemed presented and other notices duly given (except a notice of discontinuance of service for non-payment of bills) if delivered to the Customer personally or if mailed to the Customer at the premises supplied, or at the last known address of the Customer, or if left at either of such places, or if delivered or mailed to the agent or representative of the Customer, or if left at the last known address of such agent or representative. A notice of discontinuance of service for non-payment of bills shall be given as required by law.

(General Information - Continued on Leaf No. 78)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

9. Notices – Continued

(A) Notices to and from the Company: – Continued

Notices to and from the Company to an SC No. 20 Marketer and Direct Customers shall also be subject to the provisions set forth in the UBP and the Company’s Sales and Transportation Operating Procedures.

(B) Notice of Change in Ownership or Occupancy of Premises:

Immediately upon the sale, lease or any other change in occupancy of the premises or any portion thereof supplied under an agreement for service, the Customer shall give written notice to the Company of such change together with the name and address, if known, of the successor in occupancy of such premises or portion thereof; provided, however, that such notice may be given orally by a Customer for residential service under Service Classification No. 1, unless such Customer is a party to a service classification rider agreement, or an agreement for extension of gas mains or connection thereto.

10. Limitations as to Availability of Service Classifications

(A) Customer's Eligibility for Service:

Upon request by the Company, the Customer shall furnish satisfactory proof of eligibility to be supplied under the Service Classification and Rider, if any, for which application is made or under which service is supplied, and that all the gas supplied will be or is being used by the Customer according to the conditions of the application or agreement for service. Upon any change in such use contrary to such conditions the Customer shall forthwith notify the Company thereof in writing. In the event that the Customer's use of service is contrary to the provisions of the Service Classification or Rider, or both, under which the Customer is being served, the Customer's agreement shall be deemed to be terminated or to be modified as may be required to conform to the appropriate provisions of the Rate Schedule and the Customer will be billed accordingly and, upon request by the Company, the Customer shall make a new application for service in accordance with General Rule III 1 (A) "Applications" appropriate to the service for which the Customer is eligible under the provisions of this Rate Schedule.

(B) Redistribution of Gas Service:

Gas will not be supplied to any Customer except for the Customer's own use or for the use of the Customer's tenants in the building or premises supplied with gas under the service agreement between the Company and the Customer. A Customer shall not submeter, resell or otherwise dispose of any gas supplied to the Customer under any Service Classification; except that a Customer of the Company may redistribute (provided no specific charge is made therefor) or submeter (provided gas charges do

(General Information - Continued on Leaf No. 79)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

13. Attachments of New Gas Customers and Supplying of Gas to Existing Customers

Acceptance of service applications and providing new or additional service will be contingent upon the following:

(1) The Company has an adequate supply of gas to meet the requirements of such applicants; and

(2) All applications must be in writing in accordance with the terms and conditions of this Rate Schedule and the Company's Sales and Transportation Operating Procedures and must be accompanied by a statement indicating the intended use of the gas.

14. Gas Service Curtailments

(A) If the Company in its judgment finds that it is unable to satisfy the full requirements of its Customers (including intra-Company transfer requirements) and finds it necessary to curtail sales and/or transportation service, the Company may curtail service to a Customer or give oral, written or electronic notice of curtailment. If notice of curtailment is given, a Customer must curtail its use of service pursuant to the notice.

(B) If notified of a curtailment, Energy Service Companies (ESCOs) and Direct Customers (DCs) are still required to deliver their Maximum Daily Transportation Quantity ("MDTQ"), including Local RNG Production to the Citygate as directed by the Company, unless an upstream force majeure interruption or curtailment prevents the ESCO or DC from securing and delivering its MDTQ to the Citygate. ESCOs and DCs will be compensated for the cost of the diverted gas as discussed in Section E.

(General Information - Continued on Leaf No. 86)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

14. Gas Service Curtailments - Continued

(C) - Continued

Within Category 8, Interruptible Service Classification 12 Customers and equivalent Service Classification 9 Customers shall generally be curtailed in reverse order of their revenue contribution and after factoring in the human needs criterion.

(D) The following provisions shall govern curtailments and notices of curtailment of sales and transportation services resulting from a deficiency of capacity in gas transmission lines that are owned by the Company or that the Company has a contractual right to use (other than interstate pipeline transmission lines).

(1) In the event of a transportation-capacity deficiency, curtailments and notices of curtailments will normally be made according to the following priorities to the extent permitted by operating feasibility, with Priority (2) being curtailed before Priority (1):

(a) **Priority 1:** All firm sales and firm transportation services to Customers with dual-fuel or alternate energy facilities and off-peak firm sales and transportation services, firm and off-peak firm intra-Company transfers; and non-tariff firm and off-peak firm sales and transportation services;

(b) **Priority 2:** Interruptible sales and transportation services; interruptible intra-Company transfers; non-tariff interruptible sales and transportation with plant protection requirements assigned the highest priority.

(General Information - Continued on Leaf No. 88)

GENERAL INFORMATION - Continued

III. General Rules, Regulations, Terms and Conditions under Which Gas Service Will Be Supplied, Applicable to and Made a Part of All Agreements for Gas Service - Continued

14. Gas Service Curtailments - Continued

(E) In the event gas supply intended for lower priority customers is diverted from ESCOs and DCs to serve higher priority Customers pursuant to provisions (C) and (D) of this Section, the ESCO or DC from whom gas is diverted will be compensated for the volume diverted at the market price of gas during the curtailment. The market price of gas is defined as a weighted average price equal to the product of the percentage weightings and the "Midpoint" gas price for Transco Zone 6 – N.Y., Texas Eastern Transmission (Tetco M3), and Iroquois Gas Transmission System (Z2) for the applicable diverted gas flow day as published by Platts in the Gas Daily Price Guide. If the ESCO/DC can demonstrate to the Company's satisfaction that its contract calls for a higher price the Company will reimburse the ESCO/DC at the contract price. To the extent that the Company diverts natural gas produced by Local RNG Production, the Company shall not be responsible for compensating the ESCO for the value of renewable attributes. Such attributes shall be retained by the ESCO. The ESCO/DC shall be responsible for providing the Company with adequate support of the higher contract price. Customers of ESCOs who are affected by a curtailment must seek compensation directly from their ESCO. When gas is diverted to serve firm sales or firm transportation service classifications, payments made by the Company will be recovered through the Monthly Rate Adjustments applicable to firm sales and firm transportation customers in accordance with General Information Special Adjustments IX.15. (Curtailment Cost Recovery Charge).

(F) Curtailment Guidelines

The following guidelines will inform the Company in its application of the curtailment requirements:

(a) As circumstances permit, the Company shall first seek voluntary curtailments to alleviate an emergency situation. Then, the Company shall implement a curtailment after all mutual aid, contractual and other non-contractual supply tools, Operational Flow Orders, interruption of contractually-interruptible load, and supply acquisition options have been utilized.

(General Information - Continued on Leaf No. 90)

GENERAL INFORMATION - Continued

IV. Special Services Performed by the Company for Customers at a Charge - Continued

1. Special Services at Cost - Continued

(E) Inspect or clear drips on the service pipe beyond the point of service termination;

(F) Install service lines, service connections, and appurtenant facilities in addition to those required under General Rule III 3 (C) (3).

(G) Change an existing customer's service configuration from multiple-meter to a single-meter configuration, including all costs associated with removing and upgrading meter(s).

(H) Provide a meter or auxiliary metering equipment not normally furnished by the Company and not required for billing the customer's service, including meter upgrades and furnishing of equipment that permits remote reading of the meter.

2. Definition of Cost

The cost to be charged for the furnishing of the special services listed in Paragraph 1. "Special Services at Cost", consists of the following elements of cost where applicable.

(A) Labor of the Company organization unit involved at average payroll rate plus related expenses and indirect costs. Overtime and Sunday rates will be charged where applicable;
(B) Material at the average actual storeroom price plus 13% for handling cost (Sales Taxes to be added where applicable);
(C) Use of transportation vehicles at rates covering operation, maintenance, carrying charges and taxes;
(D) Contract work and sundry vendors' bills at invoice cost, including any taxes contained therein;
(E) Use of large tools and equipment at rates covering operation, maintenance and carrying charges;
(F) Corporate overhead for the above five defined costs, (A through E) at (a) 7% for engineering and drafting, unless the labor cost for those services is separately stated or was already charged on a prior invoice, (b) 13% for construction management, if applicable, and (c) 3% for administration;
(G) Salvage credit at storeroom price of materials reduced by salvaging cost, or at junk value.

The above-described costs, where applicable, shall be increased to reflect the percentage Increase in Rates and Charges, as explained in General Information Section VIII and shown on the related Statement.

(General Information - Continued on Leaf No. 118)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) – Continued

RIDER D - Continued

Applicable to Service Classification Nos. 2 and 9
(Subject to the provisions thereof)

EXCELSIOR JOBS PROGRAM – Continued

(B) Eligibility - Continued

allow time for the Company to receive either a new Tax Certificate or Tax Certification. If a new Tax Certificate or Tax Certification is received during the grace period, any rate reductions applied during the grace period will be counted toward the 12 monthly billing periods that commenced on the anniversary. If a new Tax Certificate or Tax Certification is not received by the end of the grace period, the rate reductions will cease at the end of the grace period. If a new Tax Certificate or Tax Certification is received after the end of the grace period, the rate reductions will be applied prospectively for the remaining billing periods of the 12 monthly billing periods that commenced on the anniversary.

Should there be a gap of one or more years before the Company receives a new Tax Certificate or Tax Certification, the Customer will be eligible for delivery rate reductions for (a) the twelve monthly billing periods that commence on the current year’s anniversary, if the Company receives the new Tax Certificate or Tax Certification on or before the anniversary, or (b) the remaining billing periods of the twelve monthly billing periods that commenced on the current year’s anniversary, if the new Tax Certificate or Tax Certification is received after the anniversary.

(C) Restrictions as to the Eligibility of This Rider

Customers being served under Rider H of this Rate Schedule are not eligible for service under this Rider.

(D) Term

Customers will be eligible for EJP delivery rate reductions specified under this Rider for up to ten consecutive 12-month periods. Customers who discontinue service under this Rider to commence service under Rider H will not be eligible thereafter to receive service under this Rider.

(General Information - Continued on Leaf No. 128)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) – Continued

RIDER D - Continued

Applicable to Service Classification Nos. 2 and 9
(Subject to the provisions thereof)

EXCELSIOR JOBS PROGRAM - Continued

(E) Base Rates

Delivery rate reductions under this Rider shall apply only to monthly usage as defined under Incremental Billing Determinants, for:

i) New Customers, and

ii) Existing Customers if their Incremental Billing Determinants increase over their Baseline Billing Determinants by at least 25% for the month.

The applicable rate below is based on the customer's eligibility for Rate I or Rate II as specified under Service Classification No. 2 of this Rate Schedule. The Customer's monthly gas usage not subject to delivery rate discounts under this Rider will be billed at the applicable base rates set forth in Service Classification No. 2.

For Customers receiving service under this Rider, the following delivery rate reductions will be applied to monthly Service Classification No. 2 or 9 base tariff charges, including the minimum monthly charge, before application of the Increase in Rates and Charges (as explained in General Information Section VIII and shown on the related Statement).

The applicable Percentage Rate Reduction is based on the date the Customer commenced service under this Rider, as shown below:

Rate Class	Commencement Date		
	2/1/2017 - 1/31/2020	2/1/2020 - 12/31/2022	1/1/2023 and thereafter
SC No. 2 – Rate I or SC No. 9 Rate A (2)	41%	23%	53%
SC No. 2 – Rate II or SC No. 9 Rate A (4)	0%	0%	40%

To the extent that marginal delivery costs change over time, the Company may file amended discounts with the Commission for its review and approval.

(General Information - Continued on Leaf No. 129)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) – Continued

RIDER D - Continued

Applicable to Service Classification Nos. 2 and 9
(Subject to the provisions thereof)

EXCELSIOR JOBS PROGRAM - Continued

(E) Base Rates - Continued

Merchant Function Charge, System Benefits Charge, Billing and Payment Processing Charge, and Weather Normalization Adjustment
A Firm Sales Customer taking service under this rate is also subject to a Merchant Function Charge, System Benefits Charge, Billing and Payment Processing Charge and the Weather Normalization Adjustment as explained in General Information Section IX. A Firm Transportation Customer taking service under this rate is subject to a System Benefits Charge and may be subject to the Billing and Payment Processing Charge if the Customer is not receiving consolidated utility billing as explained in General Information Section IX.

Gas Cost Factor and Monthly Rate Adjustments
A Firm Sales Customer taking service under this Rider is also subject to the Gas Cost Factor applicable to SC No. 2, Rate I or II, of this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII. A Firm Transportation Customer taking service under this Rider is also subject to the Monthly Rate Adjustment as explained in Rate Provision (J)(1) of SC No. 9.

(General Information - Continued on Leaf No. 130)

GENERAL INFORMATION – Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER E – LOW INCOME PROGRAM

Applicable to Service Classifications Nos. 1, 3 and 9
(Subject to the provisions thereof)

(A) Applicability:

To Customers taking service under Service Classification (SC) No. 1, SC No. 3, SC No. 9 Rates (A)(1), (A)(6) and (A)(10) and Rider J Rates I and II and who are enrolled in the Company's Low Income Program ("Low Income Customer").

(B) Definitions:

The following terms are defined for the purposes of this Rider only:

An "add-on benefit", as referenced in the PSC's May 20, 2016 Order Adopting Low Income Program Modifications and Directing Utility Filings in Case 14-M-0565, is an incremental payment that is provided to regular HEAP benefit recipients if their household income is at or below 130% of the federal poverty level, or if their household contains a vulnerable individual (household member who is age 60 or older, under age 6, or permanently disabled). A customer can receive two add-on benefits if both of these conditions apply to their household.

"HEAP" refers to the Home Energy Assistance Program.

(C) Eligibility:

Eligibility for the Company's Low Income Program Tiers is as follows:

Tier 1: A Customer must receive benefits under Supplemental Security Income, Temporary Assistance to Needy Persons/Families, Safety Net Assistance, Medicaid, the Supplemental Nutrition Assistance Program, the federal Lifeline program or and other program associated with the federal Lifeline program, or have received a HEAP benefit in the preceding 12 months.

Tier 2: A Customer must have received a regular HEAP benefit in the preceding 12 months with one add-on benefit.

Tier 3: A Customer must have received a regular HEAP benefit in the preceding 12 months with two add-on benefits.

Tier 4: A Customer must be enrolled in the Direct Vendor or Utility Guarantee Program.

(General Information - Continued on Leaf No. 131)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 149)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G - Continued

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 150)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G - Continued

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 151)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G - Continued

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 152)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G - Continued

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 153)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G - Continued

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER G - Continued

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.1)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER H

Distributed Generation Rate - Continued

(F) Base Rates (per account per month):

Rate I – Applicable to Customers whose distributed generation capacity is less than 5 MegaWatts.

(1) Base Usage Charges:

(a) Applicable to Customers whose distributed generation capacity is 0.25 MegaWatt or less

Minimum Charge for the first 3 therms or less	$235.42	per month
Over 3 therms, for the Summer Period.............................	31.79	cents per therm
Over 3 therms, for the Winter Period	39.72	cents per therm

(b) Applicable to Customers whose distributed generation capacity is greater than 0.25 MegaWatt but less than or equal to 1 MegaWatt

Minimum Charge for the first 3 therms or less.................	$321.69	per month
Over 3 therms, for the Summer Period.............................	31.79	cents per therm
Over 3 therms, for the Winter Period	39.72	cents per therm

(c) Applicable to Customers whose distributed generation capacity is greater than 1 MegaWatt but less than or equal to 3 MegaWatts

Minimum Charge for the first 3 therms or less	$639.96	per month
Over 3 therms, for the Summer Period.............................	31.79	cents per therm
Over 3 therms, for the Winter Period	39.72	cents per therm

(d) Applicable to Customers whose distributed generation capacity is greater than 3 MegaWatts but less than 5 MegaWatts

Minimum Charge for the first 3 therms or less	$852.99	per month
Over 3 therms, for the Summer Period.............................	31.79	cents per therm
Over 3 therms, for the Winter Period	39.72	cents per therm

(2) Minimum Charge (per account per month): The Monthly Minimum Charge shall be the charge for the first 3 therms of gas.

(General Information - Continued on Leaf No. 154.7)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER H

Distributed Generation Rate - Continued

(F) Rate (per account per month) - Continued

Rate I – Applicable to Customers whose distributed generation capacity is less than 5 MegaWatts – Continued

(3) Merchant Function Charge, System Benefits Charge, and Billing and Payment Processing Charge:

A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, the System Benefits Charge, and the Billing and Payment Processing Charge as explained in General Information Section IX. A firm transportation Customer taking service under this rate is subject to the Billing and Payment Processing Charge and the System Benefits Charge as explained in General Information Section IX. The aforementioned rates will be the rates applicable to SC No. 2 Rate I of this Rate Schedule.

(4) Gas Cost Factor and Monthly Rate Adjustments:

A firm sales Customer taking service under this Rider is also subject to the Gas Cost Factor applicable to SC No. 2, Rate I of this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII. A firm transportation Customer taking service under this Rider is also subject to the Monthly Rate Adjustment as explained in Rate Provision (J)(1) of SC No. 9.

(**General Information - Continued on Leaf No. 154.8)**

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER H

Distributed Generation Rate - Continued

(F) Base Rates (per account per month) - Continued

Rate II –

Applicable to 1) Customers whose distributed generation capacity is 5 MegaWatts or greater, but less than 50 MegaWatts, and 2) Customers with separately metered distributed generation facilities at the same Specified Location whose nameplate rating, in aggregate, is at least 5 MegaWatts, and whose nameplate rating for each distributed generation facility at the same Specified Location is at least 1 MegaWatt but less than 50 MegaWatts, as described in Special Provision (H)(5).

(1) Base Usage Charges:

Minimum Charge for the first 3 therms or less.........................	$129.16	per month
Over 3 therms, for the Summer Period.....................................	6.34	cents per therm
Over 3 therms, for the Winter Period	7.97	cents per therm

(2) Minimum Charge (per account per month): The Monthly Minimum Charge shall be the charge for the first 3 therms of gas plus the Contract Demand Charge.

(**General Information - Continued on Leaf No. 154.9)**

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER H

Distributed Generation Rate - Continued

(F) Base Rates (per account per month) – Continued

(3) Merchant Function Charge, System Benefits Charge, and Billing and Payment Processing Charge:

A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, the Billing and Payment Processing Charge, and the System Benefits Charge, as explained in General Information Section IX. A firm transportation Customer taking service under this rate is subject to the Billing and Payment Processing Charge and the System Benefits Charge as explained in General Information Section IX. The aforementioned rates will be the rates applicable to SC No. 2 Rate I of this Rate Schedule.

(4) Gas Cost Factor and Monthly Rate Adjustment:

A firm sales Customer taking service under this Rider is also subject to the Gas Cost Factor applicable to SC No. 2, Rate I of this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII (A). A firm transportation Customer taking service under this Rider is also subject to the Monthly Rate Adjustment as explained in Rate Provision (J)(1) of SC No. 9.

(5) Contract Demand Charge per account per month:

Per therm of Contract Demand as described in the "Determination of Contract Demand" section of this Rider .... $54.94 per therm

(**General Information - Continued on Leaf No. 154.10)**

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER H

Distributed Generation Rate - Continued

(G) Other Provisions Applicable to Rate I and Rate II

A Customer taking service under this Rider shall be subject to all other charges, terms and conditions as set forth in SC Nos. 2 or 9, except for the Revenue Decoupling Mechanism Adjustment and the monthly minimum charge applicable to large volume dual-fuel Customers in SC No. 2.

(H) Special Provisions

(1) **Metering and Communications Equipment:** Customers taking service under Rate II will be required to pay for the capital cost and installation and maintenance costs associated with such metering equipment required to provide service hereunder. The Company will furnish, install and maintain such metering equipment except as indicated below. Rate II Customers will also be required to pay annually the actual costs incurred by the Company in maintaining such equipment.

(General Information - Continued on Leaf No. 154.11)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER H

Distributed Generation Rate - Continued

(H) Special Provisions - Continued

(1) **Metering and Communications Equipment: -** Continued

In cases where the Company is unable to read the meter of a Customer through Customer provided communication equipment, and the Company has determined that the problem is not caused by the Company's meter or equipment, the Customer will be assessed $50.00 on each monthly cycle billing date until the condition is corrected. For each billing cycle the communication equipment is not operational, the Company shall make, and charge such customer for a special meter reading in accordance with the provision in General Information Section IV (3)(b) of this Rate Schedule. If the Company is unable to obtain a meter reading, an estimated bill will be issued. The fee will not be assessed on Customers whose communications equipment is maintained by the Company or Customers with AMI metering equipment.

(2) Separate service lines will not be required for distributed generation service and non-distributed generation service under this Rider. However, if existing services and/or upstream distribution facilities are inadequate, the Customer shall be responsible for all incremental costs incurred by the Company. Customers taking service under this Rider will be charged for additional facilities pursuant to the provisions in the Company's Gas Tariff and in accordance with the Gas Rate Plan adopted in Case 09-G-0795.

(3) Firm Transportation Customers otherwise eligible for service under Service Classification No. 9 of this Rate Schedule will be subject to Daily Delivery Service as set forth in Service Classification No. 9. All customers taking service under this Rider shall be subject to the same procedures for the "Curtailment of Service" as set forth in General Information Section III, 14. of this Rate Schedule applicable to other similarly situated firm commercial and industrial customers of this Rate Schedule.

(4) Electric private generation facilities having a nameplate rating of 5 MW or less and connected in parallel with the Company's electric distribution system will be interconnected as described in the Company's Schedule for Electricity, P.S.C. No. 10 – Electricity and the Standardized Interconnection Requirements appended to the Schedule for Electricity, as each may be modified or superseded from time to time. The Company's Distributed Generation Guide (the "Guide") on the Company's website addresses installation and upgrades of electric generation facilities having a nameplate rating greater than 5 MW and up to 20 MW. When the Guide is revised, it will be posted to the Company's website thirty days before it takes effect.

(General Information - Continued on Leaf No. 154.11.1)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.13)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.14)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.15)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.16)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.17)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.18)

GENERAL INFORMATION – Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.19)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER I

RESERVED FOR FUTURE USE

(General Information - Continued on Leaf No. 154.20)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER J

Residential Distributed Generation Rate - Continued

(D) Base Rates (per month):

Rate I – Applicable to SC1 and SC9 Customers

(1) Base Usage Charges (per month):

Minimum Charge for the first 3 therms or less.........................	$31.30	per month
Over 3 therms...	101.50	cents per therm

(2) Minimum Charge (per month):

The Monthly Minimum Charge shall be the charge for the first 3 therms of gas.

(3) Merchant Function Charge, System Benefits Charge, and Billing and Payment Processing Charge:

A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, the System Benefits Charge, and the Billing and Payment Processing Charge as explained in General Information Section IX. A firm transportation Customer taking service under this rate is subject to the Billing and Payment Processing Charge and the System Benefits Charge as explained in General Information Section IX.

(4) Gas Cost Factor and Monthly Rate Adjustments:

A firm sales Customer taking service under this Rider is also subject to the Gas Cost Factor applicable to SC No. 1 of this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII. A firm transportation Customer taking service under this Rider is also subject to the Monthly Rate Adjustment as explained in Rate Provision (J)(1) of SC No. 9.

(5) Low Income Discount:

The Low Income Discount shall apply to customers enrolled in the Low Income Program under Rider E.

(General Information - Continued on Leaf No. 154.25)

GENERAL INFORMATION - Continued

VI. Service Classification Riders (Available on Request) - Continued

RIDER J

Residential Distributed Generation Rate - Continued

(D) Base Rates (per month) - Continued

Rate II -Applicable to SC 3 and SC9 Customers

(1) Base Usage Charges (per month)

Applicable to SC 3 and SC9 Customers in buildings with four or less dwelling units

Minimum Charge for the first 3 therms or less......................	$56.40	per month
Over 3 therms...	67.42	cents per therm

(2) Minimum Charge (per month):

The Monthly Minimum Charge shall be the charge for the first 3 therms of gas.

(3) Merchant Function Charge, System Benefits Charge, Billing and Payment Processing Charge and Weather Normalization Adjustment:

A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, the System Benefits Charge, the Billing and Payment Processing Charge, and the Weather Normalization Adjustment as explained in General Information Section IX. A firm transportation Customer taking service under this rate is subject to the Billing and Payment Processing Charge, the System Benefits Charge, and the Weather Normalization Adjustment as explained in General Information Section IX.

(4) Gas Cost Factor and Monthly Rate Adjustment:

A Firm Sales Customer taking service under this Rider is also subject to the Gas Cost Factor applicable to SC No. 3 of this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII. A firm transportation Customer taking service under this Rider is also subject to the Monthly Rate Adjustment as explained in Rate Provision (J)(1) of SC No. 9.

(5) Low-Income Discount:

The Low-Income Discount shall apply to customers enrolled in the Low-Income Program under Rider E.

(General Information - Continued on Leaf No. 154.26)

GENERAL INFORMATION – Continued

VII. Gas Cost Factor and Monthly Rate Adjustment

(A) Gas Cost Factor (GCF): The rates for gas service under SC Nos. 1, 2, 3 and 13 shall be increased each month by a Gas Cost Factor to reflect the Average Cost of Gas for the month, as adjusted by the following:
(1) Annual Surcharge or Refund Adjustment;
(2) Gas Supplier Take-or-Pay Charges;
(3) Pipeline Transition Costs; and

(B) A Monthly Rate Adjustment (MRA): The rates for gas service under SC Nos. 1, 2, 3 and 13, applicable Riders and equivalent firm transportation service under SC 9 will reflect the following:
(1) Non-Firm Revenue Credit;
(2) Other Monthly Rate Adjustment Components;
(i) Gas Facility Costs Credit Provision;
(ii) Reconciliation of Interference Costs;
(iii) Research & Development Surcharge;
(iv) Unbilled Fees Adjustment;
(v) Transition Adjustment for Competitive Services;
(vi) Low Income Reconciliation Adjustment;
(vii) Uncollectibles Charge Related to Monthly Rate Adjustment;
(viii) Gas in Storage Working Capital Charge;
(ix) Oil to Gas Conversion Program Surcharge;
(x) Curtailment Cost Recovery Charge;
(xi) Pipeline Facilities Adjustment;
(xii) Other Non-Recurring Adjustments;
(xiii) New York Facilities Adjustment;
(xiv) Gas Supplier Refunds;
(xv) Safety and Reliability Surcharge Mechanism (“SRSM”);
(xvi) Climate Change Vulnerability Study;
(xvii) Earnings Adjustment Mechanisms (“EAMs”) and Other Revenue Adjustments;
(xviii) Gas Demand Response Surcharge
(xix) Interconnection Plant Surcharge;
(xx) Surcharge for Gas Safety Compliance;
(xxi) Non- Pipes Alternatives (“NPA”) Adjustment;
(xxii) Gas Service Line Surcharge;
(xxiii) Reconciliation of Property Taxes; and
(xxiv) Uncollectible Bill Expense Adjustment.

(C) A Weather Normalization Adjustment.

The Gas Cost Factor and Monthly Rate Adjustment shall be expressed to the nearest 0.0001 of one cent.

(General Information - Continued on Leaf No. 155.1)

GENERAL INFORMATION – Continued

VII. Gas Cost Factor and Monthly Rate Adjustment – Continued

(A) Gas Cost Factor Components – Continued

1. Average Cost of Gas - Continued

(a) Fixed Gas Costs - Continued

The Company's apportioned share of fixed gas costs will be reduced by the following:

(i) Firm Customers' allocated share of the revenue derived from gas balancing services under SC No. 9 "Rates" (H) and (I), SC No. 12, and SC No. 20 "Charges" (A)-(C) and (F) and power generation as explained in General Information Section VII (B)1, as included in Non-Firm Revenues for Rate Years commencing prior to January 1, 2017;

(ii) the estimated fixed gas costs allocated to interruptible and off-peak firm customers taking service under SC Nos. 12 and 19;

(iii) Firm Customers' allocated share of net revenues derived from the use of interstate pipeline capacity for capacity releases which also includes capacity releases to firm transportation customers or to ESCOs serving firm transportation customers under the Company's Capacity Release Program, bundled sales and other off-system transactions, except for net revenues derived from the release of storage and firm transportation associated with storage related to periods commencing on or after November 1, 2017, as explained in General Information Section VII (B) 1; and

(iv) the credits to the Company received from storage field operators and pipeline companies with respect to payments received by them from Marketers and/or their Agents for the release of storage and capacity under Tier 2(B) – Physical Storage under the Company's Daily Delivery Service.

The Company's apportioned share of fixed gas costs, net of the foregoing reductions, will be further allocated between SC Nos. 1,2,3 and 13 according to the percentages set forth on the Statement of Gas Cost Factor and divided by the respective forecast quantities of gas to be taken for delivery to customers served under SC Nos. 1,2,3 and 13 for the twelve calendar months ending the following August 31. The Company will review the percentages used in allocating fixed costs between service classes at least annually. If such percentages change by +/- 1% or more, the Company will implement such changes in the Gas Cost Factor upon consultation with the Commission Staff.

(General Information - Continued on Leaf No. 157)

GENERAL INFORMATION – Continued

VII. Gas Cost Factor and Monthly Rate Adjustment - Continued

(A) Gas Cost Factor Components - Continued

1. Average Cost of Gas - Continued

(c) Total Average Cost of Gas

The total average costs of gas are the sum of the unit amounts determined in (a) and (b) above multiplied by a factor of adjustment to reflect distribution line losses, as further discussed in (d) below.

(d) Factor of Adjustment

The Factor of Adjustment (“FOA”) will be updated for each twelve-month period commencing January 1 based upon the average of the actual annual line loss factor (“LLF”) for the preceding five 12-month periods ending August 31 (“Five-Year Average”).

(General Information - Continued on Leaf No. 158)

GENERAL INFORMATION - Continued

VII. Gas Cost Factor and Monthly Rate Adjustment - Continued

(A) Gas Cost Factor Components - Continued

2. Annual Surcharge or Refund Adjustment:

Actual gas cost recoveries shall be reconciled with actual gas expenses each year, and a surcharge or refund to recover Gas Cost Factor under-recoveries or refund Gas Cost Factor over-collections shall be computed as follows:

(a) By taking the cost of gas adjusted for the following:
- (i) supplier refunds, if any, being credited to firm customers prior to February 1, 2017,
- (ii) firm customers' share of net revenues derived from the use of interstate pipeline capacity for capacity releases, bundled sales and other off-system transactions, except for net revenues derived from the release of storage and firm transportation associated with storage related to periods commencing on or after November 1, 2017,
- (iii) take-or-pay charges billed to the Company by its gas suppliers set forth in General Information Sections VII (A) 3 and IX.2, including gas pipeline transition costs set forth in General Information Section VII (A) 4,
- (iv) Winter Bundled Sales Service (WBSS) revenues from SC No. 20 Marketers for services rendered prior to March 1, 2017, on which date the WBSS was discontinued,
- (v) Managed Supply Service revenues prior to November 1, 2016 from SC No. 20 Marketers,
- (vi) firm customers' allocated share of balancing services revenues from SC No. 9 Rates (H) and (I), SC No. 12, and SC No. 20 "Charges" (A) - (C) and (F) and power generation, as included in Non-Firm Revenues for Rate Years commencing prior to January 1, 2017,
- (vii) liquefied propane consumed, as recorded on the Company's books during the determination period,
- (viii) the costs recorded during the determination period assignable to gas sold to Customers not subject to the Gas Cost Factor,
- (ix) any differences between the actual cost of baseload and peaking gas billed under Daily Delivery Service and the actual incurred cost of baseload and peaking gas utilized under the DDS Program, and
- (x) any differences between the estimated and actual incurred costs of capacity allocated to Marketers for Tier 2(A) –Virtual Storage Demand under the DDS program.

(General Information - Continued on Leaf No. 159)

GENERAL INFORMATION - Continued

VII. Gas Cost Factor and Monthly Rate Adjustment- Continued

(B) Monthly Rate Adjustment Components – Continued

2. Other Monthly Rate Adjustment Components

The Monthly Rate Adjustment shall be subject to the following other adjustments:

(i) Gas Facility Costs Credit Provision (for an explanation, see General Information Section IX.3);

(ii) Reconciliation of Interference Costs (for an explanation, see General Information Section IX.4);

(iii) Research & Development Surcharge (for an explanation, see General Information Section IX.5);

(iv) Unbilled Fees Adjustment (for an explanation, see General Information Section IX.6);

(v) Transition Adjustment for Competitive Services (for an explanation, see General Information Section IX.7);

(vi) Low Income Reconciliation Adjustment (for an explanation, see General Information Section IX.10);

(vii) Uncollectibles Charge Related to Monthly Rate Adjustment (for an explanation, see General Information Section IX.11);

(viii) Gas In Storage Working Capital Charge (for an explanation, see General Information Section IX.12);

(ix) Oil to Gas Conversion Program Surcharge; (for an explanation, see General Information Section IX.13);

(x) Curtailment Cost Recovery Charge (for an explanation, see General Information Section IX.15);

(xi) Pipeline Facilities Adjustment (for an explanation, see General Information Section IX.18);

(xii) Other Non-Recurring Adjustments (for an explanation, see General Information Section IX.19);

(xiii) New York Facilities Adjustment (for an explanation see General information Section IX.21);

(xiv) Gas Supplier Refunds (for an explanation see General Information Section IX.22);

(xv) Safety and Reliability Surcharge Mechanism (“SRSM”) (for an explanation see General Information Section IX.23);

(xvi) Climate Change Vulnerability Study (for an explanation see General Information Section IX.24);

(xvii) Earnings Adjustment Mechanisms (“EAMs”) and other Revenue Adjustments (for an explanation see General Information Section IX.25);

(xviii) Gas Demand Response Surcharge (for an explanation, see General Information Section IX.26);

(xix) Interconnection Plant Surcharge (for an explanation, see General Information Section IX.27);

(xx) Surcharge for Gas Safety Compliance (for an explanation, see General Information Section IX.28);

(General Information - Continued on Leaf No. 166.3)

GENERAL INFORMATION - Continued

VII. Gas Cost Factor and Monthly Rate Adjustment – Continued

(B) Monthly Rate Adjustment Components – Continued

2. Other Monthly Rate Adjustment Components - Continued

(xxi) Non-Pipes Alternatives ("NPA") Adjustment (for an explanation, see General Information Section IX.29);

(xxii) Gas Service Line Surcharge (for an explanation, see General Information Section IX.30);

(xxiii) Reconciliation of Property Taxes (for an explanation, see General Information Section IX.31); and

(xxiv) Uncollectible Bill Expense Adjustment (for an explanation, see General Information Section IX.32).

(C) Weather Normalization Adjustment

The rates for SC No. 2 - Rate II, SC No. 2 - Rate II Rider D, SC No. 3 and SC No. 3 Rider J Rate II shall be adjusted for the Weather Normalization Adjustment as explained in General Information Section IX. 1.

(D) Filing Requirements:

The Gas Cost Factor and Monthly Rate Adjustment will become effective on the first calendar day of the month following the computation date and continue in effect until changed. Such adjustments will be prorated based on the number of days each applicable adjustment is in effect during the billing period.

Not less than three (3) business days prior to any change in either the Gas Cost Factor or the Monthly Rate Adjustment, the Company will file with the Commission:

(a) a Statement of Gas Cost Factor showing the present Average Costs of Gas, the date at which and the period for which the average costs were determined, and the other rate adjustment components of the Gas Cost Factor, and the amount of the Gas Cost Factor per therm, together with the period such Gas Cost Factor per therm will remain in effect.

A new Statement of Gas Cost Factor may be filed on one day's notice to become effective not more than five days after the effective date of the initial statement if the replacement of cost estimates in the initial statement with actual figures results in a change in the Average Costs of Gas of more than five percent.

(b) a Statement of Monthly Rate Adjustment showing a summary of the rate adjustment components in General Information Section VII (B) comprising the Monthly Rate Adjustment, and the total amount of the Monthly Rate Adjustment per therm, together with the period such rate adjustment will remain in effect.

Such Statements will be available to the public at customer service centers where applications for service may be made.

(General Information - Continued on Leaf No. 167)

GENERAL INFORMATION - Continued

VIII. Increase in Rates Applicable in Municipality Where Service is Supplied - Continued

Statement of Percentage Increase in Rates and Charges - Continued

(A) - Continued

(2) - Continued

(d) Charges for Unauthorized Use

(e) The Value Added Charge component of the rate for Power Generation Transportation Customers

(3) The Merchant Function Charge

(4) The cost of gas included in the rates charged to interruptible gas customers taking service under SC No. 12 of this Rate Schedule, and

(5) The cost of gas included in the rates charged to customers taking service under SC No. 14 of this Rate Schedule.

(B) The Company's other charges are included in the General Information Section and in Miscellaneous Provisions (C) (5), (O) and (P) of SC No. 9, and Provisions (M) through (R) of SC No. 20 of this Rate Schedule. Late payment charges and security deposits are not included.

(C) Delivery rates and charges shall include a Billing and Payment Processing Charge, System Benefits Charge, and Revenue Decoupling Mechanism Adjustment as set forth in Section IX of the General Information Section of this rate schedule, as well as all other rates and charges, including the Monthly Rate Adjustment, as set forth in Section VII (B) of the General Information Section and in SC No. 9 of this Rate Schedule, the Weather Normalization Adjustment, as set forth in Section IX of the General Information Section of this Rate Schedule, and the Low Income Discount under Rider E. Late payment charges and security deposits are not included.

Revisions to the Statement of Percentage Increase in Rates and Charges will be made, if appropriate, in accordance with the procedure for other changes in the Statement, to reflect periodic reconciliations for actual tax expense incurred under all Sections of the New York Tax Law and the revenues collected to recover such tax expense.

When a new revenue tax or an increase in the rate of revenue taxes is enacted by a city or a village, the Company will file with the Public Service Commission a revised Statement, apart from this Rate Schedule, not less than fifteen business days before the date on which the Company proposes to increase the percentage increase in rates and charges, but no sooner than the date of the tax enactment to which the statement responds.

(General Information - Continued on Leaf No. 168)

GENERAL INFORMATION - Continued

IX. Special Adjustments

1. Weather Normalization Adjustment

A Weather Normalization Adjustment shall be effective for all Service Classification No. 3 sales Customers; for all Service Classification No. 2 sales Rate II Customers and for all firm transportation Customers otherwise eligible for Service Classification No. 3 or Service Classification No. 2 Rate II. The Weather Normalization Adjustment will be applied to total gas usage during the period October 1 through May 31 of each year. For transportation Customers, the Weather Normalization Adjustment is applied to the Customers' monthly sum of Daily Delivery Quantities during that period.

(A) Definitions

(1) PPBR or penultimate pure base rate is the next to last block rate set forth in Service Classification No. 3 (with the exception of Rate II of Rider J), in Rate II of Service Classification No. 2, and in Rate II of Rider D. For Rate II of Rider J, the PPBR is the rate for over 3 therms of usage.

(2) Pure base revenue is total revenue less revenue attributable to Increase in Rates and Charges, less Gas Cost Factor and Monthly Rate Adjustment revenue, and less revenue associated with the Merchant Function Charge, the System Benefits Charge, Billing and Payment processing Charge, Revenue Decoupling Mechanism Adjustment, and the Tax Sur-credit.

(3) BC or billing cycle is the actual number of days shown on the bill that the Customer receives for service.

(General Information - Continued on Leaf No. 172)

GENERAL INFORMATION - Continued

IX. Special Adjustments - Continued

1. Weather Normalization Adjustment - Continued

(B) Operation of the Weather Normalization Adjustment

The Weather Normalization Adjustment will be applied to a Customer's bill on a cents per therm basis when actual heating degree days vary from normal heating days during the period for which the Customer is billed. The Weather Normalization Adjustment will be applied to the Customer's total consumption and/or monthly sum of daily delivered quantities for the billing cycle except for air conditioning usage billed under the air conditioning rate. For Sales Customers, the Adjustment will be applied through the Monthly Rate Adjustment set forth in General Information Section VII (B). For Transportation Customers, the Weather Normalization Adjustment will be applied as explained in Service Classification No. 9. The Weather Normalization Adjustment for a billing cycle will apply only if the actual heating degree days (AHDD) for the billing cycle are lower or higher than the normal heating degree days (NHDD) for the billing cycle. A new weather adjustment factor will be calculated for each billing cycle for customers in Service Classification No. 2 Rate II, Service Classification No. 3, for Service Classification No. 3 Customers taking service under Rate II of Rider J, and for Service Classification No. 2 Rate II Customers taking service under Rider D. On a monthly basis, the Company will file with the Commission the Weather Normalization Adjustments for the twenty-one scheduled billing cycles for the month prior to such filing.

(General Information - Continued on Leaf No. 174)

GENERAL INFORMATION – Continued

IX. Special Adjustments - Continued

4. Reconciliation of Interference Costs

The Company will recover carrying charges associated with interference costs causing an exceedance of the gas net plant target. The interference costs will be recovered through a surcharge on the MRA statement, applicable to Firm Sales and Firm Transportation Customers.

(General Information - Continued on Leaf No. 177)

GENERAL INFORMATION - Continued

IX. Special Adjustments - Continued

5. Research and Development Surcharge Applicable to Firm Customers

In accordance with the Public Service Commission Order issued February 14, 2000 in Case 99-G-1369 and modified by Commission Order issued February 21, 2014 in Case 13-G-0031, all Firm Sales and Firm Transportation Customers will be subject to a research and development ("R&D") surcharge to provide funding for R&D projects.

6. Unbilled Fees Adjustment

The Company will recover or credit the reconciliation of all costs related to deferred late payment fees and other fees originally associated with customer non-payment (“Unbilled Fees”) for Rate Year One (i.e., 2020) as authorized by the Commission in Case 19-G-0066. The Company will recover these Unbilled Fees commencing December 1, 2021, through December 31, 2022. The Company will reconcile the approved fees in Rate Years Two (i.e., 2021) and Three (i.e., 2022) in Case 19-G-0066 without any threshold requirement and charge/credit any variance. The Company will begin its charge or credit of the approved fees for Rate Year Two on January 1, 2023, through December 31, 2023 and for Rate Year Three on January 1, 2024, through December 31, 2024. The Company will reconcile the actual annual late payment fee revenues with Commission approved levels included in base rates in 2023 and future years and charge/credit any variance over a subsequent twelve-month period as authorized by the Commission.

The Unbilled Fees Adjustment mechanism on the MRA statement is applicable to Firm Sales and Firm Transportation Customers. Any over- or under-recovery shall be included in a subsequent Unbilled Fees Adjustment.

(General Information - Continued on Leaf No. 178)

GENERAL INFORMATION - Continued

IX. Special Adjustments – Continued

7. Transition Adjustment for Competitive Services

The Transition Adjustment for Competitive Services ("TACS") is a per therm adjustment. Firm Sales customers taking service under Service Classification Nos. 1, 2, 3 and 13 and Riders D, H, and J of this Rate Schedule and Firm Transportation customers taking service under SC 9 will be assessed a TACS as set forth in the Monthly Rate Adjustment (MRA). The TACS will include lost revenues attributable to the Billing and Payment Processing Charge (BPP) which equals the total BPP charges avoided by retail choice customers receiving an ESCO-issued consolidated bill. Prior to January 1, 2019, the TACS also included any variation between the level of Credit and Collections/theft (“C&C”) revenues applicable to POR customers and included in the POR Discount Percentage, and actual C&C revenues received thorough the POR Discount Percentage (“C&C Variation”). Effective January 1, 2019 this C&C Variation, and any prior period reconciliations, will be reflected in the Credit and Collection component of the POR Discount Percentage as described in Miscellaneous Provision (P) under Service Classification No. 20.

(General Information - Continued on Leaf No. 178.1)

GENERAL INFORMATION – Continued

IX. Special Adjustments – Continued

7. Transition Adjustment for Competitive Services – Continued

For Service Classification Nos. 1, 2, 3 and 13, and for SC No. 9 firm transportation, the TACS shall be determined by dividing the BPP lost revenues for each rate year beginning January 1 by the total of firm full service and transportation therms for the twelve-month period for which the TACS is to be effective. The TACS that commences each January will be in effect for a 12-month period and will be based on the 12 months ending December of the prior year.

Each TACS will include any reconciliation amounts from the TACS in effect for prior periods and prior period deferrals. The reconciliation amount is the difference between the amount to be recovered through the TACS and the actual amount recovered through the TACS, plus interest (calculated at the Other Customer Capital Rate).

8. Merchant Function Charge (MFC)

The Merchant Function Charge (MFC), for each Service Classification and (applicable Riders) consists of the following components:

(a) a Supply component, which includes commodity procurement (including commodity revenue based allocation of information resources and education and outreach costs);

(b) a credit and collections/theft ("C&C") component; and

(c) an uncollectible expense component associated with supply.

The MFC will be charged monthly to Firm Full Service Customers served under SC 1, 2, 3 and 13. The cents per therm rates differ by residential and non-residential service classes and are applicable to the supply-related and credit and collection-related components of the MFC.

(General Information - Continued on Leaf No. 178.2)

GENERAL INFORMATION – Continued

IX. Special Adjustments – Continued

8. Merchant Function Charge (MFC) – Continued

The MFC Supply and MFC C&C rates (shown below) are based on Commission approved design targets and are exclusive of any prior period reconciliation. The residential rates apply to SC 1 and SC3 and the non-residential rates apply to SC 2 and SC 13.

(cents/therm)	MFC Supply	MFC C&C
Residential	0.7437	0.9216
Non-Residential	0.3956	0.3029

The uncollectible expense component will be aligned with service classes consistent with the monthly Gas Cost Factors (GCF) and will reflect uncollectible factors of $0.7200 per $100 of commodity costs for residential customers and $0.2800 per $100 of commodity costs for non-residential customers.

For each twelve month period commencing January 1 (Rate Year), amounts collected through the Supply component and the C&C component of the MFC will be reconciled to the design targets established for the Rate Year. Any differences will be included in the Supply and C&C components of the MFC in the subsequent Rate Year.

The Company shall file with the Public Service Commission (“PSC”) a monthly statement of the Merchant Function Charge (“MFC Statement”). Each component of the MFC will be shown separately by Service Class (i.e., SC 1, 2 Rate I, 2 Rate II, 3 and 13). Separate Merchant Function Charges shall be filed for air-conditioning customers served under SC2 Rate II and SC3. Each MFC Statement shall be filed with the PSC no later than two working days prior to the effective date of the statement.

(General Information - Continued on Leaf No. 179)

GENERAL INFORMATION – Continued

IX. Special Adjustments – Continued

9. Billing and Payment Processing (BPP) - Continued

C. Dual Service (Gas and Electric) – Gas BPP and Gas ESCO charges for accounts with each service served by a different ESCO

	Electric Service Type	Gas Retail Choice Utility Single Bill (POR)	Gas Retail Choice Two Bills	Gas Retail Choice ESCO Single Bill
Gas Customer	Electric Retail Choice Utility Single Bill (POR)	$0.00	$0.00	N/A
Gas ESCO	Electric Retail Choice Utility Single Bill (POR)	$0.64**	$0.00*	N/A
Gas Customer	Electric Retail Choice Two Bill	$0.00	$0.64***	$0.00
Gas ESCO	Electric Retail Choice Two Bill	$1.28	$0.00	$0.00
Gas Customer	Electric Retail Choice ESCO Single Bill	N/A	$0.00	N/A
Gas ESCO	Electric Retail Choice ESCO Single Bill	N/A	$0.00	N/A

*The electric ESCO will pay $1.28.
**The electric ESCO will also pay $0.64.
***The Customer, as an electric customer, will also pay $0.64.

10. Low Income Reconciliation Adjustment

All Firm Sales and Firm Transportation Customers shall be subject to an annual Low Income Reconciliation Adjustment each twelve month period commencing January 1 (Rate Year) for (1) any difference between the amount of Low Income Discounts embedded in rates ($35.393 million) and the actual level of Low Income Discounts provided during such twelve-month period, and (2) any reconnection fees waived, in accordance with General Information Section III.8.(V). The adjustment shall be calculated on a cents per therm basis, and shall be credited or surcharged to SC 1, 2, 3 and 13 firm sales customers and corresponding SC 9 firm transportation customers, including Low Income Customers, as an adjustment to the MRA. The adjustments will become effective the following January 1 for a twelve-month period.

(General Information - Continued on Leaf No. 181)

GENERAL INFORMATION - Continued

IX. Special Adjustments - Continued

11. Uncollectibles Charge

The Company will recover an Uncollectibles Charge associated with the MRA as a monthly surcharge to the MRA. The Uncollectibles Charge will reflect an overall uncollectible rate of 0.46%.

12. Gas In Storage Working Capital Charge

Prior to November 1, 2016, the Company recovered Gas in Storage Working Capital costs through the MRA and MFC. For each twelve month period starting November 1, 2016, the Company will recover Gas in Storage Working Capital costs through the MRA. The carrying charges used in the determination of storage working capital costs will be the Company's authorized pre-tax rate of return on the base storage level and the Commission's Other Customer Capital Rate on amounts above the base storage level. The base storage level is defined as the lowest monthly balance. For purposes of calculating the rate to be billed to customers for each year, the base and above base storage levels will be estimated based on the prior year’s actual levels. Effective November 1, 2016, Gas in Storage Working Capital costs will be allocated to Firm Sales and Firm Transportation Customers based on the percentage used to allocate the Company’s assets between Firm Sales and Firm Transportation Customers as described in SC 20 – Operational Matters (C)(1) – Daily Delivery Service, adjusted to exclude assets allocated to Marketers under Tier 2(B) of the Company’s Daily Delivery Service. Any over- or under collection of Gas in Storage Working Capital costs for the ten months ending October 2016 will be included in the MRA for the twelve months beginning November 1, 2016. Any such reconciliation for the period ending October 2016 will be allocated to sales and transportation customers using the same methodology employed to allocate these costs for the ten months ending October 2016. For each twelve-month period commencing November 1 actual Gas in Storage Working Capital costs will be reconciled with actual Gas in Storage Working Capital recoveries derived through the MRA, and any over- or under-recovery shall be refunded or recovered through the Gas in Storage Working Capital components of the MRA during the subsequent twelve-month period commencing November 1.

13. Oil to Gas Conversion Program Surcharge

Effective January 1, 2020, the Company’s Oil Heating to Gas Heating Conversion Incentive Program is discontinued.

Until fully recovered, the Company will recover, through a surcharge on the MRA Statement, up to $1.465 million spent during each Rate Year through December 31, 2019, for the cost of providing to customers incentives associated with the Company’s Oil Heating to Gas Heating Conversion Incentive Program.

(General Information - Continued on Leaf No. 181.1)

GENERAL INFORMATION - Continued

IX. Special Adjustments - Continued

14. Revenue Decoupling Mechanism ("RDM") Adjustment

For each year commencing January 1 ("Rate Year") Delivery Revenue from firm gas sales customers served under Service Classification ("SC") Nos. 1, 2 and 3 and from firm transportation customers taking service under SC 9 who would otherwise have taken service under SC 1, SC 2 or SC 3, will be subject to a reconciliation through a Revenue Decoupling Mechanism ("RDM") Adjustment, as described below. For purposes of the RDM adjustment, Delivery Revenue is defined as revenue derived from the base tariff rates applicable to SC 1, 2 and 3, and from the associated SC9 firm transportation tariff rates and weather normalization credits and surcharges. The RDM applies to the following customer groups, including all customers taking service under SC 9 that would have taken service under such group:

SC No. 1;
SC No. 2 – Rate I;
SC No. 2 – Rate II;
SC No. 3 customers with 1-4 dwelling units; and
SC No. 3 customers with more than 4 dwelling units;

The groups will also include, as applicable, (1) all gas volumes associated with customers receiving air conditioning service under SC 2 and 3; (2) the usage up to and including the Baseline Billing Determinants for customers taking service under Rider D (Excelsior Jobs Program); and (3) SC 1 and SC 3 customers participating in the Low Income Program. The groups will exclude (1) customers taking service under Rider H (Distributed Generation Rate) and Rider J (Residential Distributed Generation Rate); (2) customers receiving service under firm by-pass rates; and (3) the usage above the Baseline Billing Determinants for customers taking service under Rider D.

For each customer group subject to the RDM, the Company will, at the end of each Rate Year, make an RDM adjustment to the extent that Actual Delivery Revenue varies from Allowed Delivery Revenue. Actual Delivery Revenue is the total of the Rate Year's revenue derived from the base tariff rates applicable to SC 1, 2 and 3, and from the associated SC 9 firm transportation tariff rates, and weather normalization credits or surcharges, but excluding revenues derived from the RDM adjustment as described below. Actual Delivery Revenue will be adjusted to add, for the first month that new base rates go into effect in each Rate Year, the effect of proration between old and new rates.

(General Information - Continued on Leaf No. 181.2)

GENERAL INFORMATION - Continued

IX. Special Adjustments - Continued

14. Revenue Decoupling Mechanism ("RDM") Adjustment - Continued

Allowed Delivery Revenue (in $000's), by customer group, is as follows:

	Jan. – Dec. 2023*
SC No. 1	TBD
SC No. 2 – Rate I	TBD
SC No. 2 – Rate II	TBD
SC No. 3 – 1 to 4 dwelling units	TBD
SC No. 3 – more than 4 dwelling units	TBD

* Allowed Delivery Revenue for each rate year thereafter will continue at these amounts unless and until changed.

Any resulting RDM adjustment will be surcharged or refunded through separate per therm adjustments applicable to each customer group. Should the amount of any adjustment be less than 0.0001 cents per therm, the Company reserves the right to calculate the adjustment for a shorter time period or to defer the adjustment to a future period. Except as described below, the RDM Adjustment for each group will become effective in the second calendar month following the end of the twelve month period for which the RDM adjustment is calculated and will be recovered over a twelve month period. RDM adjustments by group will be shown on the Statement of Revenue Decoupling Mechanism Adjustment. The Company will file such Statement with the Public Service Commission no less than two working days prior to the start of each twelve-month period that the RDM Adjustment is to be in effect (and no less than two working days prior to any change in the RDM Adjustment as set forth herein).

All refunds or surcharges billed to customers through the RDM adjustments shall be subject to reconciliation at the end of each reconciliation period.

Beginning with the first month of each Rate Year, interest at the Other Customer Provided Capital Rate will be calculated for each month on the average of the current and prior month's cumulative revenue over- or under-collection (net of state and federal taxes) and will be included along with the over- or under-collection charged or credited to customers.

The Company may implement an Interim RDM Adjustment whenever the Company determines that such an adjustment is necessary to avoid a large over- or under- collection, based on the Company's projection for that Rate Year of forthcoming RDM reconciliation balances. Any Interim RDM Adjustment will be determined based on a twelve-month recovery period and resulting higher or lower revenues will be included in the annual RDM reconciliation.

(General Information - Continued on Leaf No. 182)

GENERAL INFORMATION - Continued

IX. Special Adjustments-Continued

16. System Benefits Charge ("SBC") - Continued

B. Energy Efficiency ("EE") Tracker Surcharge Rate

The EE Tracker Surcharge rate collects: (1) annual authorized collections starting 2016 associated with Company-run energy-efficiency programs, excluding programs funded through base delivery rates; and (2) starting 2017, any prior period over- or under-collections for these programs, minus interest earned on prior-period surcharges for these programs calculated at the Other Customer Capital Rate.

Each surcharge rate will be calculated by dividing the necessary collection amount by the projected firm therm deliveries for the period in which the Statement is to be in effect.

17. Reserved For Future Use

(General Information - Continued on Leaf No. 183.1)

GENERAL INFORMATION – Continued

IX. Special Adjustments-Continued

18. Pipeline Facilities Adjustment

The Pipeline Facilities Adjustment will recover Commission approved payments made to interstate pipeline companies for upgrades to interstate pipeline facilities at the Company's gate stations. The recovery will include interest at the Commission's Other Customer Capital Rate. The Pipeline Facilities Adjustment will be a per therm adjustment recovered over twelve months and surcharged to Firm Sales and Firm Transportation Customers, at the same rate, commencing after each project's in-service date. Any over- or under-recovery shall be included in a subsequent Pipeline Facilities Adjustment. Should the amount of any adjustment be less than 0.0001 cents per therm, the Company reserves the right to calculate the adjustment for a shorter time period. Any amounts incurred over the Commission approved levels shall be deferred and addressed in the Company's next base rate proceeding.

19. Other Non-Recurring Adjustments

Monthly Rate Adjustments ("MRA") applicable to Firm Sales and Firm Transportation Customers shall be used to charge or credit customers for any Non-Recurring Adjustments as directed by the Commission. Any future non-recurring adjustments ordered by the Commission to be adjusted through the MRA shall be included as a separate line item in the MRA.

(General Information - Continued on Leaf No. 183.2)

GENERAL INFORMATION - Continued

IX. Special Adjustments - Continued

20. Reserved For Future Use

21. New York Facilities Adjustment

Firm Sales and Firm Transportation Customers shall be subject to the New York Facilities Adjustment for any differences between the Company's share of the New York Facilities revenues and costs embedded in base delivery rates, pursuant to the Rate Plan approved in Case 19-G-0066, and the Company's actual costs and revenues resulting from the New York Facilities Agreement among the Company, The Brooklyn Union Gas Company d/b/a National Grid NY ("Brooklyn Union"), and KeySpan Gas East Corporation d/b/a National Grid ("Gas East")

The New York Facilities Adjustment shall be calculated on a cents per therm basis, and shall be credited or surcharged to Firm Sales and Firm Transportation Customers, at the same rate, as an adjustment to the MRA.

(General Information - Continued on Leaf No. 183.3)

GENERAL INFORMATION – Continued

28. Surcharge for Gas Safety Compliance

The Company will recover carrying charges, including depreciation, associated with incremental capital and O&M costs incurred to comply with federal, state and/or local gas safety-related laws, rules and/or regulations, pursuant to Commission approval. The costs will be recovered through a surcharge on the MRA statement, applicable to Firm Sales and Firm Transportation Customers, until such costs are incorporated into base rates.

29. Non-Pipes Alternatives ("NPA") Adjustment

The Company will recover costs associated with the implementation of NPAs, including the overall pre-tax rate of return on such costs, and any applicable incentives. To the extent such new NPAs result in the Company displacing a capital project reflected in the Average Gas Plant In Service Balances, the balances will be reduced to exclude the forecasted net plant costs associated with the displaced project, the carrying charge on the reduction will be applied as a credit against the NPA, pursuant to Commission Order in Case 19-G-0066. The costs will be recovered through a surcharge on the MRA statement, applicable to Firm Sales and Firm Transportation Customers, until such costs are incorporated into base rates.

The Company will recover the following costs associated with its District Energy Initiative pursuant to Commission Order in Case 19-G-0066: a) implementation costs associated with the initial location of the District Energy Initiative Pilot Program; and b) costs related to consulting fees for studies and reports, capped at $1.5 million. The costs will be recovered through a surcharge on the MRA statement, applicable to Firm Sales and Firm Transportation Customers.

30. Gas Service Line Surcharge

The Company will recover costs associated with Gas Service Line survey/inspection costs incurred above those included in base rates, pursuant to Commission Order in Case 19-G-0066. The recovery is capped at $99.79 million for the term of the Rate Plan. Any revenues generated by fees associated with the survey/inspection process will be a credit to customers.

The costs will be recovered through a surcharge on the MRA statement, applicable to Firm Sales and Firm Transportation Customers.

31. Reconciliation of Property Taxes

The Company will charge or credit Customers the difference between actual annual property taxes and Commission approved levels in base rates. The Reconciliation of Property Taxes shall be credited or charged to Firm Sales and Firm Transportation Customers, at the same rate, as an adjustment to the MRA.

(General Information - Continued on Leaf No. 183.7)

GENERAL INFORMATION – Continued

32. Uncollectible Bill Expense Adjustment

The Company will recover the difference, plus interest, between the actual annual uncollectible expense and Commission approved levels in rates for the period January 1, 2020 through December 31, 2025. After that time, the Company may recover any under-collections. Additionally, a charge or credit will be included for the reconciliation of the non-Credit and Collections related portion of the POR Discount reconciliation

The costs will be recovered through a surcharge or credit on the MRA statement, applicable to Firm Sales and Firm Transportation Customers.

(General Information – Continued on Leaf No. 184)

SERVICE CLASSIFICATION NO. 1 - Continued

RESIDENTIAL AND RELIGIOUS FIRM SALES SERVICE

Availability of Service – Continued

General

Base Rate (per month)

Applicability:

To all Customers served under this Service Classification:

For the first	3	therms (or less)	$31.00
For excess over	3	therms	317.07 cents per therm

Minimum Charge (per month):
The Monthly Minimum Charge shall be the charge for the first 3 therms of gas.

Merchant Function Charge, Billing and Payment Processing Charge, System Benefits Charge, and the Revenue Decoupling Mechanism Adjustment:
A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, Billing and Payment Processing Charge, System Benefits Charge, and the Revenue Decoupling Mechanism Adjustment as explained in General Information Section IX.

Low Income Discount:
The Low Income Discount shall apply to customers enrolled in the Low Income Program under Rider E.

(Service Classification No. 1 - Continued on Leaf No. 229)

SERVICE CLASSIFICATION NO. 2

GENERAL FIRM SALES SERVICE

Availability of Service

Any use of gas by any Customer except where the Customer is eligible for service under Service Classifications Nos. 1, 3, or 14 subject to the requirements of this Service Classification, the Company's Sales and Transportation Operating Procedures, and the other applicable provisions of this Rate Schedule, provided however, that religious organizations, community residences that are supportive living facilities or supervised living facilities, and veterans' posts or halls eligible for service under SC 1 or 3 may elect to take service under this Service Classification.

Applicability

Beginning in May 2018 and each May thereafter, customers taking service under this Service Classification will be subject to annual reviews to determine eligibility under Rate I or Rate II. Each customer will be assigned a ratio representing the relationship between their average daily use for the months of January through March and their average daily use for the months of July through September. Any Rate I customer whose ratio exceeds 2.2 at the time of the annual review will be transferred to Rate II effective with their next bill. Any Rate II customer whose ratio falls below 1.8 will be transferred to Rate I effective with their next bill.

Effective with bills having a "from" date on or after February 1, 2017, the ratio methodology described above will be used to determine a customer's eligibility for Rate I or Rate II. This initial determination will be based on each customer's ratio calculated based on usage for the periods July through September 2014 and January through March 2015.

For the purposes of the ratio calculation described above, the last day of usage in a customer's billing period that occurs in the months of January through March and July through September will determine the month to which that usage is assigned.

Exceptions to this ratio calculation can be found in General Provision (D) of this Service Classification.

Rate I (per month)
Base Rate

For the first	3	therms (or less)	$44.90	
For the next....................................	87	therms	117.78	cents per therm
For the next....................................	2,910	therms	66.27	cents per therm
For excess over..............................	3,000	therms	49.20	cents per therm

Rate II (per month)
Base Rate

For the first	3	therms (or less)	$44.90	
For the next	87	therms	125.07	cents per therm
For the next....................................	2,910	therms	97.80	cents per therm
For excess over..............................	3,000	therms	71.38	cents per therm

(Service Classification No. 2 - Continued on Leaf No. 231)

SERVICE CLASSIFICATION NO. 2 - Continued

GENERAL FIRM SALES SERVICE

Rate Provisions Applicable to Rate I and Rate II - Continued

Minimum Charge Applicable to Large Dual-Fuel Customers - Continued

2. Reconciliation of Minimum Charge

If a dual-fuel Customer has taken less than the minimum usage for which the Customer was charged in any month or months (shortfall months), there shall be an annual reconciliation between the minimum usage for which the Customer was responsible throughout the previous 12-month period and the actual quantity of service taken by the Customer under this Service Classification during that period. The reconciliation shall take place at twelve month intervals following the date the Customer is first subject to this minimum charge. If the Customer's actual consumption during the 12-month period as a whole was equal to or greater than two-thirds of 100,000 therms the Company will refund all minimum charges paid in the shortfall months in excess of the amounts applicable to the actual quantity of service taken in those months. If the Customer's actual use during the 12-month period was less than two-thirds of 100,000 therms the Company may refund any amounts paid in excess of the Customer's minimum charge for the year. However, in no event shall the customer be charged less than the amount based on their actual consumption during the 12-month period.

(Service Classification No. 2 - Continued on Leaf No. 233)

SERVICE CLASSIFICATION NO. 2 - Continued

GENERAL FIRM SALES SERVICE

Rate Provisions Applicable to Rate I and Rate II - Continued

Air Conditioning Rate

Customers who use gas for the operation of gas air-conditioning equipment which is permanently installed will be billed for gas used during the period June 14th to October 14th as follows (per meter per month):

(1) The total quantity of gas supplied, less the quantity of gas billed at the air-conditioning rate set forth below, will be billed at the rates under Rate I or Rate II, whichever is applicable;

(2) The quantity of gas (if any) exceeding 12 therms, and up to a maximum of 62 therms per ton of rated capacity of the Customer's air-conditioning equipment, will be billed at the rate set forth below.

For the first	1,200 therms	60.29	cents per therm
For excess over	1,200 therms	51.57	cents per therm

When a bill includes periods during both the Air-Conditioning Billing Period (June 14th to October 14th) and the Standard Billing Period (balance of the year), the rates and charges applicable will be prorated based on the number of days in the Air-Conditioning Billing Period and the number of days in the Standard Billing Period related to the total number of days in the billing period.

(Service Classification No.2 - Continued on Leaf No. 235)

SERVICE CLASSIFICATION NO. 2 - Continued

GENERAL FIRM SALES SERVICE

Rate Provisions Applicable to Rate I and Rate II – Continued

Increase in Rates and Charges

The rates and charges under this Service Classification shall be increased by the applicable percentage shown on the "Statement of Percentage Increase in Rates and Charges" (for an explanation, see General Rule VIII "Increase in Rates Applicable in Municipality Where Service is Supplied").

Merchant Function Charge, Billing and Payment Processing Charge, System Benefits Charge, Revenue Decoupling Mechanism Adjustment, and Weather Normalization Adjustment

A Firm Sales Customer taking service under this Service Classification is also subject to the Merchant Function Charge, the Billing and Payment Processing Charge, the System Benefits Charge, Revenue Decoupling Mechanism Adjustment, and for Rate II Customers only, the Weather Normalization Adjustment as explained in General Information Section IX.

Gas Cost Factor and Monthly Rate Adjustment

A firm sales Customer taking service under this Service Classification is also subject to the Gas Cost Factor applicable to this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII.

General Provisions

(A) Additional provisions relating specifically to the service supplied under this Service Classification are set forth in the section "General Information Applicable to Firm Sales Service" starting on Leaf No. 250.

(B) For general rules, regulations, terms, and conditions under which gas service will be supplied, see General Information sections I through XI, inclusive.

(C) Gas will not be supplied for submetering to any owner, tenant, or occupant of the building or premises unless the Customer has applied for and received a waiver from the New York Public Service Commission permitting the Customer to submeter gas to the non-residential tenants or occupants of that building or premises.

(D) The ratio calculation described in Applicability above is subject to the following exceptions:

(1) Customers taking service under Rider H – Distributed Generation Rate will not be subject to the annual review. All Rider H customers will pay the various surcharges and adjustments described in Rider H, applicable to Rate I of this Service Classification.

(2) New Customers commencing service under this Service Classification will initially be placed on Rate I or Rate II based on their load letter and application for service (for new service requests) or based on the previous tenant’s rate (for previously occupied premises). Any such new Customer will remain on this rate until a subsequent annual review.

(Service Classification No.2 - Continued on Leaf No. 235.1)

SERVICE CLASSIFICATION NO. 2 - Continued

GENERAL FIRM SALES SERVICE

General Provisions – Continued

(D) – Continued

(3) Customers with limited or incomplete billing history, such as new Customers (as described above), will remain at their initial rate until a subsequent annual review.

(4) Customers with bills or re-bills spanning several months will be excluded from the annual review, and remain on their existing rate, if the average number of monthly billing days (*i.e.*, total billing days associated with billed usage in the season divided by 3) in either season is greater than 45.

(5) Oil-to-gas conversion customers with gas meter turn-on dates later than the October 1 immediately preceding the annual review will be excluded and remain at their initial rate until a subsequent annual review.

(Service Classification No.2 - Continued on Leaf No. 236)

SERVICE CLASSIFICATION NO. 3 - Continued

RESIDENTIAL AND RELIGIOUS - HEATING FIRM SALES SERVICE

Heating

Base Rate (per month)

Applicability:

To all Customers served under this Service Classification:

For the first	3	therms (or less)	$31.00
For the next	87	therms	156.91 cents per therm
For the next	2,910	therms	124.27 cents per therm
For excess over	3,000	therms	100.39 cents per therm

Minimum Charge (per month)
The Monthy Minimum Charge shall be the charge for the first 3 therms of gas, except for Customers with dual-fuel facilities that are subject to the minimum charge set forth below.

Minimum Charge Applicable to Large Dual-Fuel Customers

(1) Minimum Charge:
A dual-fuel Customer commencing service hereunder whose estimated Annual Allocation is equal to or exceeds 100,000 therms will be subject to a monthly minimum charge. In addition, a monthly minimum charge will be applied to a Customer that converts from gas only burning equipment to dual-fuel capable equipment after commencing service hereunder and whose estimated Annual Allocation or actual annual use, whichever is greater, is equal to or exceeds 100,000 therms per year, beginning with the second billing month following such determination by the Company.

(Service Classification No. 3 - Continued on Leaf No. 241)

SERVICE CLASSIFICATION No. 3 - Continued

RESIDENTIAL AND RELIGIOUS - HEATING FIRM SALES SERVICE

Minimum Charge Applicable to Large Dual-Fuel Customers – Continued

(1) Minimum Charge – Continued

The Customer's Annual Allocation is the Customer's estimated annual gas requirements on record with the Company.

The monthly minimum charge shall be determined by applying the delivery rates (and/or air-conditioning rates, as applicable) for this Service Classification, whichever is applicable, to two-thirds of 100,000 therms divided by 365 days multiplied by the number of days (approximately 30) in the billing period.

(2) Reconciliation of Minimum Charge:

If a dual-fuel Customer has taken less than the minimum usage for which the Customer was charged in any month or months (shortfall months), there shall be an annual reconciliation between the minimum usage for which the Customer was responsible throughout the previous 12-month period and the actual quantity of service taken by the Customer under this Service Classification during that period. The reconciliation shall take place at twelve-month intervals following the date the Customer is first subject to this minimum charge. If the Customer’s actual consumption during the 12-month period was equal to or greater than two-thirds of 100,000 therms, the Company will refund all minimum charges paid in the shortfall months in excess of the amounts applicable to the actual quantity of service taken in those months. If the Customer’s actual use during the 12-month period was less than two-thirds of 100,000 therms, the Company may refund any amounts paid in excess of the Customer’s minimum charge for the year. However, in no event shall the customer be charged less than the amount based on their actual consumption during the 12-month period.

(Service Classification No. 3 - Continued on Leaf No. 242)

SERVICE CLASSIFICATION NO. 3 - Continued

RESIDENTIAL AND RELIGIOUS - HEATING FIRM SALES SERVICE

Air-Conditioning Rate

Customers who use gas for the operation of gas air-conditioning equipment which is permanently installed will be billed for gas used during the period June 14th to October 14th as follows (per meter per month):

(1) The total quantity of gas supplied, less the quantity of gas billed at the air-conditioning rate set forth below, will be billed at the rates under this service classification.

(2) The quantity of gas (if any) exceeding 12 therms, and up to a maximum of 62 therms per ton of rated capacity of the Customer's air-conditioning equipment, will be billed at the rate set forth below.

For the first	1,200 therms	60.29	cents per therm
For excess over	1,200 therms	51.57	cents per therm

When a bill includes periods during both the Air-Conditioning Billing Period (June 14th to October 14th) and the Standard Billing Period (balance of the year), the rates and charges applicable will be prorated based on the number of days in the Air-Conditioning Billing Period and the number of days in the Standard Billing Period related to the total number of days in the billing period.

Increase in Rates and Charges:

The rates and charges under this Service Classification shall be increased by the applicable percentage shown on the "Statement of Percentage Increase in Rates and Charges" (for an explanation, see General Rule VIII "Increase in Rates Applicable in Municipality Where Service is Supplied").

Merchant Function Charge, Billing and Payment Processing Charge, System Benefits Charge, Revenue Decoupling Mechanism Adjustment, andWeather Normalization Adjustment:

A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, Billing and Payment Processing Charge, the System Benefits Charge, Revenue Decoupling Mechanism Adjustment, and the Weather Normalization Adjustment as explained in General Information Section IX.

Gas Cost Factor and Monthly Rate Adjustment:
A firm sales Customer taking service under this rate is also subject to the Gas Cost Factor applicable to this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII.

Low Income Discount
The Low Income Discount shall apply to customers enrolled in the Low Income Program under Rider E.

(Service Classification No. 3 - Continued on Leaf No. 244)

General Information Applicable to Firm Sales Services - Continued

(E) Riders:

The following riders may be applied to service supplied under the service classifications described below or in the body of the applicable riders:

Rider A - "Continuance of Agreement for Service by Receiver, Trustee, or Like Officer of Court" - Service Classification Nos. 1, 2, 3, 9, 12, 13, and 14 (for an explanation of Rider A, see Leaf No. 119).

Rider B - "Conjunctional Billing" - Service Classification Nos. 2 and 3, to religious institutions under Service Classification No. 1, and to veterans' organizations which were receiving service under this Rider when transferred to Service Classification No. 1 (for an explanation of Rider B, see Leaf No. 121).

Rider C - "Intercommunicating Buildings" - Service Classification Nos. 2 and 3 and religious institutions under Service Classification No. 1, and to veterans' organizations which were receiving service under this Rider when transferred to Service Classification No 1 (for an explanation of Rider C, see Leaf No. 123).

Rider D - “Excelsior Jobs Program” – Service Classification Nos. 2 and 9 (for an explanation of Rider D, see Leaf No. 125).

Rider E - “Low Income Program” – Service Classification Nos. 1, 3 and 9 (see General Information Section VI).

Rider F - RESERVED FOR FUTURE USE

Rider G - RESERVED FOR FUTURE USE

Rider H - “Distributed Generation Rate” (for an explanation of Rider H, see Leaf No. 154.1).

Rider I - RESERVED FOR FUTURE USE

Rider J - “Residential Distributed Generation Rate”(for explanation of Rider J, see Leaf No. 154.20)

(F) Application Forms:

For form of application for residential and religious and non-residential Customers applying for service under Service Classification Nos. 1, 2 and 3, see Leaf Nos. 185-190.

(General Information Applicable to Firm Sales Services - Continued on Leaf No. 252)

SERVICE CLASSIFICATION NO. 9 - Continued

TRANSPORTATION SERVICE (TS) - Continued

Table of Contents - Continued

Rates - Continued

(Service Classification No. 9 - Continued on Leaf No. 256)

SERVICE CLASSIFICATION NO. 9 - Continued

Transportation Service - Continued

Definitions - Continued

(5) **Citygate** means a point of interconnection between the facilities of (i) an interstate pipeline or Local RNG Production, and (ii) the local facilities through which the Company receives deliveries from that pipeline or Local RNG Production.

(5a) **Contract Interruptible or Off-Peak Firm Industrial Customer** means an Interruptible or Off-Peak Firm Customer taking service under a negotiated contract whose actual or estimated annual gas usage exceeds 3,000,000 therms and who demonstrates that 75% or more of its annual gas usage is used directly for manufacturing; Manufacturing for purposes of this Service Classification is a Customer whose facilities would be classified as Manufacturing (Division D) by the Standard Industrial Manual (1987 ed. as supplemented). Gas usage in manufacturing-related space includes usage in areas used for manufacturing, product design space, raw material storage, finished product storage, product packaging and shipping, mechanical equipment rooms, back-up machine and equipment storage. Gas usage in all other areas, including cafeteria, sales and accounting offices, common halls and lavatories does not qualify as manufacturing-related usage.

(6) **Converting Customer** means a Service Classification ("SC") 1, SC 2 Rate I, SC 2 Rate II, or SC 3 Customer electing Firm Transportation Service after taking service for a minimum of one year under SC 1, 2, or 3. A Customer who commences service under SC 1, 2, or 3 may convert to Firm Transportation Service within 60 days of commencement of service.

(7) **Customer** means a single account that may also be a member of a Small Customer Aggregation Group.

(8) **Daily Transportation Quantity** means the confirmed scheduled quantity of gas delivered to the Receipt Point for the Customer's account on any day, including gas purchased from the Company by a SC No. 20 Marketer under the Company's Daily Delivery Service in accordance with the provisions set forth under SC No. 20. Any adjustments to storage deliveries to account for actual weather pursuant to the Intraday Balancing rules set forth in the Company's GTOP will not be reflected in the Daily Transportation Quantity. The Daily Transportation Quantity shall be increased by an amount to be retained as an allowance for losses. For an aggregated group of two or more customers, the Seller is required to submit to the Company one scheduled quantity of gas representing deliveries to all customers in the group. The line loss adjustment factor is set forth on the monthly Statement of Rate for Service Classification No. 9.

(9) **Daily Delivery Quantity** means the quantity delivered by the Company to the Customer's meter and consumed by the Customer on any day.

(9a) **Daily Delivery Service Quantity** means the quantity of gas that the Marketer is required to deliver to the Company's Citygate Receipt Points based upon the temperature-dependent equation found in the Company's GTOP.

(Service Classification No. 9 - Continued on Leaf No. 260)

SERVICE CLASSIFICATION No. 9 - Continued

TRANSPORTATION SERVICE - Continued

Definitions - Continued

(11) **Human Needs Customer** is one who receives service under a firm service classification:

(a) for the Customer's own or another's residential uses and purposes whether involving temporary or permanent occupancy, which includes residential hotels, single room occupancies, prisons, and living facilities of clergy, or

(b) in buildings having no alternate energy facilities that are acute care or nursing home providers housing patients or residents on an overnight basis including, nursing homes, hospitals, community residences, and shelters

as the same may be known to Con Edison as of May 9, 1997 or as the applicant may state on the application for service thereafter.

(11a) **Interruptible Delivery Requirement** is the quantity of gas the Seller is required to deliver to the Company's Citygate Receipt Point(s) under the Interruptible Monthly Balancing Service. The Company shall determine this amount each month which the Seller is obligated to deliver to the Receipt Point(s) in equal daily increments during the month, unless.modified during the month in accordance with Operational Matters (C) (2) in Service Classification No. 20.

(12) **Maximum Daily Transportation Quantity** is the highest Daily Transportation Quantity that the Company is obligated to accept at the Receipt Point(s) on any day.

(13) **Operational Flow Order ("OFO")** means a directive by the Company to a Direct Customer(s) and/or its gas supplier(s) and/or a Marketer serving customers in its aggregation group to adjust Citygate deliveries of gas to alleviate conditions that threaten the integrity of the system.

(14) **Receipt Point** means the Citygate point(s) set forth in the Customer's service agreement or a Local RNG Production facility.

(15) **Seller** means a non-utility entity who subscribes to SC 20 service and is determined eligible by the Department of Public Service to provide or arrange to provide natural gas supply and other services to a Customer or Group. The term "Seller" means "Marketer" and is used interchangeably elsewhere in this tariff and the Operating Procedures.

(Service Classification No. 9 - Continued on Leaf No. 261.1)

SERVICE CLASSIFICATION No. 9 - Continued
TRANSPORTATION SERVICE - Continued

Character of Service - Continued

(B) Interruptible Transportation:

Transportation to a Customer, who is also served under Service Classification No. 12 Rate I, will be interrupted by means of notification by the Company . A Customer shall curtail the use of gas, at any time the Company deems necessary, upon notice given to the Customer in accordance with the Company's Gas Sales and Transportation Operating Procedures.

(C) Off-Peak Firm Transportation:

Transportation to a Customer with estimated annual usage of 1,000,000 therms or greater and who is also served under Service Classification No. 12 Rate II. Off-Peak Firm service shall be provided for a minimum of 335 days during each annual period commencing November 1. The Company may, in its sole discretion, curtail or interrupt service for up to 30 consecutive or nonconsecutive days during each Winter Period. If service commences on other than November 1 during a Winter Period, the Customer shall be subject to interruption with all other Off-Peak Firm Customers during that Winter Period and all subsequent Winter Periods, whether or not the total number of days of interruption during that initial Winter Period and the partial Winter Period at the end of the Customer's term of service exceeds 30 days. An interruption for all or part(s) of a day shall be considered as one day of interruption.

(Service Classification No. 9 - Continued on Leaf No. 265)

SERVICE CLASSIFICATION No. 9 – Continued

TRANSPORTATION SERVICE – Continued

Rates

Any of the following rates or charges, described but not shown shall be set forth on a statement filed with the Commission. The exceptions are the "Value Added Charge" component of the Power Generation Transportation Rate, which will be posted on the Company's Secured Internet web site, and the Firm Transportation Base Rates, which are shown under the Rates Sections of the otherwise applicable Firm Full Service Classifications and Riders.

The Base Rates set forth below (A) - (D) apply to the monthly sum of the Customer's Daily Delivery Quantities:

(A) Firm Transportation Base Rates for Customers Otherwise Eligible for Service Classification Nos. 1, 2, 3 or 13

The Base Rates for Firm Transportation customers are equal to the Base Rates for the otherwise applicable Firm Full Service Classifications and Riders. The Firm Transportation rate classes and their equivalent Firm Full Service rate classes are as follows:

Firm Transportation Rate Class	Equivalent Firm Full Service Rate Class
SC9 (A)(1)	Eligible for Service Classification No. 1
SC9 (A)(2)	Eligible for Service Classification No. 2 Rate I
SC9 (A)(3)	Reserved For Future Use
SC9 (A)(3a)	Eligible for Service Classification No. 2 Rate I Rider D
SC9 (A)(4)	Eligible for Service Classification No. 2 Rate II
SC9 (A)(5)	Reserved For Future Use
SC9 (A)(5a)	Eligible for Service Classification No. 2 Rate II Rider D
SC9 (A)(6)	Eligible for Service Classification No. 3
SC9 (A)(7)	Applicable to that portion of the Customer's gas usage billed at the air conditioning rates set forth in Service Classification Nos. 2 and 3
SC9 (A)(8)	Eligible for Service Classification No. 13
SC9 (A)(9)	Eligible for Service Classification No. 2 Rider H
SC9 (A)(10)	Eligible for Service Classification Nos. 1 and 3, Rider J

(Service Classification No. 9 - Continued on Leaf No. 270)

SERVICE CLASSIFICATION No. 9 - Continued

TRANSPORTATION SERVICE - Continued

Rates - Continued

(B) Interruptible Transportation Rates for Customers also Served under Service Classification No. 12 Rate 1:

The Posted Rates Section of Service Classification No. 12 defines the eligibility criteria, the monthly minimum charge, and the blocked rate structure for interruptible service and the Character of Service section defines the method of service interruption.

Posted Rates:

Separate base rates are established for Residential Transportation Service for Customers served under Service Classification ("SC") No. 9, whose equivalent firm sales SC would be SC 1 or SC 3 and Non-Residential Transportation Service for Customers served under SC 9 whose equivalent firm sales SC would be SC 2. Both Residential and Non-Residential Customers will be served under the same block rate structure with a monthly minimum charge of $100.00 for the first 3 therms or less. The volumetric base rates are set at 70% of each of the SC 3 volumetric block rates for Residential Customers and 70% of each of the SC 2 Rate II volumetric block rates for Non-Residential Customers. These rates, which represent local distribution charges, are shown under the Rates Section of Service Classification No. 12 and shall be posted monthly on the Statement of Rate for Service Classification No. 9.

(Service Classification No. 9 - Continued on Leaf No. 275)

SERVICE CLASSIFICATION No. 9 - Continued

TRANSPORTATION SERVICE - Continued

Rates - Continued

(B) Interruptible Transportation Rates for Customers also Served under SC 12 Rate 1 - Continued

Negotiated Rates:

The Company may, at its sole discretion, individually negotiate a separate rate with a Customer who can demonstrate, to the Company's satisfaction, that it has energy alternatives at a cost below the applicable posted Service Classification No. 12, Rate I sales rate, or rate requirements that differ from the posted rates.

(C) Off-Peak Firm Transportation Rates for Customers also Served Under Service Classification No. 12 Rate 2:

For Customers being served under contracts entered into on or after January 1, 2019, the rate per therm for one, two, or three year contracts shall be 8.75 cents per therm until these contracts expire. The applicable rate shall be reduced by 1.0 cent per therm for monthly usage in excess of 500,000 therms.

The Customer and the Company may agree upon a rate equal to or greater than the prevailing contract rate per therm for a term greater than three years, which, subject to the agreement of the parties, may or may not be subject to a 1.0 cent per therm reduction for usage in excess of 500,000 therms.

(Service Classification No. 9 - Continued on Leaf No. 276)

SERVICE CLASSIFICATION No. 9 - Continued

TRANSPORTATION SERVICE - Continued

Rates - Continued

(G) Balancing Service Charges for Firm Transportation Customers

(1) The cost of the Baseload Service and Tiers 2 and 3 of the Daily Delivery Service will be billed directly to the firm transportation customers' Marketers. Firm sales customers will pay for their share of these costs through the GCF. The terms of the Daily Delivery Service are described in the Operational Matters Sections (C) of Service Classification No. 20 and further explained in the Company's GTOP Manual.

(Service Classification No. 9 - Continued on Leaf No. 280)

SERVICE CLASSIFICATION No. 9 – Continued

TRANSPORTATION SERVICE - Continued

Rates - Continued

(I) Balancing Services and Charges for CNG, Bypass and Power Generation Customers - Continued

(2) Balancing Services and Charges for Power Generation Transportation Customers - Continued

The cost of gas used in calculating the Daily Cashout Credit shall be a weighted average price equal to the product of the percentage weightings, as defined in the GTOP, and the Transco Zone 6-New York, Tetco M3 and Iroquois Z2 Midpoint price as published in Platt's Gas Daily on the day in which the imbalance occurs.

The Customer will also be responsible for any pipeline penalties that may result from net deficiencies or surpluses.

(J) Other Rates, Charges and Adjustments:

Customers shall be responsible for paying one or more of the following rates, charges or adjustments, as applicable, in addition to the Base Rates and, where applicable, Minimum Charge, Low Income Discount under Rider E, and Balancing Service Charges:

(1) Monthly Rate Adjustment:
All Firm Base Rates shall be adjusted for the components of the Monthly Rate Adjustment applicable to SC Nos. 1, 2, 3, and 13 as set forth in General Information Section VII (B) and the Capacity Release Service Adjustment in Rate Provision (J)(5). Firm Base Rates applicable to Customers eligible for Service Classification No. 2 - Rate II, Service Classification No. 2 - Rate II - Rider D, Service Classification No. 3, and Service Classification No. 3 Rider J Rate II shall also be adjusted for the Weather Normalization Adjustment as set forth in General Information Section IX. 1.

(2) Gas Importer Tax:
In accordance with Section 189 of the New York Tax Law (Chapter 166, Section 147, and Chapter 410 of the Laws of 1991), a tax shall be due and owing for natural gas (termed "gas services" in Section 189) purchased outside New York State from a supplier other than the Company and delivered by the Company to a Customer served under this Service Classification. Such taxes are required to be paid by the Customer to the Company. The tax shall be calculated at the applicable rate in effect, plus applicable surcharges thereon imposed under Sections 186-b, 186-c and 188 of the New York Tax Law, on the cost of gas services, which is presumed to be the "annual average gas price" per Mcf published by the United States Department of Energy on July 1 each year as defined in Section 189. The Company shall calculate the tax required to be collected by multiplying the number of cubic feet of gas service delivered to the Customer during the billing period times the cost of gas services times the tax rate including surcharges thereon.

(3) Increase in Rates and Charges:
The rates and charges under this Service Classification shall be increased by the applicable percentage, in accordance with General Information Section VIII.

(Service Classification No. 9 - Continued on Leaf No. 301)

SERVICE CLASSIFICATION No. 9 - Continued
TRANSPORTATION SERVICE - Continued

Rates - Continued

(J) Other Rates, Charges and Adjustments – Continued

(11) Charges for Non-Compliance (“Non-Compliance Charge”)

For a Power Generation Customer: The Charge for Non-Compliance is the difference between

(a) 130% of the higher of a published distillate fuel index price, as determined in accordance with the Sales and Transportation Operating Procedures, or the Power Generation Gas Price, and

(b) the Power Generation Gas Price.

The Power Generation Gas Price is defined as the sum of the Power Generation rate excluding the Value Added Charge (VAC) and the cost of gas used in generating electricity as recognized in determining the VAC.

(12) Reserved for Future Use

(13) Daily Penalty Charge

Commencing December 1, 2019, Interruptible and Off-Peak Firm Customers, including Contract Interruptible and Off-Peak Firm Industrial Customers, but excluding Power Generation Customers, will be charged a daily penalty for failing to return a signed affidavit by the close of business on October 1, or by the close of business on the following business day if October 1 falls on a weekend or holiday, as specified under Miscellaneous Provision (D) of this Service Classification. Beginning December 1, 2019, and every November 1 thereafter, the customer will be subject to the daily penalty for every day of the current winter season that the signed affidavit has not been received by the Company or March 31 (i.e., the end of the heating season), whichever is earlier.

The Daily Penalty Charge is set at $100 per day for an Interruptible Rate 1 Customer and $1,000 per day for an Off-Peak Firm Customer.

Daily Penalty Charges shall not be recognized in the calculation of the minimum charge or annual reconciliation. Once an Interruptible or Off-Peak Firm Customer switches to firm service or terminates its gas service all daily penalty charges will cease.

Daily Penalty Charges shall be increased by the applicable percentage for the Increase in Rates and Charges, in accordance with General Information Section VIII.

(Service Classification No. 9 - Continued on Leaf No. 304)

SERVICE CLASSIFICATION NO. 9 - Continued

TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions – Continued

(C) Terms of Payment and Billing - Continued

For a Customer receiving bills from a Billing Agent, a late payment charge may be applied to all amounts billed, including arrears, and unpaid late payment charges which are not received by the Customer's Billing Agent within at least 25 days of the date the Billing Agent received the Customer's billing information from the Company.

(D) Interruptions of Service and Reserve Requirements for Interruptible, Off-Peak Firm, and Power Generation Customers

The Company reserves the right to reject any application for service, or to interrupt service, under this Service Classification where, in the sole judgment of the Company, the provision of service would or might impair the Company's rights or ability to receive service, purchase gas, or utilize capacity on the transmission system of any of its pipeline or Local RNG Production suppliers, impair or interfere with the Company's operations, or impose costs in excess of those subject to recovery under these rates.

Service under this Service Classification is also subject to interruption as provided herein and in accordance with General Rule III (14) and the Company's Sales and Transportation Operating Procedures. Service may also be interrupted for all or a portion of a day if necessary for the Company to perform work on its facilities, including testing that an Interruptible, Off-Peak Firm or Power Generation Customer's alternate fuel or alternate energy facilities and associated phone lines and communication equipment are operable.

The Customer shall immediately (1) notify the Company of any condition that would prevent the required interruption of service, including preventing the Interruptible, Off-Peak Firm, or Power Generation Customer from using its alternate fuel or alternate energy facilities or preventing the Company from determining whether the Customer is using gas during an interruption; (2) take immediate action to correct such conditions; and (3) notify the Company when such conditions have been corrected. Except as otherwise set forth in this Service Classification or the Company's Sales and Transportation Operating Procedures, such notification shall not exempt the Customer from any applicable Charges for Unauthorized Use, Charges for Non-Compliance, Daily Penalty Charges and other applicable charges and surcharges. Interruptible, Off-peak Firm and Power Generation Customers must conform to the following additional requirements.

By October 1 of each year, Customers are required to demonstrate to the Company that by November 1 of that year they will have adequate reserves of their alternate fuel or energy source based on each Customer's peak Winter Period requirements.

All Customers, excluding Power Generation Customers, taking service under this Service Classification must submit to the Company by the close of business on October 1, or by the close of business on the following business day if October 1 falls on a weekend or holiday, a signed affidavit, as referenced in the Company's Sales and Transportation Operating Procedures.

(Service Classification No. 9 - Continued on Leaf No. 316.1)

SERVICE CLASSIFICATION NO. 9 - Continued
TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions - Continued

(D) **Interruptions of Service and Reserve Requirements for Interruptible, Off-Peak Firm, and Power Generation Customers-Continued**

Process load customers may elect to comply with Company-initiated interruptions of service by shutting down their operations in lieu of maintaining an alternate fuel supply/energy source and meeting the alternate fuel reserve requirement (“Shut-Down Option”). For purposes of this provision, process load Customers are Customers that: a) use gas predominantly for manufacturing or other industrial purposes; b) can withstand a suspension of such manufacturing or industrial operations for the duration of an interruption; and c) can shut down such operations in the time frame required under this Service Classification upon notice by the Company of a period of interruption. Customers ineligible for the Shut-Down Option include, but are not limited to: Human Needs Customers, Critical Care Customers, schools, non-residential Customers using gas primarily for space heating purposes, and electric generators. A Customer electing this option must submit to the Company, by October 1 of each year, a signed affidavit form which may be found in the Company’s Gas Sales and Transportation Operating Procedures, attesting to the Customer's commitment to shut down operations during periods of interruption. If a Customer taking service under this option fails to interrupt its use of gas and shut down its operation during a period of interruption, the Company may, at its sole discretion, physically shut down the Customer's gas service. In addition to any other applicable charges under this Service Classification associated with such failure to interrupt, the Customer must reimburse the Company for any costs incurred to perform the physical shutdown.

A Customer who does not elect the Shut-Down Option may meet the reserve requirement through a combination of on-site storage capacity and by providing satisfactory proof to the Company that a relationship exists with the alternate fuel or energy provider to supply the Customer with the additional amount required to meet the Customer's reserve requirement. Interruptible and Off-Peak Firm Customers whose alternate fuel is distillate fuel or who use gas for Human Needs purposes must have a ten-day reserve. A Power Generation Customer or Contract Interruptible or Off-Peak Firm Industrial Customer whose alternate fuel is distillate fuel must have a five-day reserve. Other Interruptible, Off-Peak Firm and Power Generation Customers must maintain reserve levels acceptable to the Company. A new Interruptible or Off-Peak Firm Customer with alternate fuel (as opposed to alternate energy) capability, commencing service under this Service Classification on and after November 1, 2001, must have, as part of its applicable reserve requirement, three days or more of on-site inventory of its alternate fuel, based upon the Customer's peak Winter Period requirements, as more specifically provided in the Company's Gas Sales and Transportation Operating Procedures Manual. Customers that fail to conform to the above stated reserve requirements, or who have inoperable dual-fuel equipment, will be subject to the Unauthorized Use Charge, or the Non-Compliance Charge, as applicable:

(Service Classification No. 9 - Continued on Leaf No. 316.2)

SERVICE CLASSIFICATION NO. 9 - Continued
TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions – Continued

(D) Interruptions of Service and Reserve Requirements for Interruptible, Off-Peak Firm and Power Generation Customers - Continued

The Customer shall permit Company representatives access to the Customer's premises at any time without prior notice to inspect the Customer's facilities and equipment to:

(1) determine whether the Customer is using gas during a service interruption, or

(2) verify the accuracy of the meter or the condition of the remote monitoring equipment or alternate fuel or alternate energy equipment.

This inspection shall not satisfy the Customer's obligation to notify the Company of any condition that would prevent the required interruption of gas service and shall not exempt the Customer from any applicable Charges for Unauthorized Use or other charges or surcharges.

(E) Customer Responsibility

Interruptible and Off-Peak Firm Customers with dual-fuel equipment must maintain (i) operable dual-fuel facilities and associated communication equipment and (ii) fuel reserves for use in such dual-fuel facilities in accordance with Miscellaneous Provision D of this Service Classification, including replenishing such fuel inventory during and after an interruption, to the extent necessary, that together are adequate to enable the Customer to operate satisfactorily those facilities without gas whenever and so long as service under this Service Classification is interrupted.

Interruptible and Off-Peak Firm Customers with equipment that operates solely on gas must maintain (i) alternate energy facilities and associated communication equipment, and (ii) alternate energy reserves for such facilities in accordance with Miscellaneous Provision D of this Service Classification, including acquiring additional energy reserves during and after an interruption to the extent necessary, that together are adequate to supply the energy requirements of the premises otherwise supplied directly or indirectly by the gas-fired equipment whenever and so long as service under this Service Classification is interrupted.

Effective January 1, 2017, the Company implemented the daily communications protocol and customer affidavit requirements established in the Commission's December 16, 2016 Order in Case 15-G-0185 as it relates to this Service Classification and as further described in the Company's Sales and Transportation Operating Procedures ("GTOP").

All customers taking service under this Service Classification must submit to the Company, by October 1 of each year, a signed affidavit, in the form included in the Company's Sales and Transportation Operating Procedures. A Customer that fails to submit a signed affidavit by the close of business day on October 1, or by the close of business of the following business day if October 1 falls on a weekend or holiday, will be subject to the Daily Penalty Charge, as described under (J)(13) in the Rates Section of this Service Classification.

(Service Classification No. 9 - Continued on Leaf No. 318)

SERVICE CLASSIFICATION NO. 9 - Continued

TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions - Continued

(E) Customer Responsibility for Equipment - Continued

Power Generation Customers must maintain operable Emergency Low Gas Inlet Pressure Trip Switch, Gas Telemetry Equipment, and any other equipment the Company deems necessary to provide service. Interruptible and Off-Peak Firm Customers who have elected the Shut-Down Option will not be subject to the requirements of this section except that they will be required to maintain communication equipment.

The Company assumes no responsibility for the adequacy of any dual-fuel or alternate energy facilities and shall not be liable for any loss, damage, or expense, direct or indirect, which may be incurred by the Customer or others in connection with or as a result of any curtailment, interruption, or discontinuation of gas service, unless there is a separate agreement between the Customer and the Company that establishes such responsibility.

(F) Prepayment for Facilities

(1) Applicable to Requests for Interruptible or Off-Peak Firm Service

An applicant for new service or a Service Classification Nos. 1, 2, 3, or 13 Customer transferring to this service and requiring additional facilities shall pay in advance the costs to be incurred by the Company covering:

(a) provision and installation of metering and communication equipment as specified by the Company, and

(b) all main extensions or reinforcements, service pipes, service connections, and other facilities in any street, avenue, road, or way as may be or were necessary to render service; except:
   (i) Minimum Charge revenues for the contract term of an Off-Peak Firm Customer applying for service on or after March 1, 2014 will be used to offset all or a portion of the Customer's cost responsibility; or
   (ii) to the extent the Customer qualifies for one of the Company's incentive programs in effect at the time of the Customer's application for service under this Service Classification.

A Service Classification Nos. 1, 2, 3, or 13 Customer transferring to this service after taking firm sales service for less than five years, may in the Company's sole discretion, be required to pay all or a portion of the facility costs previously incurred for the Customer. For Off-Peak Firm Customers applying for service on or after March 1, 2014, Minimum Charge revenues for the Customer's contract term may be used to offset all or a portion of such cost responsibility.

(Service Classification No. 9 - Continued on Leaf No. 319)

SERVICE CLASSIFICATION NO. 9 - Continued

TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions - Continued

(M) Applicable Riders

(1) Rider A - ("Continuance of Agreement for Service by Receiver, Trustee, or Like Officer of Court").

(2) Rider B - ("Conjunctional Billing") for any SC 2, 3 or 9 Customer, religious corporation or association under SC 1, or veterans' organization under SC 1 converting to Firm Service under this Service Classification who receives Service Classification Nos. 1, 2, or 3 service under Rider B.

(3) Rider C - ("Intercommunicating Buildings") for any Service Classification No. 2 or 3 Customer and religious corporation or association under Service Classification No. 1, or veterans' organization under SC 1 converting to Firm Service under this Service Classification who receives Service Classification Nos. 1, 2, or 3 service under Rider C.

(4) Rider D - "Excelsior Jobs Program" – Service Classification Nos. 2 and 9 (for an explanation of Rider D, see Leaf No. 125).

(5) Rider E - "Low Income Program" - Service Classification Nos. 1, 3 and 9 (see General Information Section VI).

(6) Rider F - RESERVED FOR FUTURE USE

(7) Rider G - RESERVED FOR FUTURE USE

(8) Rider H - "Distributed Generation Rate" (for an explanation of Rider H, see Leaf No. 154.1).

(9) Rider I - RESERVED FOR FUTURE USE

(10) Rider J - "Residential Distributed Generation Rate" (for explanation of Rider J, see Leaf No. 154.20).

(N) Application Forms

An applicant for service may be required to complete either the residential or nonresidential form for service, included in General Information Section XI 1 and 2, and any other form(s) required by and included in the Company's Sales and Transportation Operating Procedures.

(Service Classification No. 9 - Continued on Leaf No. 326.1)

SERVICE CLASSIFICATION NO. 9 - Continued

TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions - Continued

(O) On-site Meter Reading Fee

An on-site meter reading is an actual reading at an SC 9 Customer's premises on the regularly scheduled meter reading date in the event that the Customer's communication equipment used for remote communications is not operational. Where an on-site meter reading is required, the charge will be $19.00. The fee will not be assessed on SC 9 customers whose communication equipment is maintained by the Company or SC 9 Customers with AMI metering equipment.

(P) Special Meter Reading Fee

Where a Customer or Marketer requests a special meter reading for an SC 9 Customer, the charge will be $19.00 per Customer account per visit.

A special meter reading is a meter reading at the Customer's premises performed on a date that is different from the customer's regularly scheduled meter reading date. Special meter readings must be scheduled two business days before the special meter reading date.

The Company will complete a meter reading requested by a Residential Customer upon discontinuance of utility service in accordance with the provisions of Public Service Law §39.4, and such customer will be charged the $19.00 fee, subject to the following:

(1) Upon receipt of either oral or written notification from the Residential Customer that the Customer will be discontinuing gas service, the Company shall notify such Customer of their right to an actual meter reading;

(2) The Company shall attempt to read the meter within 48 hours of such request for termination on discontinuation of gas service to a Residential Rustomer, provided that if circumstances beyond the control of the Company make an actual reading of the meter extremely difficult, the Company shall not be required to provide an actual meter reading;

(3) The Company shall not be required to provide a meter reading during a holiday or non-work day, but shall instead provide such meter reading on the next workday;

(4) The Company shall only charge a customer one special meter reading fee for reading both meters should the Customer request final meter readings for both electric and gas service; and

(5) The Company will not charge a meter reading fee to a Residential Customer where the Company has the ability to read the customer's meter without sending personnel to the Customer's premises.

(Service Classification No. 9 - Continued on Leaf No. 327)

SERVICE CLASSIFICATION NO. 12

DUAL-FUEL SALES SERVICE (DFSS)

Table of Contents

(Service Classification No. 12 - Continued on Leaf No. 328)

SERVICE CLASSIFICATION NO. 12 - Continued
DUAL-FUEL SALES SERVICE (DFSS) - Continued

Availability of Service

Service shall be provided in accordance with the terms of this Service Classification for any use of gas by a Customer who:

(1) maintains operable dual-fuel facilities capable of supplying the entire requirements of the equipment (except for air-conditioning equipment) with gas or an alternate fuel, or can utilize electricity or another energy source to supply the energy requirements of the premises otherwise supplied directly or indirectly by gas,

(2) agrees to switch its equipment from gas to an alternate fuel or alternate energy source and maintains appropriate control devices, in accordance with the Company's Gas Sales and Transportation Operating Procedures, and

(3) meets the requirements of this Service Classification, the Company's Gas Sales and Transportation Operating Procedures, and other applicable provisions of this Rate Schedule.

Requirements (1) and (2) above do not apply to Customers taking service under the Shut-Down Option. Requirements (1) and (2) above, as well as the requirement to submit to the Company a signed affidavit by October 1 of each year, do not apply to Residential Customers, with a maximum of four dwelling units, who request gas service for the purpose of supplying an emergency electric generator as specified under General Information Section III.3.(H).

Applications under this Service Classification shall not be accepted where the Company determines, in its sole discretion that the requirements of existing Customers and Company gas use may not leave sufficient gas available for use by others.

Character of Service

(A) Interruptible (Rate 1):

Sales of gas at the Customer's meter shall be interruptible by means of notification by the Company. A Customer shall curtail the use of gas, at any time the Company deems necessary, upon notice given to the Customer in accordance with the Company's Gas Sales and Transportation Operating Procedures.

(Service Classification No. 12 - Continued on Leaf No. 330)

SERVICE CLASSIFICATION NO. 12 - Continued

DUAL-FUEL SALES SERVICE (DFSS) - Continued

Character of Service - Continued

(B) Off-Peak Firm (Rate 2):

Off-peak firm sales of gas for a minimum of 335 days during each annual period commencing November 1 for any Customer whose estimated annual use of gas is 1,000,000 therms or greater, determined in accordance with the Company's Gas Sales and Transportation Operating Procedures.

The Company may, in its sole discretion, curtail or interrupt service for up to 30 consecutive or nonconsecutive days during each Winter Period, which is defined as beginning on November 1 and ending the following March 31. If service commences on other than November 1 during a Winter Period, the Customer shall be subject to interruption with all Rate 2 Customers during that Winter Period and all subsequent Winter Periods, whether or not the total number of days of interruption during that initial Winter Period and the partial Winter Period at the end of the Customer's term of service exceeds 30 days. An interruption for all or part(s) of a day shall be considered as one day of interruption.

(Service Classification No. 12 - Continued on Leaf No. 331)

SERVICE CLASSIFICATION NO. 12 - Continued

DUAL-FUEL SALES SERVICE (DFSS) - Continued

Character of Service - Continued

(C) Monthly Elections:

A Service Classification No. 12 Customer who is also a Service Classification No. 9 Interruptible or Off-Peak Firm transportation customer shall notify the Company in advance of each month, in accordance with the Company's Sales and Transportation Operating Procedures, whether it elects for the entire following calendar month to receive:

(1) Service Classification No. 12 Sales Service; or

(2) Service Classification No. 9 Transportation Service.

A Customer who fails to make a timely election shall be deemed to have elected sales service, unless the Customer previously advised the Company in writing that transportation service should be its default service.

Rates

Any of the following rates or charges described but not shown shall be set forth on a statement filed with the Commission.

(A) Interruptible Base Rate (Rate 1):

(1) Posted Rates:

Customers will be subject to:

	Residential	Non – Residential
Monthly Minimum Charge for delivery of 3 therms or less:	$100.00	$100.00
For the next 87 therms	109.84 cents per therm	87.55 cents per therm
For the next 2,910 therms	86.99 cents per therm	68.46 cents per therm
For excess over 3,000 therms	70.27 cents per therm	49.96 cents per therm

(Service Classification No. 12 - Continued on Leaf No. 332)

SERVICE CLASSIFICATION NO. 12 - Continued

DUAL-FUEL SALES SERVICE (DFSS) - Continued

Rates - Continued

(A) Interruptible Base Rate (Rate 1) - Continued

(1) Posted Rates – Continued

The base delivery rates shall be posted on a monthly basis, on the Statement of Rate for Service Classification No. 12. The base commodity rate shall also be posted on a monthy basis, on the Statement of Rate for Service Classification No. 12 and shall include components reflecting the commodity cost of gas (inclusive of volumetric pipeline charges and surcharges), and a contribution to the Company's pipeline fixed charges. The Company may increase or decrease the supply related rate level(s), at its sole discretion, at any time during the month upon notice to the Customer given in accordance with the Company's Sales and Transportation Operating Procedures.

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(Service Classification No. 12 - Continued on Leaf No. 333)

SERVICE CLASSIFICATION NO. 12 - Continued

DUAL-FUEL SALES SERVICE (DFSS) - Continued

Rates - Continued

(A) Interruptible Base Rate (Rate 1) - Continued

(2) Negotiated Rates:

The Company may, at its sole discretion, individually negotiate a separate rate with a Customer who can demonstrate, to the Company's satisfaction, that it has energy alternatives at a cost below or rate requirements that differ from the applicable posted rates.

(B) Off-Peak Firm Rate (Rate 2):

The Company shall establish a commodity rate effective on the first calendar day of each month. The commodity rate will be determined at the sole discretion of the Company. On the fourth business day prior to the first day of the following month, the Customer shall be notified by the Company of the new monthly Citygate sales rate through the use of the Internet, by fax document, by telephone or other electronic medium. By 5:00 PM of the next business day, the Customer must elect sales service or transportation service for the entire following calendar month. The Company, at its discretion, may post subsequent prices that differ from the initial price, the last of which shall be posted no later than 4:00 PM of the third business day before the end of the month. Customers may lock into any price offered by the Company until 11:00 AM of the second business day as described in the Company's Sales and Transportation Operating Procedures. Once the Customer locks into a price, that price will be unaffected by any price posted thereafter.

The Company may reduce the rate at any time during the month upon notice to the Customer given in accordance with the Company's Sales and Transportation Operating Procedures. In such event, Customers that elected transportation service for that month shall have the option, subject to the availability of gas supply, to elect sales service for the balance of that month.

The commodity rate shall consist of components reflecting the commodity cost of gas (inclusive of volumetric pipeline charges and surcharges), and a contribution to the Company's pipeline fixed charges.

(Service Classification No. 12 - Continued on Leaf No. 334)

SERVICE CLASSIFICATION NO. 12 - Continued

DUAL-FUEL SALES SERVICE (DFSS) - Continued

Rates - Continued

(B) Off-Peak Firm Rate (Rate 2) - Continued

The delivery rates for Customers being served under contracts entered into on or after January 1, 2019, for one, two, or three year contracts shall be 8.75 cents per therm until these contracts expire. The applicable rate shall be reduced by 1.0 cent per therm for monthly usage in excess of 500,000 therms.

The Customer and the Company may agree upon a rate equal to or greater than the prevailing contract rate per therm for a term greater than three years, which, subject to the agreement of the parties, may or may not be subject to a 1.0 cent per therm reduction for usage in excess of 500,000 therms.

The pipeline fixed charge component and the local distribution charge may be discounted, at the sole discretion of the Company. During the months of April through October, pipeline fixed charges shall be discounted before the local distribution charge. During the months of November through March, the local distribution charge shall be discounted before the pipeline fixed charges.

The Company, subject to the terms set forth in the Company's Operating Procedures, will consider a request from a Customer that has an estimated annual gas usage of 3,000,000 therms or greater to negotiate a local distribution rate other than the local distribution rates set forth above. Any such negotiated rate will be fixed for a term of no less than three consecutive calendar months, provided however that the Customer will continue to be subject to the full minimum charge as set forth in Rate Provision (C) of this Service Classification.

Service Classification No. 12 - Continued on Leaf No. 335)

SERVICE CLASSIFICATION NO. 12 - Continued
TRANSPORTATION SERVICE - Continued

Miscellaneous Provisions - Continued

(D) Interruptions of Service and Reserve Requirements for Interruptible and Off-Peak Firm Customers-Continued

Interruptible and Off-Peak Firm Customers must conform to the following additional requirements. All Customers taking service under this Service Classification must submit to the Company by the close of business on October 1, or by close of business on the following business day if October 1 falls on a weekend or holiday, a signed affidavit, as referenced in the Company's Sales and Transportation Operating Procedures. By October 1 of each year, Customers are required to demonstrate to the Company that by November 1 of that year they will have adequate reserves of their alternate fuel or energy source based on each Customer's peak Winter Period requirements.

Process load Customers may elect to comply with Company-initiated interruptions of service by shutting down their operations in lieu of maintaining an alternate fuel supply/energy source and meeting the alternate fuel reserve requirement ("Shut-Down Option"). For purposes of this provision, process load Customers are Customers that: a) use gas predominantly for manufacturing or other industrial purposes; b) can withstand a suspension of such manufacturing or industrial operations for the duration of an interruption; and c) can shut down such operations in the time frame required under this Service Classification upon notice by the Company of a period of interruption. Customers ineligible for the Shut-Down Option include, but are not limited to: Human Needs Customers Critical Care Customers, schools, non-residential Customers using gas primarily for space heating purposes, and electric generators. A Customer electing this option must submit to the Company, by October 1 of each year, a signed affidavit form which may be found in the Company's Gas Sales and Transportation Operating Procedures, attesting to the Customer's commitment to shut down operations during periods of interruption. If a Customer taking service under this option fails to interrupt its use of gas and shut down its operation during a period of interruption, the Company may, at its sole discretion, physically shut down the Customer's gas service. In addition to any other applicable charges under this Service Classification associated with such failure to interrupt, the Customer must reimburse the Company for any costs incurred to perform the physical shutdown.

A Customer who does not elect the Shut-Down Option may meet the reserve requirement through a combination of on-site storage capacity and by providing satisfactory proof to the Company that a relationship exists with the alternate fuel or energy provider to supply the Customer with the additional amount required to meet the Customer's reserve requirement. Interruptible or Off-Peak Firm Customers whose alternate fuel is distillate fuel or use gas for Human Needs purposes must have a ten-day reserve. A Power Generation Customer or Contract Interruptible or Off-Peak Firm Industrial Customer, as defined in the Definition section of Service Classification No. 9, whose alternate fuel is distillate fuel must have a five-day reserve. Other Interruptible or Off-Peak Firm Customers must maintain reserve levels acceptable to the Company. A new Interruptible or Off-Peak Firm Customer with alternate fuel (as opposed to alternate energy) capability, commencing service under this Service Classification on and after November 1, 2001, must have, as part of its applicable reserve requirement, three days or more of on-site inventory, based upon the Customer's peak winter period requirements, as more specifically provided in the Company's Gas Sales and Transportation Operating Procedures Manual. Customers that fail to conform to the above stated reserve requirements, or who have inoperable dual-fuel equipment, will be subject to the Unauthorized Use Charge, or the Non-Compliance Charge, as applicable:

(Service Classification No. 12- Continued on Leaf No. 341.2)

SERVICE CLASSIFICATION NO. 12 - Continued
DUAL-FUEL SALES SERVICE (DFSS) - Continued

Miscellaneous Provisions - Continued

(E) Customer Responsibility:

Interruptible and Off-Peak Firm Customers with dual-fuel equipment must maintain (i) operable dual-fuel facilities and associated communication equipment and (ii) fuel reserves for use in such dual-fuel facilities in accordance with Miscellaneous Provision D of this Service Classification, including replenishing such fuel inventory during and after an interruption, to the extent necessary, that together are adequate to enable the Customer to operate satisfactorily those facilities without gas whenever and so long as service under this Service Classification is interrupted. A Customer with AMI metering will not be required to install and maintain associated communication equipment.

Interruptible and Off-Peak Firm Customers with equipment that operates solely on gas must maintain (i) alternate energy facilities and associated communication equipment, and (ii) alternate energy reserves for such facilities in accordance with Miscellaneous Provision D of this Service Classification, including acquiring additional energy reserves during and after an interruption to the extent necessary, that together are adequate to supply the energy requirements of the premises otherwise supplied directly or indirectly by the gas-fired equipment whenever and so long as service under this Service Classification is interrupted. A Customer with AMI metering will not be required to install and maintain associated communication equipment

Effective January 1, 2017, the Company implemented the daily communications protocol and customer affidavit requirements established in the Commission’s December 16, 2016 Order in Case 15-G-0185 as it relates to this Service Classification and as further described in the Company’s Sales and Transportation Operating Procedures (“GTOP”).

All customers taking service under this Service Classification must submit to the Company, by October 1 of each year, a signed affidavit, in the form included in the Company’s Sales and Transportation Operating Procedures. A Customer that fails to submit a signed affidavit by the close of business on October 1, or by the following business day if October 1 falls on a weekend or holiday, will be subject to the Daily Penalty Charge, as described under (D)(6) in the Rates Section of this Service Classification and (J)(13) in the Rates Section of Service Classification No 9.

The Company assumes no responsibility for the adequacy of any dual-fuel or alternate energy facilities and shall not be liable for any loss, damage, or expense, direct or indirect, which may be incurred by the Customer or others in connection with or as a result of any curtailment, interruption, or discontinuation of gas service.

Interruptible and Off-Peak Firm Customers who have elected the Shut-Down Option will not be subject to the requirements of this section except that they will be required to maintain communication equipment. A Customer with AMI metering will not be required to install and maintain associated communication equipment.

(Service Classification No. 12 - Continued on Leaf No. 342.1)

SERVICE CLASSIFICATION NO. 13 - Continued

SEASONAL OFF-PEAK FIRM SALES SERVICE - Continued

Rate

Base Rate (per month)

During the period April 1 through October 31, inclusive:

For the first………….................................	3 therms (or less)	$76.97	
For the next……….......................................	1,197 therms	60.29	cents per therm
For excess over………….	1,200 therms	51.57	cents per therm

Penalty Rate

During the period November 1 through March 31, inclusive, a Customer who uses gas under this Service Classification shall be billed at and pay five times the applicable delivery rate per therm of gas at the base rate set forth above, except that the minimum charge shall not apply. The Merchant Function Charge, Billing and Payment Processing Charge, System Benefits Charge, Gas Cost Factor and Monthly Rate Adjustment as discussed below, will also be included in the amount billed.

Minimum Charge (per month):

The Monthly Minimum Charge shall be the charge for the first 3 therms of gas.

Merchant Function Charge, Billing and Payment Processing Charge, and System Benefits Charge:

A Firm Sales Customer taking service under this rate is also subject to the Merchant Function Charge, Billing and Payment Processing Charge, and System Benefits Charge, as explained in General Information Section IX.

Gas Cost Factor and Monthly Rate Adjustment:
A firm sales Customer taking service under this rate is also subject to the Gas Cost Factor applicable to this Rate Schedule and the Monthly Rate Adjustment as explained in General Information Section VII.

(Service Classification No. 13 - Continued on Leaf No. 350)

SERVICE CLASSIFICATION NO. 20 - Continued
TRANSPORTATION RECEIPT SERVICE (TRS) - Continued

Charges and Credits - Continued

(D) Cashout Credits and Charges - Continued

(2) Daily Balancing Service and Monthly Balancing Service for Interruptible and Off-Peak Firm Customers - Continued

(a) Cashout Credit and Charges for Interruptible Daily Balancing - Continued

The cost of gas used in calculating the cashout charge shall be a weighted average price equal to the product of the percentage weightings, as set forth in the GTOP, and the higher of (i) the monthly average of the daily prices for the Transco Zone 6 - NY, Tetco M3 and Iroquois Z2 Citygate indices (full gas days of interruption excluded) or (ii) the Transco Z6-NY, Tetco M3 and Iroquois Z2 First of the Month High Range Price, as reported in the publication, "Platt's Gas Daily" for the month in which the imbalances occurred.

(b) Cashout Credit and Charges for Interruptible Monthly Balancing

The Seller/Direct Customer shall receive a Monthly Cashout Credit on the amount by which the aggregate Daily Delivery Quantities are less than the aggregate Interruptible Delivery Requirement for the billing period ("Net Surplus Imbalance") and pay a Monthly Cashout Charge on the amount by which the aggregate Daily Delivery Quantities are greater than the aggregate Interruptible Delivery Requirement for the billing period ("Net Deficiency Imbalance").

The Monthly Cashout Credit on the Net Surplus Imbalance will be priced at 100% of the cost of gas. The cost of gas used in calculating the monthly cashout credit shall be a weighted average price equal to the product of the percentage weightings, as set forth in the GTOP, and the lower of (i) the monthly average of the daily prices for the Transco Zone 6 - NY, Tetco M3 and Iroquois Z2 Citygate indices (full gas days of interruption excluded) or (ii) the Transco Z6-NY, Tetco M3 and Iroquois Z2 First of the Month Low Range Price, as reported in the publication, "Platt's Gas Daily" for the month in which the imbalances occurred.

The Monthly Cashout Charge on the Net Deficiency Imbalance will be priced at 100% of the cost of gas. The cost of gas used in calculating the monthly cashout charge be a weighted average price equal to the product of the percentage weightings, as set forth in the GTOP, and the higher of (i) the monthly average of the daily prices for the Transco Zone 6 - NY, Tetco M3 and Iroquois Z2 Citygate indices (full gas days of interruption excluded) or (ii) the Transco Z6-NY, Tetco M3 and Iroquois Z2 First of the Month High Range Price, as reported in the publication, "Platt's Gas Daily" for the month in which the imbalances occurred.

The monthly average price of the daily indices for the Transco Zone 6 – NY, Tetco M3 and Iroquois Z2 Citygate indices calculated in (i) above will exclude the days in which service has been interrupted by the Company for an entire gas day.

(Service Classification No. 20 - Continued on Leaf No. 379)

SERVICE CLASSIFICATION NO. 20 - Continued

TRANSPORTATION RECEIPT SERVICE (TRS) - Continued

Operational Matters - Continued

(C) Balancing Services - Continued

(1) Daily Delivery Service:

Effective November 1, 2016, the Load Following Service for firm transportation customers was discontinued and was replaced by the Daily Delivery Service. Marketers serving firm transportation customers taking service under SC No. 9 must participate in the Company's Daily Delivery Service subject to the terms and conditions of this Service Classification and the Company's GTOP Manual.

Each business day, the Company will calculate the following day's Daily Delivery Service Quantity for each Marketer based upon a forecasted daily temperature and the Marketer's Base and Slope Components, as set forth in the GTOP Manual. The Marketer will be obligated to deliver this quantity of natural gas to the Company's City Gate receipt point(s) and to notify the Company of the scheduled deliveries. The Company will not be obligated to accept any delivery in excess of the Marketer's nominated volumes.

At the Company's sole discretion, the Company may permit the Marketer or Marketer's Agent to reduce or increase deliveries of the Daily Delivery Service Quantity on one or more days during any winter month to prevent gas delivery surpluses or deficiencies.

Daily Delivery Service consists of : 1) Baseload, 2) Tier 1 – Mandatory Capacity Release; 3) Tier 2 – Managed Supply (Storage) and 4) Tier 3 – Peaking.

The Daily Delivery Service will also include Renewable Natural Gas ("RNG") pursuant to the Rate Plan approved in Case 19-G-0066.

The Daily Delivery Service is further described in this section and in the GTOP Manual.

Marketer's Share of Company's Daily Delivery Service Assets

Marketers will receive a share of the Company's assets in the Baseload Service and in Tiers 1, 2 and 3. The total share of the Company's assets available for Daily Delivery Service will be determined annually based on the ratio of the firm transportation customers' annual usage as a percentage of total firm customers' annual usage applied to the forecasted design-day peak capacity. On a monthly basis, the Company may update the Marketer's share of the assets allocated for Baseload Service and Tiers 2 and 3 of the Daily Delivery Service based on the Base Component and Slope Component of all Marketers to reflect any changes to the number of their transportation customers and their estimated consumption. Marketers will not be allowed to reduce their share of the Company's assets by the purchase of Local RNG Production Capacity by the Marketer.

(Service Classification No. 20 - Continued on Leaf No. 385.1)

SERVICE CLASSIFICATION NO. 20 - Continued

TRANSPORTATION RECEIPT SERVICE (TRS) - Continued

Operational Matters – Continued

(D) Failure to Deliver:

If Seller at any time fails to deliver the required quantities during an OFO period, in addition to the charges due for its failure to make deliveries, the Company may require Seller as a condition to the continuation of service to Seller Customer(s), and in addition to payment of the required charges, to reimburse the Company in full for the cost of purchasing and installing equipment necessary to:

(1) monitor daily consumption by the Customer(s), and

(2) be in a position to take the action necessary to preserve system integrity if the marketer should fail again to make full deliveries during an OFO period.

In addition, the Company may terminate service to a Seller for Seller's failure to deliver the required quantities for Transportation Service in accordance with SC Nos. 9 and 20 of this Rate Schedule, the UBP and applicable orders of the Commission.

(E) Measurement of Receipts and Heating Value Adjustment:

Quantities of gas received by the Company at the Receipt Point(s) for the Customer's account shall be measured in accordance with the measurement provisions of the tariff of the interstate natural gas pipeline company which delivers the gas to the Receipt Point(s) or, in the case of quantities received from Local RNG Production, in accordance with the measurement provisions of the GTOP and the interconnection agreement applicable to the Local RNG Production source. Volumes of gas delivered by the Company and registered at the Customer's meter in Ccf will be converted to therms, in accordance with General Information Section III. 8.

(Service Classification No. 20 - Continued on Leaf No. 389.4)

SERVICE CLASSIFICATION NO. 20 – Continued

TRANSPORTATION RECEIPT SERVICE (TRS) - Continued

Miscellaneous Provisions - Continued

(M) On-site Meter Reading Fee:

An on-site meter reading is an actual reading at an SC 9 Customer's premises on the regularly scheduled meter reading date in the event that the customer's communication equipment used for remote communications is not operational. Where an on-site meter reading is required, the charge will be $19.00. The fee will not be assessed on SC 9 customers whose communication equipment is maintained by the Company or SC 9 Customers with AMI metering equipment.

(N) Special Meter Reading Fee:

A special meter reading is a meter reading at the Customer's premises performed on a date that is different from the customer's regularly scheduled meter reading date. Special meter readings must be scheduled two business days before the special meter reading date.

Where a special meter reading is requested by the Customer or the Customer's Marketer, the charge will be $19.00 per Customer account per visit.

The Company will complete a meter reading requested by a Residential Customer upon discontinuance of utility service in accordance with the provisions of Public Service Law §39.4, and such customer will be charged the $19.00 fee, subject to the following:

(1) Upon receipt of either oral or written notification from the Residential Customer that the Customer will be discontinuing gas service, the Company shall notify such customer of their right to an actual meter reading;

(2) The Company shall attempt to read the meter within 48 hours of such request for termination on discontinuation of gas service to a Residential Customer, provided that if circumstances beyond the control of the Company make an actual reading of the meter extremely difficult, the Company shall not be required to provide an actual meter reading;

(3) The Company shall not be required to provide a meter reading during a holiday or non-work day, but shall instead provide such meter reading on the next workday;

(4) The Company shall only charge a Customer one special meter reading fee for reading both meters should the Customer request final meter readings for both electric and gas service; and

(5) The Company will not charge a meter reading fee to a Residential Customer where the Company has the ability to read the customer's meter without sending personnel to the Customer's premises.

(Service Classification No. 20 - Continued on Leaf No. 397.2)

SERVICE CLASSIFICATION NO. 20 - Continued

TRANSPORTATION RECEIPT SERVICE (TRS) - Continued

Miscellaneous Provisions – Continued

(O) Account Separation Fee

The Company will charge an ESCO/Marketer $34.50 to separate a combined gas and electric account into two accounts. If a Customer authorizes an ESCO/Marketer for electric service and another ESCO/Marketer for gas service, the Company will charge each ESCO/ Marketer one-half of the applicable charge.

(P) Consolidated Billing And Payment Processing Services

A Marketer and the Company may agree for one party to perform consolidated billing and payment processing services on behalf of the other. Billing and payment processing services for consolidated utility billing are governed by the terms and provisions of retail access billing and payment processing practices, as specified in the UBP, the Home Energy Fair Practices Act (Public Service Law, Article 2) and by such other terms and conditions not inconsistent with otherwise applicable laws, regulations, and Commission Orders as reflected in a Billing Services Agreement between the Company and the Marketer.

The Company will issue Consolidated Bills only for ESCO/Marketers participating in the POR program. A non-participating ESCO/Marketer may offer consolidated billing and/or dual billing options as set forth in the Company's Gas Sales and Transportation Operating Procedures ("Operating Procedures"). For residential customers of a non-participating Marketer, the Marketer may only offer dual billing. According to the terms and conditions of the POR program, the Marketer assigns to the Company its rights in amounts billed to all of its Customers participating in the Company's Retail Access Program and receiving a Consolidated Bill. In turn, the Company will purchase the gas supply service accounts receivable at a discount ("POR Discount Percentage") from the participating Marketer without recourse on the accounts of the Company's firm transportation Customers who receive a consolidated bill that includes gas supply service provided by the ESCO/Marketer.

Under the POR program, the Company shall remit to the ESCO/Marketer undisputed ESCO/Marketer charges billed to its customers, reduced by the POR Discount Percentage. The POR Discount Percentage shall consist of an Uncollectible Bill Percentage, a Risk Factor, a Credit and Collections component, and an Incremental Cost component associated with POR program administration. The four components will be set annually and become effective each January 1. The Uncollectible Bill Percentage shall be based on the Company's actual uncollectible bill experience applicable to electric and gas customers for the 12-month period through the previous September. The Risk Factor shall be equal to 15 percent of the Uncollectible Bill Percentage. The Credit and Collections component will include: a) a percentage determined by dividing the Company's credit and collection expenses attributable to firm transportation customers whose ESCOs/Marketers participate in the Company's POR program by the estimated gas supply costs to be billed on behalf of ESCOs/Marketers through the POR program; and b) effective January 1, 2019, a percentage that reflects a reconciliation of prior periods' credit and collections expenses and recoveries ("C&C Variation"), plus interest (calculated at the Other Customer Capital Rate). The Incremental Cost component shall be set at 0.15%.

A statement showing the POR Discount Percentage will be filed with the Commission on no less than three days' notice.

(Service Classification No. 20 - Continued on Leaf No. 397.3)

SERVICE CLASSIFICATION NO. 20 - Continued

TRANSPORTATION RECEIPT SERVICE (TRS) - Continued

Miscellaneous Provisions - Continued

(P) Consolidated Billing and Payment Processing Services - Continued

A statement showing the POR Discount Percentage is filed with the Commission on no less than three days' notice.

Further details of the POR program are described in the Company's Operating Procedures and the Billing Service Agreement between the Company and the ESCO/Marketer.

A Marketer Consolidated Bill shall include a bill issued by a Marketer under agency billing, until Electronic Data Interchange ("EDI") is operational for bill-ready Marketer consolidated billing, as permitted in the Operating Procedures. A Marketer that fails to bill its customers or to transmit Customer payments to Con Edison on a timely basis will be precluded from acting as a Billing Agent. When EDI is operational for Marketer consolidated billing, as established in Case 99-M-0667, all provisions of this Rate Schedule relating to Billing Agency are terminated.

For Marketer Consolidated Bills issued on or after February 3, 2004, Customer payments shall be allocated and prorated in accordance with the UBP, the Home Energy Fair Practices Act (Public Service Law, Article 2), and applicable orders of the Commission.

If a Marketer requests that a Company-issued Consolidated Bill include an insert required by statute, regulation, or Public Service Commission order, and such insert exceeds one-half ounce, the Company will charge the Marketer for incremental postage.

(Q) Discontinuance and Suspension of Transportation Service to a Customer

A Marketer may not physically disconnect a Customer's gas service. Con Edison may disconnect service to a Customer in accordance with the provisions of the General Information Section of this Rate Schedule. At the request of a Marketer, Con Edison may suspend service to a residential Customer or a two-family dwelling receiving Marketer Consolidated Bills or to a multiple dwelling pursuant to the Home Energy Fair Practices Act (Public Service Law, Article 2) ("HEFPA"). However, the Marketer may not request service suspension in the condition where the Company is purchasing the Marketer's receivables.

By submitting a request for suspension of service to the Company in the authorized form, a Marketer represents that it has complied with all statutory and regulatory requirements for termination of supply service and suspension of transportation service. Suspension will end at the request of the Marketer that requested the suspension. However, if the Marketer has not requested an end to the suspension one year after it terminated supply service, the Company will restore delivery service at the Customer's request provided the Customer meets tariff and HEFPA requirements for service restoration.

(Service Classification No. 20 - Continued on Leaf No. 398)

NYS DEPARTMENT OF STATE

Notice of Proposed Rule Making

Public Service Commission
(SUBMITTING AGENCY)

NOTE: Typing and submission instructions are at the end of this form. Please be sure to COMPLETE ALL ITEMS. Incomplete forms and nonscannable text attachments will be cause for rejection of this notice.

Pursuant to the provisions of the State Administrative Procedure Act (SAPA), NOTICE is hereby given of the following agency action:

1. Proposed action:

The Public Service Commission (the "PSC") is considering whether to approve, reject, in whole or in part, or modify a proposal filed by Consolidated Edison Company of New York, Inc. (the "Company") to make various changes in the charges, rules, and regulations contained in its Schedule for Electricity Service, P.S.C. No. 10 –ELECTRICITY and in its Schedule for PASNY Delivery Service – P.S.C. No. 12 – ELECTRICITY, effective January 1, 2023.

2. Statutory authority under which rule is proposed:

N/A

3. Subject of rule:

Tariff leaves reflecting increases in the rates and charges contained in the Company's Schedule for Electricity Service, P.S.C. No. 10 – ELECTRICITY and in its Schedule for Electricity Service – P.S.C. No. 12 – ELECTRICITY.

4. Purpose of rule:

Consideration of tariff changes reflecting an increase in electric revenues of approximately $1,199 million for the rate year, the twelve months ending December 31, 2023. In addition, proposals have been made in the tariffs for various provisions.

5. Terms of rule (check applicable box):

[ ] The rule contains 2,000 words or less. An original copy of the text in scannable format is attached to this form.

[ ] The rule contains more than 2,000 words. Therefore, an original copy of a summary the text (in scannable format) is attached to this form.

[X] Pursuant to SAPA § 202(7)(b), the agency elects to print a description of the subject, purpose and substance of the rule containing less than 2,000 words. The original text in scannable format is attached to this form.

6. The text of the rule and any required statements or analyses may be obtained from:

Name of agency contact Margaret Maguire, Clerk II

Office address Three Empire State Plaza
Albany, New York 12223

Telephone number (518) 474-3204

7. Regulatory Impact Statement (RIS) (check applicable box):

[ ] A RIS of 2,000 words or less is submitted with this notice.

[ ] A summary of the RIS is submitted with this notice because the full text exceeds 2,000 words.

[ ] A consolidated RIS is submitted with this notice because:

[ ] the rule is one of a series of closely related and simultaneously proposed rules.

[ ] the rule is one of a series of virtually identical rules proposed during the same year.

[ ] An RIS is not submitted because this rule is a technical amendment and, therefore, exempt from SAPA § 202-a. Attached to this notice is a statement of the reason(s) for claiming this exemption.

[ ] An RIS is not submitted because this rule is subject to a consolidated RIS printed in the Register under a notice of proposed rule making ID No. PSC-_______; Register date: _________.

[X] An RIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

8. Regulatory Flexibility Analysis for Small Businesses (RFASB) (check applicable box):

[ ] An RFASB of 2,000 words or less is submitted with this notice.

[ ] A summary RFASB is submitted with this notice because the full text exceed 2,000 words.

[ ] A consolidated RFASB is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject of the same analysis.

[ ] An RFASB is not submitted because this rule will not impose any adverse economic impact or reporting, recordkeeping or other compliance requirements on small businesses. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse economic impact or compliance requirements on small businesses.

[ ] An RFASB is not submitted because this rule is subject to a consolidated RFASB printed in the Register under a notice of proposed rule making, ID No. _______; Register date: _________.

[X] An RFASB is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

9. Rural Area Flexibility Analysis (RAFA) (check applicable box):

[ ] An RAFA of 2,000 words or less is submitted with this notice.

[ ] A summary RAFA is submitted with this notice because the full text exceeds 2,000 words.

[ ] A consolidated RAFA is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject to the same analysis.

[ ] An RAFA is not submitted because this rule will not impose any adverse impact or reporting, recordkeeping or other compliance requirements on public or private entities in rural areas. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse impact or compliance requirements on rural areas.

[ ] An RAFA is not submitted because this rule is subject to a consolidated RAFA printed in the Register under a notice of proposed rule making, ID No. ______; Register date: _________.

[X] An RAFA is not submitted because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

10. Job Impact Statement (JIS) (check applicable box):

[ ] A JIS of 2,000 words or less is submitted with this notice.

[ ] A summary JIS is submitted with this notice because the full text exceeds 2,000 words.

[ ] A JIS/Request for Assistance is submitted with this notice.

[ ] A consolidated JIS is submitted with this notice because this rule is the first of a series of closely related rules that will be subject to the same analysis.

[ ] A JIS is not submitted because it is apparent from the nature and purpose of the rule that it will not have a substantial adverse impact on jobs and employment opportunities. A statement is attached setting forth this agency's finding that the rule will have a positive impact or no impact on jobs and employment opportunities; except when it is evident from the subject matter of the rule that it could only have a positive impact or no impact on jobs and employment opportunities, the statement shall include a summary of the information and methodology underlying that determination.

[ ] A JIS is not submitted because this rule is subject to a consolidated JIS printed in the **Register** in a notice of proposed rule making ID No. _________; Register date: _________.

[X] A JIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

[ ] A JIS is not submitted because this rule is proposed by the State Comptroller or Attorney General.

11. Prior emergency rule making for this action was previously published in the ______ issue of the Register, I.D. No. __________.

12. Expiration Date (check only if applicable):

    [X] This proposal will not expire in 180 days because it is for a "rate making" as defined in SAPA § 102(2)(a)(ii).

13. Public Hearings (check box and complete as applicable)

    [ ] A public hearing is required by law and will be held at __ a.m./p.m. on ________, 19__, at

    [ ] A public hearing is not required by law, and has not been scheduled.

    [ ] A public hearing is not required by law, but will be held at __ a.m./p.m. on _______, 19 __, at

14. Interpreter Service (check only if a public hearing is scheduled):

    [ ] Interpreter services will be made available to hearing impaired persons, at no charge, upon written request submitted within a reasonable time prior to the scheduled hearing. Requests must be addressed to the agency contact designated in this notice.

15. Accessibility (check appropriate box only if a public hearing is scheduled):

    [ ] All public hearings have been scheduled at places reasonably accessible to persons with a mobility impairment.

    [ ] All public hearings except the following have been scheduled at places reasonably accessible to persons with a mobility impairment:
    1.
    2.
    3.

    [ ] None of the scheduled public hearings are at places that are reasonably accessible to persons with a mobility impairment.

    [ ] An **optional** explanation is being submitted regarding the nonaccessibility of one or more hearing sites.

16. Submit data, views or arguments to (complete only if different than previously named agency contact):

    Name of agency contact Hon. Michelle L. Phillips, Secretary
    Office address Three Empire State Plaza
    Albany, New York 12223
    Telephone number (518) 474-6530

17. Additional matter required by statute:

    [X] Check box if NOT applicable.

18. Public comment will be received until:

    [ ] 45 days after publication of this notice (MINIMUM, public comment period).

    [ ] 5 days after the last scheduled public hearing required by statue (MINIMUM, with required hearing).

    [ ] Other: (specify) ___________________.

19. Regulatory Agenda: (**The Division of Housing and Community Renewal; Workers Compensation Board; and the departments of Agriculture and Markets, Banking, Education, Environmental Conservation, Health, Insurance, Labor and Social Services** and any other department specified by the governor or his designee must complete this item. If your agency had an optional agenda published, that should also be indicated below):

    [ ] This action was listed as a Regulatory Agenda item in the first January issue of the Register, 19_.

    [ ] This action was listed as a Regulatory Agenda item in the last June issue of the Register, 19_.

    [ ] This action was not under consideration at the time this agency's Regulatory Agenda was submitted for publication in the Register.

AGENCY CERTIFICATION (To be completed by the person who PREPARED the notice)

I have reviewed this form and the information submitted with it. The information contained in this notice is correct to the best of my knowledge.

I have reviewed Article 2 of SAPA and Parts 260 through 263 of 19 NYCRR, and I hereby certify that this notice complies with all applicable provisions.

Name ___________________________ Signature
Address
Date ___________________________ Telephone

Please read before submitting this notice:

1. Except for this form itself, all text must be typed in scannable format as described in the Department of State's "NYS Register Procedures Manual."

2. Submit the **orginal notice and scanner copy** collated as (1) form; (2) text or summary of rule; and if any, (3) regulatory impact statement, (4) regulatory flexibility analysis for small businesses, (5) rural area flexibility analysis, (6) job impact statement **- and ONE copy of that set.**

3. **Hand deliver to:** DOS Office of Information Services, 41 State Street (3rd Floor), Albany
   Address mail to: Register/NYCRR unit, Department of State, Albany, NY 12231

NYS DEPARTMENT OF STATE

Notice of Proposed Rule Making

Public Service Commission
(SUBMITTING AGENCY)

NOTE: Typing and submission instructions are at the end of this form. Please be sure to COMPLETE ALL ITEMS. Incomplete forms and nonscannable text attachments will be cause for rejection of this notice.

Pursuant to the provisions of the State Administrative Procedure Act (SAPA), NOTICE is hereby given of the following agency action:

1. Proposed action:

   The Public Service Commission (the "PSC") is considering whether to approve, reject, in whole or in part, or modify a proposal filed by Consolidated Edison Company of New York, Inc. (the "Company") to make various changes in the charges, rules, and regulations contained in its Schedule for Gas Service, P.S.C. No. 9 – GAS, effective January 1, 2023.

2. Statutory authority under which rule is proposed:

   N/A

3. Subject of rule:

   Tariff leaves reflecting increases in the rates and charges contained in the Company's Schedule for Gas Service, P.S.C. No. 9 – GAS.

4. Purpose of rule:

   Consideration of tariff changes reflecting an increase in gas revenues of approximately $503 million for the rate year, the twelve months ending December 31, 2023. In addition, proposals have been made in the tariffs for various provisions.

5. Terms of rule (check applicable box):

   [ ] The rule contains 2,000 words or less. An original copy of the text in scannable format is attached to this form.

   [ ] The rule contains more than 2,000 words. Therefore, an original copy of a summary the text (in scannable format) is attached to this form.

   [X] Pursuant to SAPA § 202(7)(b), the agency elects to print a description of the subject, purpose and substance of the rule containing less than 2,000 words. The original text in scannable format is attached to this form.

6. The text of the rule and any required statements or analyses may be obtained from:

   Name of agency contact: Margaret Maguire, Clerk II

   Office address: Three Empire State Plaza
   Albany, New York 12223

   Telephone number: (518) 474-3204

7. Regulatory Impact Statement (RIS) (check applicable box):

[ ] A RIS of 2,000 words or less is submitted with this notice.

[ ] A summary of the RIS is submitted with this notice because the full text exceeds 2,000 words.

[ ] A consolidated RIS is submitted with this notice because:

[ ] the rule is one of a series of closely related and simultaneously proposed rules.

[ ] the rule is one of a series of virtually identical rules proposed during the same year.

[ ] An RIS is not submitted because this rule is a technical amendment and, therefore, exempt from SAPA § 202-a. Attached to this notice is a statement of the reason(s) for claiming this exemption.

[ ] An RIS is not submitted because this rule is subject to a consolidated RIS printed in the Register under a notice of proposed rule making ID No. PSC-_______; Register date: _________.

[X] An RIS is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

8. Regulatory Flexibility Analysis for Small Businesses (RFASB) (check applicable box):

[ ] An RFASB of 2,000 words or less is submitted with this notice.

[ ] A summary RFASB is submitted with this notice because the full text exceed 2,000 words.

[ ] A consolidated RFASB is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject of the same analysis.

[ ] An RFASB is not submitted because this rule will not impose any adverse economic impact or reporting, recordkeeping or other compliance requirements on small businesses. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse economic impact or compliance requirements on small businesses.

[ ] An RFASB is not submitted because this rule is subject to a consolidated RFASB printed in the Register under a notice of proposed rule making, ID No. _______; Register date: _________.

[X] An RFASB is not submitted with this notice because this rule is a "rate making" as defined in SAPA § 102(2)(a)(ii).

9. Rural Area Flexibility Analysis (RAFA) (check applicable box):

[ ] An RAFA of 2,000 words or less is submitted with this notice.

[ ] A summary RAFA is submitted with this notice because the full text exceeds 2,000 words.

[ ] A consolidated RAFA is submitted with this notice because this rule is the first of a series of closely related rules that will be the subject to the same analysis.

[ ] An RAFA is not submitted because this rule will not impose any adverse impact or reporting, recordkeeping or other compliance requirements on public or private entities in rural areas. A statement is attached setting forth this agency's finding and the reasons upon which the finding was made, including what measures were used by this agency to ascertain that this rule will not impose such adverse impact or compliance requirements on rural areas.

[ ] An RAFA is not submitted because this rule is subject to a consolidated RAFA printed in the Register under a notice of proposed rule making, ID No. ______; Register date: _________.

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10. Job Impact Statement (JIS) (check applicable box):

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I have reviewed Article 2 of SAPA and Parts 260 through 263 of 19 NYCRR, and I hereby certify that this notice complies with all applicable provisions.

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3. **Hand deliver to:** DOS Office of Information Services, 41 State Street (3rd Floor), Albany
   Address mail to: Register/NYCRR unit, Department of State, Albany, NY 12231

Method of Service

Name:	Richard Miller
Company/Organization:	Consolidated Edison Company of New York, Inc.
Mailing Address:	18th Floor, 4 Irving Place, New York, NY 10003
Company/Organization you represent, if different from above:	
E-Mail Address:	Millerrich@coned.com
Case/Matter Number:	

Request Type

- ■ New Petition/Application - I am filing a new petition/application which requires action by the Commission.
- ☐ Service List request – I request to be on the service list for the matter/case.
- ☐ Other – Type of request ____

Service Information *(Select one option below)*

- ■ Electronic Service and Waiver – Consent in Case/Matter Identified Above
  As duly authorized by the Participant identified above that I represent, I knowingly waive on behalf of that Participant any right under PSL §23(1) to be served personally or by regular mail with Commission orders that affect that Participant and will receive all orders by electronic means in the above Case. If participating individually, I knowingly waive any PSL §23(1) right to service of orders personally or by regular mail and will receive all orders by electronic means in the above Case. This consent remains in effect until revoked.

- ☐ Electronic Service and Waiver – Global Consent in All Cases/Matters
  As duly authorized by the Participant identified above that I represent, I knowingly waive on behalf of that Participant any right under PSL §23(1) to be served personally or by regular mail with Commission orders that affect that Participant and will receive all orders by electronic means in all Cases where it participates. If participating individually, I knowingly waive any PSL §23(1) right to service of orders personally or by regular mail, and will receive all orders by electronic means in all Cases where I participate. This consent remains in effect until revoked.
  ***Note**: Due to the design of our system, this consent attaches to the individual named here and not to the party that may be represented by that individual. Therefore, individuals who represent multiple parties should be aware that a global consent will affect all matters in which they appear on behalf of any party.*

- ☐ I do **not** consent to receive orders electronically

E-Mail Preference *(Select one option below) – For Case specific request*
E-Mail notifications include a link to filed and issued documents.

- ☐ Notify me of Commission Issued Documents in this case/matter.
- ■ Notify me of Both Commission Issued Documents and Filings in this case/matter
- ☐ Do not send me any notifications of filed or issued documents

Submitted by: Richard MIller	Date: 1/28/2022

Table of Contents

I. Introduction

Q. Would the members of the Customer Energy Solutions ("CES") Panel please state their names and business addresses?

A. Alexander Buell, Greg Elcock, Vicki Kuo, Thomas Magee, Nickolas Hellen, Leonard P. Singh, Shaun Smith, and Stephen Wemple. Our business address is 4 Irving Place, New York, NY, 10003.

Q. In what capacity are the panel members employed and what are their professional backgrounds and qualifications?

(Buell) I am Alexander Buell, Director of Portfolio Planning and Analysis and responsible for the strategy, business planning, data and analytics, and stakeholder outreach of Energy Efficiency and Demand Management. I have almost 15 years of experience in strategy, planning, and energy. Prior to my current role at the Company, I was Department Manager in the Utility of the Future, and Department Manager of Strategy & Planning in Energy Efficiency and Demand Management. Before joining the Company in 2015, I was an Engagement Manager at McKinsey & Company working across strategy and marketing & sales for clients in energy, power, heavy manufacturing, and government. I began my career at Good Energies, a clean technology private equity firm. I have a Masters of Business Administration with a focus in Finance from the Wharton School of the University of Pennsylvania, and a Bachelors of Arts in English Literature from Yale University.

(Elcock) I am Gregory Elcock, Director of Energy Efficiency and Demand Management. I am responsible for the direction and execution of the energy efficiency products and programming. I previously served in several different capacities within Con Edison including Manager, Energy Efficiency Programs; Section Manager, Strategic Services; Department Manager, Distributed Resource Integration; and Director, State Regulatory Affairs. Before joining Con Edison in 2009, I worked for the Community Environmental Center (“CEC”) for over 10 years, where I was responsible for managing the organization’s multifamily energy efficiency businesses in New York City and a diversified range of other state and city energy efficiency contracts. I have a Masters of Science degree in Sustainability

Management from Columbia University and a Masters of Science degree in Energy Management from New York Institute of Technology. I obtained my baccalaureate degree in Economics from the University of the West Indies, Trinidad and Tobago.

(Hellen) I am Nickolas Hellen, Chief Engineer of Gas Distribution Engineering. I lead a team in Gas Engineering responsible for Integrity Management, Standards and Regulatory Issues, System Reliability and Maps and Records. Prior to my current position, I held numerous positions in increasing responsibility in operations and engineering across two commodities, Electric and Gas, including an Electric Operating Supervisor, Electric Operating General Supervisor, Gas Operations Construction Planner, Gas Engineering Manager, Gas Construction Manager, Gas Emergency Response Center Department Manager, and Department Manager in Energy Efficiency Demand Management. I hold a Bachelor’s degree in Mechanical Engineering from the Cooper Union, and a Masters of Business Administration with a focus in Finance, Leadership/Change Management and Strategy from NYU Stern. I have also completed PTI’s Electric Distribution

System Engineering Course, and GTI’s Registered Gas Distribution Professional Course.

(Kuo) I am Vicki Kuo, Vice President, Energy Efficiency and Distribution Resource Planning (“EEDRP”). I am responsible for the Company’s energy efficiency (“EE”), demand response (“DR”), distribution planning, distributed resource integration, non-wires solutions (“NWS”) and non-pipeline solutions (“NPS”) programs. I have been in my current position since 2019. I have been employed by Con Edison for 23 years in a variety of positions with increasing responsibility within Electric Operations, Strategic Planning, IT, and with Con Edison Development. I also have 10 years of experience building new products and developing new markets outside of the utility industry in both North America and Europe. I hold a Bachelor of Science degree in Electrical Engineering and a Masters degree in Management from NYU Polytechnic School of Engineering.

(Magee) I am Tom Magee, General Manager of the AMI Implementation Team. I am the business lead for the Company’s AMI Project. The AMI Project scope includes a full-scale rollout of AMI smart meters and supporting infrastructure for the Company's electric and gas customers. I have been in this position since 2015. I have been employed by Con Edison for 37 years. I have held various positions including Watch Supervisor, Ravenswood Generating Station; Associate Engineer, Electrical Engineering; and Engineer, Fossil Power Engineering. I have also served as Project Manager, Energy Management – Power Plant Divestiture; Section Manager, Steam Distribution Engineering; Section Manager, East River Repowering Project, Technical Manager, East River Generating Station; and General Manager, Smart Grid Implementation Group. I hold a Bachelor of Science degree in Marine Engineering from the U.S. Merchant Marine Academy.

(Singh) I am Leonard Singh. I have been the Senior Vice President of Customer Energy Solutions since 2021. I lead a team responsible for distributed resource integration into infrastructure planning, battery storage, EE, rate design, heating electrification and electric vehicle initiatives, non-wires and non-pipeline solutions, Utility of the Future, as well as the implementation of the company's smart meter program, its new customer information system, the integrated data energy resource, and data access framework. Prior to my current position, I held numerous positions in operations and engineering across the Company's three commodities (Electric, Gas, and Steam) since joining the company in 1991, including an Operating Supervisor, Construction Manager, Chief Engineer, General Manager, and Vice President, with increasing responsibility and breadth. I hold a Bachelor of Science in Electrical Engineering from Massachusetts Institute of Technology, Master of Science in Electrical Engineering from Brooklyn Polytechnic University, and a Master of Business Administration from Columbia University.

(**Smith**) I am Shaun Smith, Director of Distributed Resource Integration/Planning. I oversee the operations of the Company's Distributed System Platform ("DSP") – the tools, technologies, and employees working to integrate DER into the planning and operations of our electricity systems. As part of this role, which I started in January 2022, I oversee the Company's electric distribution planning organization that brings DER together with traditional infrastructure to meet customers' needs for energy amid New York's clean energy transition. Since starting in the Company in 2003, I served in several different capacities within Con Edison, taking on roles of increasing responsibility, including Engineering Supervisor, Brooklyn & Queens ("BQ") Electric Operations; Operating Supervisor and Field Operations Planner, BQ Field/Substations Operations; Section Manager, BQ Overhead and Services; Senior System Operator, System & Transmission Operations; General Manager, Manhattan Electric Operations; and most recently General Manager, Manhattan Electric Construction. I have a Bachelor of Electrical Engineering from City University of New York, a Master of Science in Electrical Engineering from Manhattan College, and a Master of Business Administration from New York University.

(Wemple) I am Stephen Wemple, General Manager of the Utility of the Future team. I am responsible for the Company's initiatives to develop new business models and compensation mechanisms to promote the installation and operation of clean energy technologies necessary to meet the state’s policy goals. I have been in this position since 2016. I have been employed by Con Edison for 34 years and have held various positions in both the Clean Energy Businesses as well as at the Company. I hold a Bachelor of Science degree and a Masters in Engineering degree from Cornell University.

Q. Have panel members previously testified before the New York State Public Service Commission?

A. Ms. Kuo and Mr. Magee have submitted testimony or testified before the Commission in prior proceedings. Messrs. Buell, Elcock, Hellen, Singh, Smith, and Wemple have not previously submitted testimony or testified before the Commission.

II. Overview of CES Group

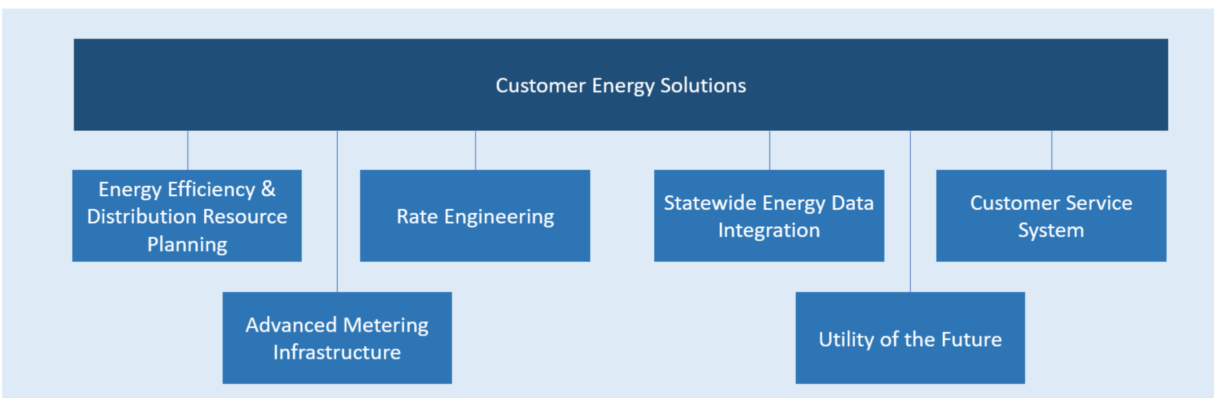
Q. Please explain the function of Customer Energy Solutions (“CES”).

A. CES develops, implements, and operates the programs, tools, and customer support technologies for the clean energy transition. CES also integrates distributed energy resources

("DER") into the Company's energy systems and plans to address future infrastructure needs. Groups within CES implement the Company's EE, demand management ("DM"), NWS, NPS, electric vehicle ("EV"), energy storage, distributed energy, demonstration projects, rate design, DSP, AMI, and new Customer Service System ("CSS") development.

Q. How is CES structured and what are the general responsibilities of each function?

A. CES is structured as follows:



Within the **Energy Efficiency & Distribution Resource Planning** group, the Demand Management team implements the Company's Demand Response, NWS, and NPS programs, as authorized through a variety of proceedings. The **Distributed Resource Planning** group plans upgrades to the Company's electric distribution system, implements the DSP, and supports customers installing DER. The **E-Mobility and Demonstration Projects** group implements the EV Charging Make Ready program authorized in the Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure[1] (the "EVSE Proceeding"), managed charging, and the Company's demonstration projects as authorized in the Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision ("REV").[2] The **EE group** implements EE and heating electrification programs authorized via the proceeding In the Matter of a Comprehensive Energy Efficiency Initiative[3] (the "New Efficiency New York Proceeding" or "NENY Proceeding").

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[1] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure.*

[2] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*.

[3] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative.*

Rate Engineering maintains the Company’s tariffs, calculates rates, and conducts cost of service and cost allocation studies for electric, gas, and steam.

The **Statewide Energy Data Integration** group works with New York State Department of Public Service (“DPS”) Staff and stakeholders to develop, provide, and maintain energy data for third party use through the New York Public Service Commission’s (“PSC”) Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data.[4]

The **Customer Service System** (“CSS”) group oversees the design, build, and implementation of the Company’s new customer service system. Once complete, the ongoing management of this system will move to Customer Operations. Since the Company will launch the new CSS during the rate year, program changes for CSS-related investments are discussed in the Customer Operations Panel.

[4] Case 20-M-0082, *Proceeding on Motion of the Commission Regarding Strategic Use of Energy Related Data.*

The **AMI** group handles the Company’s roll out of advanced meters and metering systems.

The **Utility of the Future** group is responsible for developing new business models and compensation mechanisms to promote the distributed and clean energy resources necessary to meet the State’s policy goals. Specifically, the group advocates for and oversees the implementation of incentives for clean and renewable resources eligible for Value of Distributed Energy Resources (“VDER”) and Remote Crediting compensation and for procuring energy storage projects, including the bulk storage procurements authorized via the proceeding In the Matter of Energy Storage Deployment Program[5] (the “Energy Storage Proceeding”).

III. <u>Purpose of Testimony</u>

Q. What is the purpose of this testimony?

A. This testimony proposes programs and investments to advance achievement of New York State clean energy policy

[5] Case 18-E-0130, *In the Matter of Energy Storage Deployment Program.*

objectives, which are aligned with similar City of New York objectives. Our proposals accomplish these objectives by integrating DER into our energy systems, engaging customers to manage their energy use, expanding clean energy access in Disadvantaged Communities and for low- and moderate-income customers ("LMI"), and supporting our energy systems' resilience and reliability. These proposals are incremental to funds previously authorized for our other clean energy programs. Examples of the proposed investments include:

- Make-ready programs that will offset the costs of customer behind-the-meter electrical work needed to enable electrification of heating and appliances, and electrical work needed to integrate DER in Disadvantaged Communities;
- Customer tools that will help customers understand clean energy options, including the costs and benefits of these options, and engage the market to adopt the solutions;

- A renewable solar generation program that will stream benefits to low-income customers through a bill credit; and
- Alternative infrastructure programs that will advance the integration of DER into our energy systems and maximize the benefits they bring to all customers.

Q. Why are these investments necessary?

A. The CLCPA Panel describes the Company's support for New York's clean energy goals and its Clean Energy Commitment. Achieving the targets outlined in the Climate Leadership and Community Protection Act ("CLCPA") legislation requires Con Edison to play a leading role in partnering with stakeholders to collectively invest in a low-carbon future.

Over the past several years, the clean energy market in New York has made great strides. For example, between 2017-2021, the Company worked with customers and the market to interconnect 220 MW of solar, achieved incremental reductions of over 2,400 GWh and 2.6 million Dth in EE, and installed over 28,000 cold climate heat pumps through the NYS Clean Heat program. The next few years will be crucial to accelerate this growth for an effective transition. Our proposed investments support customers and third-party clean energy businesses by (1) reducing upfront costs of clean energy projects; (2) facilitating solutions; and (3) engaging Disadvantaged Communities and low-income customers in the clean energy transition.

Q. What period does this testimony cover?

A. The twelve-month period ending December 31, 2023 ("Rate Year" or "RY1") and, if there is a three-year rate plan, the twelve-month periods ending December 31, 2024 ("RY2") and December 31, 2025 ("RY3").

Q. Please summarize the programs outlined in this testimony and their associated costs.

A. We propose capital funding of $165.7 million for RY1, $246.4 million in RY2, and $236.1 million in RY3. The proposed capital funding includes projects that are detailed either in this testimony or in exhibits in the IT panel (RY1 $90.6 million, RY2 $89.9 million, and RY3 $89.4 million).

Q. Please provide an overview of the capital expenditures.

A. Table 1 presents the projected capital costs for the programs described that are not already addressed through established budgets and collection methods (e.g., the Company's EV Charging Make Ready program).

The 2023 capital request is $165.7 million, a $58 million decrease from 2022. The main drivers are lower AMI costs ($105 million) since most meters are installed, offset by increases in new investments such as the Customer Recommendation and Analysis Tools ($12 million), DER Make-Ready Program for Disadvantaged Communities and Low-Income Customers ($6 million), DSP ($2 million), DER Integration and Management Program ($16 million) and Energy Storage ($11 million).

The 2024 capital request is $246.4 million, a $80 million increase from 2023. The main driver for the 2024 increase is the investment in the new Clean Energy Credit for Low Income Customers program ($100 million).

The 2025 capital request is $236.1 million, a $10 million decrease from 2024. The main driver is DER Make-Ready

Program for Disadvantaged Communities and Low-Income Customers ($10 million).

Table 1: Capital Expenditures ($000)

Program	**2023**	**2024**	**2025**	**Rate Period ('23-'25)**
DER Make Ready for Disadvantaged Communities and Low-Income Customers	$5,900	$14,800	$5,000	$25,700
Clean Energy Credits for Low Income Customers	$0	$100,000	$100,000	$200,000
Energy Storage Installation & Operation	$37,701	$41,702	$41,702	$121,105
AMI	$31,466	$0	$0	$31,466
Total CES	**$75,067**	**$156,502**	**$146,702**	**$378,271**
Programs in IT Panel				
Customer Recommendation and Analysis Tools*	$12,000	$12,000	$11,000	$35,000
Distributed System Platform, including CVO*	$62,160	$62,600	$63,100	$187,860
DER Integration and Management Program*	$16,485	$15,250	$15,250	$46,985
Total IT	**$90,645**	**$89,850**	**$89,350**	**$269,845**
Grand Total	**$165,712**	**$246,352**	**$236,052**	**$648,116**

**These projects are described in this testimony but fully detailed in exhibits in the IT Panel. The spend for these is included in the IT panel summaries as well.*

Q. Please explain the Panel’s O&M forecast.

A. Table 2 presents the associated O&M expenditures for each of the programs described that do not have an established budget and collection method (*e.g.*, EE, EV make-ready). For O&M, we are requesting $40 million in incremental expenditures in RY1, an additional $4 million in RY2, and another additional $5 million in RY3.

The RY1 increase is driven by O&M associated with capital projects, including AMI, DSP, and Information System and Operational Software Upgrades ($23 million), and staffing to meet increasing EE goals, such as the statewide heat pump and low-income programs ($10 million).

The main driver for the request increase in RY2 is energy efficiency staffing ($4 million).

The main driver for the request increase in RY3 is the operation of the new energy storage projects ($5 million).

Table 2: O&M Expenses ($000)

Program	2023	2024	2025	Rate Period ('23-'25)
DER Make Ready for Disadvantaged Communities and Low-Income Customers	$240	$240	$240	$720
Innovative Pricing Pilot Expansion	$5,452	$5,358	$4,488	$15,298
Energy Storage Installation & Operations	$2,232	$2,316	$6,446	$10,994
Energy Storage Market Development & Implementation	$815	$1,287	$1,460	$3,562
AMI	$49,217	$50,201	$51,205	$150,623
Energy Efficiency and Targeted Demand Management	$27,543	$30,187	$32,407	$90,137
EV Market and Technology Development	$1,010	$1,010	$1,010	$3,030
Utility of the Future Development	$2,221	$2,287	$2,356	$6,864
Customer Recommendation and Analysis Tools	$5,500	$5,000	$4,000	$14,500
Distributed System Platform, including CVO	$3,500	$3,300	$2,500	$9,300
DER Integration and Management Program	$3,500	$3,570	$3,640	$10,710
Total O&M	**$101,230**	**$104,756**	**$109,752**	**$315,738**

Q. Is the Panel requesting that any program expenditures be treated as a regulatory asset?

A. Yes. The Company proposes to record the Smart Inverter expenditures in the DER Integration & Management Program and the Heating Electrification Make-Ready expenditures presented in Table 3 as regulatory assets to be amortized over 15- and 10-year periods respectively. Existing programs receiving regulatory asset treatment are noted later.

Table 3: Proposed Regulatory Asset Expenditures

Item	**2023**	**2024**	**2025**
Heating Electrification Make-Ready	$14,200	$24,700	$37,700
DER Integration and Management Program	$3,000	$10,000	$12,000
Total	**$17,200**	**$34,700**	**$49,700**

Q. Please quickly explain what is meant by Regulatory Asset treatment.

A. A regulatory asset is cost recovery authorized by a regulatory agency that allows a utility to capitalize a cost that would otherwise be expensed and recover it over time. For the above programs that help customers offset the costs of capital upgrades that aid the clean energy transition, treating program costs similar to capital investments advances policy objectives and/or provides customer benefits. These include moderation of customer bill impacts through amortization of costs to align customer costs with the realization of customer benefits over time. The

Commission has approved regulatory asset treatment for EE in prior Con Edison rate cases, and in the Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs.[6]

Q. Please describe previously approved expenditures for Energy Efficiency and EV Make-Ready charging?

A. The Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 ("NENY Order")[7] and the Make-Ready Program Order[8] respectively authorize program investments in a) EE and heating electrification, and b) EV charging infrastructure make-ready. Planned expenditures to be recovered as regulatory assets during this rate period are below:

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[6] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* (EVSE&I Proceeding), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020).

7 Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative, Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (*Issued January 16, 2020).

[8] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure,* Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (Issued July 16, 2020).

Table 4: Previously Approved Energy Efficiency & Heating Electrification and Electric Vehicle Make-Ready Expenditures

($000s)

Item	2023	2024	2025
NENY[9]	$297,406	$387,120	$171,036
EV Make-Ready Program	$ 51,387	$ 67,749	$ 77,787

IV. Supporting Customer Participation in the Clean Energy Transition

Q. Please explain the "clean energy transition."

A. By clean energy transition, we mean the State's move away from carbon-intensive energy to renewable energy and clean energy technologies, like storage and EE. The Company intends to help the State and the City of New York achieve

[9] The Company forecasts $73 million of unspent funds authorized to fund NENY programs under the NENY Order will be spent in 2023 in addition to the regulatory asset amount in this table.

their ambitious clean energy goals, as outlined in the CLCPA, as well as New York City policies.[10] Making and ultimately achieving this transition and realizing its benefits will require significant utility investment.

Q. How is the Company supporting customers in the clean energy transition?

A. The Company supports customers’ transition to clean energy through a variety of programs and offerings designed to help them make informed decisions about their clean energy options and reduce the upfront costs of installing clean energy technologies. Current offerings include the Company’s EE programs, heating electrification program, EV charging make-ready program, managed charging program, demand response offerings, energy storage solicitations, and support for customers seeking to install on-site solar and other DER.

We plan to increase our offerings during the next three years. In this section, we discuss several programs to

[10] *E.g.,* New York City Local Law 66 of 2014.

complement existing ones and assist with the transition, including a “make ready” incentive program for electrical upgrades to assist customers as they electrify their heating, tools to assist customers to better understand and analyze their clean energy options, purchasing solar facilities to provide clean energy bill discounts to low-income customers, and tools to help integrate distributed clean energy into energy systems.

Q. Can customers in Disadvantaged Communities receive the benefits of the clean energy transition?

A. Yes. We plan to build on existing programs and launch new ones to facilitate their participation in the clean energy transition. This also applies to LMI customers.

Q. What is the Company currently doing to support Disadvantaged Community and low-income customer participation in the clean energy transition?

A. In addition to general programs these customer groups can access, the Company runs programs specifically focused on these customer groups. For example, EE incentivizes multi-family buildings that house LMI customers to pursue comprehensive EE upgrades. Additionally, through-our EV make-ready program, we offer higher levels of support, up to 100% of make-ready costs, for eligible EV charging stations in a specified Disadvantaged Community Zone.

Q. Is the Company proposing additional programs to assist Disadvantaged Communities and low-income customers in participating in the clean energy transition?

A. Yes. Given where we are in the transition, it is important to accelerate efforts now to bring the benefits of clean energy to Disadvantaged Communities and low-income customers generally. This filing proposes two new programs encompassing $225 million of investment dedicated to Disadvantaged Communities and LMI customers, including a “make ready” program for these customers to reduce the interconnection costs for clean distributed energy, and purchasing solar facilities to provide clean energy bill discounts to low-income customers. The filing also proposes expanding eligibility for electric EE and heat pump programs to New York Power Authority (“NYPA”) customers, including the New York City Housing Authority (“NYCHA”), New York City schools, City-run community centers and housing shelters. Additionally, the proposed Heating Electrification Make-Ready program includes enhanced incentives specifically for customer-sided electrical upgrades in LMI buildings.

A. Heating Electrification Make-Ready Program

Q. Please describe heating electrification and the transition customers must undertake to move from fossil-fueled heating.

A. Currently, many customers heat their homes and businesses with fossil fuels, like oil, propane, and natural gas. To achieve CLCPA-mandated emissions reductions, one category of electrification, efficient electric heat pumps for space and water heating, must realize increased adoption rates across New York State. Transitioning to electric heat pumps generally involves making significant upgrades to a building – including new heating equipment (*e.g.*, a cold-climate heat pump), and expanding and/or adding electrical boxes and wiring to power the heat pumps.

Q. Does the Company currently support customers to install efficient electric heat?

A. Yes. Con Edison offers incentives to customers for both cold climate air-source and ground-source heat pumps through the New York State Clean Heat program, a statewide program developed jointly by the Department of Public Service, the New York State Energy Research and Development Agency ("NYSERDA") and the state's electric utilities.

Q. Please explain the Clean Heat program.

A. The New York State Clean Heat program incentivizes contractors and customers to reduce the upfront cost to customers of installing cold-climate-certified air-source heat pumps (including mini splits), and ground-source heat pumps for space and water heating. The program also supports building envelope *(e.g.,* insulation, air sealing) upgrades to reduce the building space heating and cooling prior to heat pump installation. The State's electric utilities operate this program statewide using a common application and framework of program rules.

To qualify for incentives, contractors must design and install heat pump systems to meet criteria that include adequately sizing the heat pump system for the customers' needs. Incentives available through the Clean Heat program are based on the size of the heat pump itself (or, the energy savings it generates for large custom projects), and, in many buildings, are insufficient to overcome the barrier of the costs of customer-sided electrical upgrades needed to power the new heat pump equipment.

Q. Is the Company proposing a program, beyond the existing Clean Heat program, to support customers transitioning to electric heat pumps as their primary source of heating?

A. Yes. In addition to the Clean Heat program, the Company proposes to launch a Heating Electrification Make-Ready program to help offset the costs of behind-the-meter electrical upgrades required both to electrify space and/or water heating in buildings, and prepare these buildings' electrical systems for full electrification. By addressing this cost barrier, the program is intended to make electrification feasible for buildings that would be challenged to complete them otherwise.

Q. Has the Panel prepared an exhibit describing the Heating Electrification Make-Ready program?

A. Yes. A 7-page document entitled Heating Electrification Make-Ready Whitepaper, Exhibit___(CES-1), has been prepared under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-1)

Q. Please further explain the heating electrification Make-Ready Program.

A. As detailed in Table 5 below, this program will invest $76.6 million over three years to provide financial incentives and education, either through contractors or directly to customers, to upgrade building electrical equipment on the customer side of the meter as necessary for the increased use of electricity from space heating, water heating, and other appliance use. These proposed incentives reduce the costs of these electrical upgrades for customers and building owners. Eligible upgrades include new electric panels or sub-panels, wiring upgrades, and other necessary behind-the-meter electrical upgrades.

Table 5: Heating Electrification Make-Ready Costs

($000)

EOE*	2023	2024	2025
Contract Services	$2,130	$3,705	$5,655
Other (customer incentives)	$12,070	$20,995	$32,045
Total	$14,200	$24,700	$37,700

*Please see Exhibit 6 for the labor costs associated with this program.

Q. Why is this program needed?

A. To understand the need for this program, we explain the need by sector: a) Residential (1-4 family) homes and b) multi-family and commercial building sectors.

Q. First, why is this program needed for the 1-4 family home sector?

A. Based on interviews with electric heat pump installers and distributors, the Company estimates that 10% to 30% of existing 1-4 family homes lack capacity on their existing electric panel to connect electrified heating and other appliances. To install a heat pump, some customers need to replace their electric circuit breaker panel or add a sub-panel, adding approximately $700 to $2,500 to the project cost. Other customers may need an electric service upgrade. While the Company pays the costs of needed work on Company equipment to bring upgraded service to the meter, service upgrades can still result in customer behind-the-meter electrical work and costs (*e.g.,* new conduit and service entrance wires, and additional electrician labor hours to coordinate and complete the customer-sided requirements of the upgrade).

Currently, the Clean Heat Program does not address these costs. Without intervention, customers are likely either to find transitioning to electric heat pumps cost-prohibitive or will pursue a cheaper, limited electrical upgrade solution, generally a smaller sub-panel that may not allow for future electrification of other appliances or EV chargers. The proposed incentives will: 1) encourage more 1-4 family homeowners to pursue electrification today, and 2) support 1-4 family homeowners to make the upgrades necessary to support future full electrification of their homes most cost-effectively.

Q. And why is this program needed for the multifamily and commercial building sector?

A. In addition to the issues faced by 1-4 family homeowners, multifamily and commercial property owners face other issues. For example, electrical costs associated with heat pump installation can increase substantially due to building layout (*e.g.,* location of condenser units in relation to entry of electrical service), heat pump system design choices (*e.g.,* multiple distributed units vs. one central system), and existing building conditions (*e.g.,* condition of existing wiring). Costly electrical room upgrades may also be necessary, such as replacement and rewiring of the existing electrical panel.

Additionally, some building owners may choose to electrify their buildings in phases for a variety of reasons (*e.g.,* existing equipment lifecycles, tenant lease terms), potentially requiring panel work be repeated each phase. This approach is less efficient and, over time, more costly than addressing the building electrical needs upfront in a single comprehensive upgrade that “future proofs” the building.

This program will help offset these costs that can otherwise prevent heat pump projects from moving forward.

Q. How many buildings would this program support?

A. As noted in Exhibit __ (CES-1), the program would provide support to more than 3,000 existing multi-family and commercial buildings and 8,000 homes between 2023 and 2025, increasing adoption of clean heating technologies in these existing buildings.

Q. How does the Company plan to structure the incentives for this program?

A. The proposed incentives will depend on the customer segment and level of the clean heat upgrade. For those residential customers seeking space and/or water heating only, the customer would be eligible for up to $2,000 incentive for market-rate customers (or an estimated $2,500 incentive for LMI customers) to replace their home’s current electrical panel with a larger electrical panel. To be eligible for the incentive, the customer's new panel needs to add sufficient capacity to fully electrify the building, including capacity for both the current project (space and/or water heating electrification) and the future electrification of other appliances (*e.g.*, stove, clothes dryers).

Residential customers seeking to convert all fossil-fuel appliances to electricity (*e.g.,* stoves, clothes dryers) at once would be eligible for an additional incentive (incremental to the space/water heating incentive) of $1,000 for additional behind-the-meter electrical costs associated with providing power to these new appliances.

Multifamily and commercial and industrial property owners would be eligible for incentives covering up to 70% of total project cost. For LMI-qualifying multifamily buildings per existing NENY energy efficiency program definitions, building owners would be eligible for incentives covering up to 100% of total project cost. Eligible costs would include work related to the wiring of heat pump equipment (*e.g.,* condensers, air-handlers, water heaters), central electrical room upgrades, and any other customer work associated with upgraded service. Costs associated with preparing a building for future electrification of other appliances would also be eligible for incentives.

Q. What are the costs associated with the Heating Electrification Make-Ready program and how does the Company propose to collect these costs in rates?

A. Table 5 shows the projected costs of the program. As discussed, the Company proposes to treat these costs as a regulatory asset in the same manner as Clean Heat costs.

Q. What amortization period does the Company propose for the program costs?

A. The Company proposes to amortize costs over 15 years.

Q. Why is a 15-year amortization period appropriate for the Heating Electrification Make-Ready program?

A. The clean energy benefits resulting from the program will accrue over the useful life of the electrical upgrades and the operation of the supported heat pumps. This amortization period moderates customer bill impacts and aligns customer costs with the realization of customer benefits over time.

As discussed later, the Company proposes a Clean Heat amortization period of 15 years as well as the same amortization period for the Heating Electrification Make-Ready program.

Q. Does this program address all potential barriers associated with having buildings be “made ready” for electrification?

A. While this program addresses the cost barrier of customer behind the meter electrical upgrades, there are other barriers with making buildings ready for electrification that may warrant additional intervention and engagement. These include proactive upsizing of Con Edison equipment serving a building planning phased electrification, understanding when building electrification projects are likely to trigger building service upgrades (to be addressed through the Customer Recommendation and Analysis Tools below), or incenting building work needed for heat pump installations to be “made ready” for future efficient integration with clean district heat sources and/or sinks.

Q. In implementing this program, can the Company rely on program experience?

A. Yes. Con Edison's recent experience administering the Electric Vehicle Charging Make Ready program provides an opportunity to leverage lessons learned to inform program design and execution. Con Edison will also integrate the Heating Electrification Make-Ready program with the existing Clean Heat program to provide an integrated and streamlined customer experience.

B. Customer Recommendation and Analysis Tools

Q. Does the Company have a program to improve its customer experience?

A. Yes. The Company's Strategic Customer Experience ("Strategic CX") Portfolio will deliver a dynamic customer experience to meet evolving customer and stakeholder expectations as well as enable the Company to lead the transition to a clean energy future. While this portfolio is discussed in the Customer Operations Panel testimony, the Customer Recommendation and Analysis Tools are being developed in partnership with Customer Operations to assist the clean energy transition.

Q. What is the Customer Recommendation and Analysis Tools project?

A. The Customer Recommendation and Analysis Tools project ("Customer Tools") is a suite of tools to assist customers, especially mass-market customers, with the clean energy transition. The Company will transform its existing clean energy webpages and tools to provide customers with a personalized and interactive experience to engage in the clean energy transition. The Customer Tools will also support the contractors and other participants in the Company's clean energy programs who play a key role in facilitating customer adoption of clean energy technologies.

Q. What tools will the Customer Tools project provide to customers and contractors?

A. The Customer Tools will vary to reflect the differing needs and experiences of customers and others in this transition. The key focus areas include:

- **The Clean Energy Experience:** Through a digitized journey, the Company will provide customers with individualized energy savings and clean energy solution recommendations, cost estimates, bill impacts, eligible incentives, rate options, comparisons for mass market customers, and expected non-energy benefits. As the Company expands the portfolio of rate designs available to mass market customers, additional tools will help customers understand and compare available rate options.

Our long-term plan includes providing customers with a summary view of the Company’s clean energy programs that the customer was or is participating in, transparency into the customer’s clean energy project status and timeline for payment of program incentives, and status updates on any electrification-related upgrades required for Con Edison service.

- **Electrification Experience Hub:** The Company is investing in heating and transport electrification, building envelope upgrades, and addressing electrical constraints to encourage electrification. This digital tool will guide customers through the electrification process, including educating customers on the various technologies and potential benefits. The customer’s electrification experience will include service and system adequacy estimators.

- **Clean Energy Contractor Hub:** The Company’s contractor network requires digital tools with information about the Company’s clean energy programs, associated rules, project application requirements, and incentive amounts. Through this hub, eligible contractors will access Company-approved marketing materials, sales tools, and updates on their project status and program incentives.
- **Clean Energy Customer Service Tools:** To advise customers and recommend tailored clean energy solutions, Con Edison employees need additional tools. The project will explore additional Customer Service Representative (“CSR”) tools, business development management tools, and tools for the external vendors who manage the Company’s clean energy programs.

Q. Is the Customer Tools project an existing project?

A. No. To implement the Customer Tools, the Company needs to develop a roadmap detailing the plan to develop and implement these tools. The tools will be developed in phases through, among other processes, journey mapping for each customer segment, as well as through an iterative process to incorporate feedback and adjust to changing technologies. The Company intends to conduct and complete a Phase 0 assessment during 2022.

Q. Please explain the Phase 0 assessment.

A. The Phase 0 assessment includes, but is not limited to:

- Receiving input from key stakeholders, including Department of Public Service Staff, customers, customer advocacy groups, and contractors;
- Benchmarking available tools with other utilities, energy providers, and industries that provide similar customer tools;
- Identifying improvement opportunities in the Company's customer-facing clean energy webpages and tools;
- Assembling available external data sources and program offerings (*e.g.*, NYSERDA-led programs);
- Compiling integration requirements for linking to existing and planned Company systems (*e.g.*, DMTS, DRMS);
- Assessing external vendor products and/or analytic tools available for this project; and

- Identifying interactive tools to provide information needed for the customer's customized recommendations.

Following the Phase 0 analysis, the Company will develop an implementation plan.

Q. How will CES coordinate with Customer Operations on its Customer Tools project?

A. CES will partner with Customer Operations throughout project development and implementation, including surveys, interviews, and journey mapping with customers, contractors, and other key stakeholders.

Q. What are the forecasted costs associated with the Customer Tools project?

A. The forecasted capital costs for 2023 and 2024 are $12 million in each year, with $11 million for 2025 based on Table 6.

Table 6: Preliminary Customer Tools Project Capital Costs ($000)

	2022	2023	2024	2025
Labor	0	500	500	500
M&S	0	0	0	0
Contract Services	0	10,000	10,000	9,300

Other	0	1,300	1,300	1,000
Overheads	0	200	200	200
Total	0	12,000	12,000	11,000

The forecasted O&M costs are $5.5 million for 2023, $5 million for 2024, and $4 million for 2025. The non-labor expenses for this project include software-related fees charged by vendors. The labor expenses will fund additional full-time equivalent (“FTE”) resources to provide day-to-day management of the tools, manage the customer experience, and create and introduce new content.

Q. Has the panel prepared an exhibit describing the Customer Tools project?

A. Yes. A 7-page document entitled Customer Recommendation and Analysis Tools Whitepaper, Exhibit___(IT-5), has been prepared under our direction and supervision. Please note that this whitepaper is included in the exhibits in the Information Technology Panel as Exhibit __ (IT-5).

Q. Are there other tools that the Company is working on that will help customers and developers?

A. Yes. The Commission requires the development of an Integrated Energy Data Resource ("IEDR"). The Company supports this effort and is working with Staff, NYSERDA and other utilities to develop the IEDR. We have both assigned and hired personnel to assist with this effort.

Q. Is there a whitepaper or program change for the IEDR?

A. No. The Commission's Order addresses cost recovery for Phase 1 of the IEDR.

C. DER Make-Ready Program for Disadvantaged Communities and Low-Income Customers

Q. What is the DER Make-Ready Program for Disadvantaged Communities and Low-Income Customers ("DER Make-Ready Program")?

A. The DER Make-Ready Program offsets the customer costs of utility-sided upgrades needed to install DER to projects located in Disadvantaged Communities or that benefit low-income customers.

Q. Why is the DER Make-Ready Program needed?

A. Low-income customers and Disadvantaged Communities need additional support to transition to clean energy, and so far, there appears to be limited participation from this customer segment. For example, fewer than 20 percent of DER projects in the Con Edison service territory are located within Disadvantaged Communities as NYSERDA defines them. Moreover, just 0.5 percent of community distributed generation ("CDG") customers receive our low-income bill discount.

Q. Has the panel prepared an exhibit describing the DER Make Ready Program?

A. Yes. A 6-page document entitled DER Make-Ready for DAC and Low-Income Whitepaper, Exhibit __ (CES-2) has been prepared under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-2)

Q. Please provide an overview of the DER Make-Ready Program.

A. DER project developers incur utility interconnection costs when the DER installation requires utility upgrades (*e.g.*, new wiring, transformers, and relays) before approval to operate. The DER Make-Ready Program capital offsets DER developers' utility-sided interconnection costs for DER installations[11] located within a Disadvantaged Community or in a building where Company records show that at least 25 percent of the residents participate in the Company's Energy Affordability Program ("EAP"). DER Make-Ready Program support will be scaled to the capacity of the DER being developed and capped as listed in the table below.

Table 7: Capital Support Structure for the DER Make-Ready Program

Size	AC Nameplate Capacity	Maximum Capital Support
Small	51 kW – 499 kW	$150,000
Medium	500 kW – 999 kW	$300,000
Large	1 MW – 5 MW	$750,000

If a non-CDG project is both located within a Disadvantaged Community and provides benefits to low-income customers, the developer costs will only be offset once. This capital program support cannot be combined with the Community

[11] The Company proposes to exclude Community Distributed Generation projects from eligibility for this program as these projects are not likely to retain benefits of the clean energy project within the Disadvantaged Community.

Credit. The Electric Rate Panel discusses the tariff language related to this change.

Q. How would the DER Make-Ready Program interact with approaches proposed in the recent Staff Whitepaper "New York's 10 GW Distributed Solar Roadmap: Policy Options for Continued Growth in Distributed Solar"[12] ("Distributed Solar Roadmap")?

A. The Distributed Solar Roadmap proposes several up-front incentives for a variety of solar installations, including traditional Net Energy Metering, CDG, and non-CDG, but does not explicitly address interconnection costs. The DER Make-Ready Program addresses a barrier not covered by the Roadmap and should be considered complementary to the Roadmap's offerings.

Q. What is the projected cost for the DER Make-Ready program in this rate period?

[12] Case 21-E-0629 *In the Matter of the Advancement of Distributed Solar* (issued December 17, 2021).

A. The budget figures in Table 8 reflect the capital support we forecast needed to reach the MW targets shown in the table. (Note that Projected MW installed lags the capital support because the capital support is recorded as an up-front offset to project costs, and MW are recorded when the project becomes operational, which could be six to 18 months later due to construction timelines.)

Table 8: DER Make-Ready Program Costs
($000)

	2023	**2024**	**2025**	**Total**
Projected Awarded Capital Support	$5,900	$14,800	$5,000	$25,700
Projected MW Installed	7.2	21.6	43.2	72

The Company forecasts that that the annual O&M needed to administer the program will be $240,000, for internal and external resources to manage the program, including development of program documentation, conduct the intake, review, and approval of applications, and to support qualifying projects as they move through the interconnection process.

D. Clean Energy Credit for Low-Income Customers Program

Q. Please explain the Panel's proposed Clean Energy Credit for Low-Income Customers ("CEC-LI") program, and how would it contribute to an equitable transition to the State's clean energy future.

A. Through the proposed program, we will create a sustainable source of revenues to fund clean energy credits that will result in low-income customers sharing in the benefits of the clean energy transition. The revenue to fund the bill credit will be generated by the Company owning and operating transmission-connected solar generators. The Company will develop these solar generators within the State to provide additional economic development benefits. The Company will also develop these solar generators outside its and O&R's service territories to mitigate any potential vertical market concerns arising from ownership of these solar resources.

As described below, the Company will issue annual solicitations to purchase up to 1,000 MW of new solar generating projects over a ten-year period. The Company will use the revenues from these solar projects to provide electric bill credits to our low-income customers.

Q. Please describe how the program will work.

A. The Company will issue a competitive request for proposals annually for the ten years beginning in 2023 seeking to acquire 100 MW of solar project(s) each year. We expect these facilities to commence operations starting in 2024. The winning bidder(s) will be contractually responsible for designing, permitting, constructing, interconnecting, and commissioning an operating solar facility. They would then transfer the facility to Con Edison on the commercial operation date.

The investment in each solar project will be treated as utility plant and included in rate base. The Company will sell the available energy from its plants into the market through the New York Independent System Operator (“NYISO”). The Company will receive market revenues from the project from energy and capacity sales. The Company will also record the prevailing market value of Renewable Energy Credits ("RECs")[13] as project revenue.[14] Any net revenues from the generating assets (*i.e.*, NYISO market revenues plus the prevailing market value of the RECs[15] minus solar facility O&M costs) will fund an additional electric bill credit for low-income customers enrolled in the Company's low-income affordability program.

Q. How will low-income customers benefit from this program?

A. The Company forecasts that revenues after operating expenses from each 100 MW of renewables will fund approximately $7

[13] A Renewable Energy Credit (REC) represents 1 MWh of electricity generated by a qualifying renewable energy project in New York. Each Load Serving Entity (including Energy Service Companies (ESCOs) and utilities) must purchase a quantity of RECs equivalent to a certain percentage of the total energy used by their customers in each year, as specified through the Commission's Clean Energy Standard. *See,* Case 15-E-0302, *Proceeding on Motion of the Commission to Implement a Large-Scale Renewable Program and a Clean Energy Standard*.

[14] The Company would use the RECs the project generates to offset its obligation to procure RECs on behalf of its full-service customers.

[15] The prevailing market value of the RECs will be set at the REC price established by NYSERDA's most recent solicitation for Large Scale Renewable projects. *See*, *e.g.*, https://www.nyserda.ny.gov/All-Programs/Clean-Energy-Standard/Renewable-Generators-and-Developers/RES-Tier-One-Eligibility/Solicitations-for-Long-term-Contracts/2020-Solicitation-Resources

million a year in low-income credits. This means each 100 MW of in-service solar generation would provide an incremental credit of about $15 per customer per year, once operational. The Company forecasts that when fully implemented over 10 years, the 1,000 MW of solar projects will enable it to reduce bills for each recipient by an average of $17 per month (roughly $200 per year), or an approximately 14% reduction in the average electric bill for our low-income customers.

Q. Did the Company consider the Commission’s concerns about utility ownership of generation?

A. Yes. First, as noted above, the Company plans to seek projects located outside of the Con Edison and O&R service territories. This should alleviate any concerns about vertical market power because the assets would not be impacted by operational decisions on Con Edison or O&R transmission and distribution systems. Furthermore, because they do not have variable operating costs, the Company would bid the solar generation as a price taker and would not be able to artificially impact wholesale market prices.

Moreover, the Commission has acknowledged the role for utility investment to address particular areas, such as meeting low-income customer needs where there is no developed market and the public interest warrants utility investment to support development.[16] Thus, the Commission can approve utility ownership where there is a public benefit, such as the advancement of the State's renewable energy goals and the support for energy affordability.[17]

Q. Why is this proposal better than having third parties own and operate solar facilities?

A. The Company's proposal has two significant benefits that would not necessarily be replicable without utility ownership of the asset. The first benefit is that as a regulated entity, we can stream all net market revenues to our low-income customers to provide them incremental bill

[16] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p. 49.

[17] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016), p. 54.

credits. The second benefit has to do with the residual value of the project. When it owns the asset, the Company can continue to operate the asset for customer benefits for the life of the asset and potentially longer, if repowered. With this residual value, our customers will potentially pay less than the cost of obtaining the renewable power from a third party for the full life of the asset.

Q. Please describe the funding requirements of this program during the rate years, as well as the proposed ratemaking treatment for this program.

A. The estimated incremental costs are for purchasing and owning the proposed 200 MW of solar resources that would become operational by 2025. We forecast $100 million in each of 2024-2025 to fund these plants.

Upon commercial operation, the Company will include its payment to purchase the solar resources in rate base. Energy, capacity, and REC revenues will offset the O&M costs associated with these renewable resources.

Q. Can the Company use tax benefits available to other developers to reduce the cost of these projects?

A. The Company will attempt to avail itself of any applicable tax benefits.

Q. Is the Company’s proposal compatible with New York’s 10 GW Distributed Solar Roadmap (“Roadmap”) issued by Staff and NYSERDA on December 17, 2021?

A. Yes. By targeting larger transmission scale projects and streaming the net benefits of operating those projects to all our low-income customers, the Company’s proposal fills a need not covered by the Roadmap. The Roadmap proposes meaningful incentives to encourage both direct adoption of solar by low-income customers and customers participating in CDG projects, but does not provide incentives for the larger solar systems the Company would acquire under its CEC-LI program. Similarly, while the Roadmap targets 150 MW of rooftop installation and 300 MW CDG, with a target of 40 percent participation from low-income customers, most low-income customers are not able to directly install rooftop at their premises. Moreover, low-income customers subscribing in a CDG project would only be expected to receive a 10% discount on their solar allocation. Therefore, the Company’s proposal, which will provide all low-income customers with a larger, more meaningful electric bill credit, complements the Roadmap.

Q. Has the panel prepared an exhibit describing the CEC-LI program?

A. Yes. An 8-page document entitled Clean Energy Credits for Low-Income Customers Whitepaper, Exhibit __ (CES-3), has been prepared under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-3)

E. Distributed System Platform

Q. What is the Distributed System Platform (DSP)?

A. The Company’s DSP is the platform of tools, technology, infrastructure, and services that the Company is implementing to more fully integrate DER into electric distribution system planning and operations. DSPs are comprised of the people, processes, and systems that allow utilities to provide three core, interrelated services: (1) facilitating expanded DER integration; (2) sharing information that helps third parties identify business opportunities and maximize the value of their investments;

and (3) expanding market services. The evolution of the Company’s DSP since 2016 is documented in its bi-annual filings of its Distributed System Implementation Plan, most recently filed in June 2020.[18]

Beginning with project development and interconnection, our proposed DSP improvements will allow DER developers greater insights into customer and system needs – coupled with new interconnection options that enable larger DER installations at lower overall interconnection costs. The DSP will enable a more dynamic operation of the distribution system, with DER seamlessly responding to dispatch, operational control, or price signals for real and/or reactive needs.

Q. How does the Company plan to build upon its DSP in 2023-2025?

A. The Company proposes to invest in DSP tools and technologies, including:

[18] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans,* 2020 CECONY DSIP (filed June 30, 2020).

- **Customer- & Developer-Facing Tools:** Interconnection Online Application Portal ("IOAP"), Hosting Capacity and Coordinated Electric System Interconnection Review ("CESIR") process.
- **Operational & Program Tools:** Demand Response Management System ("DRMS"), and Demand Management Tracking System ("DMTS").
- **DER Infrastructure:** Smart Inverter, Connect DER, Protective Relay, and Conservation Voltage Optimization ("CVO").
- **Advancing DSP Innovation:** DER Integration and Management program proposal, which includes a Grid Edge Test Laboratory and operational and information management software tools.

Together, these four investments will further advance the integration of DER into the electric distribution system, enabling customers and developers benefit from DER.

Q. What are the costs associated with these DSP investments?

A. Costs associated with DSP investments are shown in Table 9 below.

Table 9: DSP & DER Integration and Management Program Capital Budget

	2023	2024	2025
DSP			
IOAP	$600	$600	$600
DMTS	$5,000	$5,500	$6,000
DRMS	$9,960	$9,900	$9,900
Modernizing Protective Relays	$30,600	$30,600	$30,600
CVO	$15,000	$15,000	$15,000
Additional Projects:			
Connect DER	$1,000	$1,000	$1,000
Budget	**$62,160**	**$62,600**	**$63,100**
DER Integration and Management Program			
Information Systems & Operational Software	$15,484	$13,000	$13,000
Grid Edge Laboratory	$1,000	$2,250	$2,250
Total Budget	**$16,485**	**$15,250**	**$15,250**

There are also ongoing O&M costs associated with implementing and maintaining these initiatives. The forecasted costs are $7.0 million for RY1, $6.9 million for RY2, and $6.1 million for RY3. These expenses include licensing fees associated with new third-party software and expanded use of existing software and increased resourcing to enable integration of various software platforms.

Table 10: DSP & DER Integration and Management Program O&M Budget

	2023	2024	2025
DSP			
IOAP	$400	$400	$400
DMTS	$1,200	$1,200	$1,200
DRMS	$600	$600	$600
Modernizing Protective Relays			
CVO	$1,300	$1,100	$300
Additional Projects:			
Connect DER			
Total Budget	**$3,500**	**$3,300**	**$2,500**
DER Integration and Management Program			
Information Systems & Operational Software	$3,500	$3,570	$3,641
Grid Edge Laboratory			
Total Budget	**$3,500**	**$3,570**	**$3,641**

Table 11: Regulatory Asset Expenditures

	2023	2024	2025
DER Integration and Management Program			
Smart Inverters	$3,000	$10,000	$12,000

Q. Has the panel prepared any exhibits describing its proposed investments in the DSP that are included in the Information Technology Panel exhibits?

A. Yes. Two documents have been prepared under our direction and supervision, one, a 10-page document entitled REV-Grid Modernization (Distributed System Platform) Whitepaper, and the second, a 13-page document entitled DER Integration and Management Program Whitepaper, have been included in Exhibit ___ (IT-5), part of the Information Technology Panel testimony.

Q. Please describe the State's policies and how they affect the Company's proposals for continued DSP investment?

A. The State's clean energy policy[19] provides that the State will have 6 GW of solar by 2025 and 6 GW of energy storage, and achieve 70% renewable energy by 2030. Combined with existing goals (200,000 EV chargers by 2030) and New York City targets (500 MW of storage in NYC by 2025, and 1 GW of

[19] S6599 Climate Leadership and Community Protection Act of 2019; Governor Hochul's New York State of the State Address, 2022.

distributed solar in NYC by 2030), the Company anticipates that distributed solar may nearly double in size and storage capacity may grow exponentially by 2030 in its service territory. Through its proposed DSP investments, the Company will facilitate installation, operation, and integration of these resources.

i. Customer- and Developer-Facing Tools

Q. Please describe investments that the Company proposes to make in Customer- and Developer-Facing Tools.

A. The Company proposes two main projects – updating the DER hosting capacity maps and improving the DER interconnection process. For example, we will enhance hosting capacity information with a building-level tool that provides interconnection cost estimate ranges, aligning them with the CESIR study. This will improve the ability of market participants to make informed decisions regarding the location and potential value of new DER resources.

For DER interconnection, we propose to enhance the application process (using the IOAP) and increase automation within the CESIR study process. Currently, data processing components of the CESIR study process are manual and may vary based on interconnection demands on the system.

Finally, the Company proposes to enhance its ability to validate DER data. Currently, Con Edison cannot validate customer asset information between the time of interconnection and market registration, creating a potential misalignment of information between the two steps.

ii. Operational & Program Tools

Q. Turning to Operational and Program tools, please provide some examples of the Company's proposed enhancements.

A. For RY1-RY3, we plan to implement enhanced Customer Relationship Management capabilities within the DMTS to expand customer participation and improve opportunities for energy savings and demand reduction across existing and future programs. The system upgrades include integrating new program offerings, expanding incentive estimation tools, and decreasing the time from application submission to project payment.

We will also make investments in our DRMS, which manages enrollment, event initiation, performance monitoring, and settlement of the Company’s DR programs. These enhancements include expanded enrollment capabilities as more residential and small commercial customers participate in aggregator enrollments.

iii. DER Infrastructure

Q. What is meant by DER Infrastructure?

A. DER Infrastructure refers to the Company’s physical equipment that supports the integration into and efficient operation of DER on our electricity system.

Q. Please explain the programs the Company is proposing in this category.

A. The Company proposes a Smart Inverter customer program, continued investments in the Connect DER device used to wire DER into a site’s electric meter, continued investments in modernizing network protectors, and improving CVO energy savings through additional projects.

Q. What is a smart inverter?

A. An inverter is a device that converts power generated by a clean energy installation from Direct Current to usable Alternating Current so that it can be used by customers within their home or business. A smart inverter allows the remote monitoring and control of the power generated by the clean energy installation.

Q. Does the Company propose any programs to address smart inverters?

A. Yes. The Smart Inverter customer program will spur adoption of the latest clean energy technologies by providing customer incentives to purchase these devices for their solar installations. Additionally, this program will enable programming of smart inverters' reactive volt-VAR support settings, and other grid support features creating potential to call upon these resources to decongest and add capacity to the system.

Q. Please explain Connect DER.

A. The Connect DER device allows for lower cost integration of solar power into a premises' electrical system. The Company proposes to install these devices at 2,400 customer locations to enhance remote monitoring and control of the associated DER. The program is part of NYSERDA's Future Grid Challenge.[20]

Q. Please describe the Company's proposed investments in modernizing Network Protectors.

A. The Company will continue its existing program to modernize Network Protectors ("NWP") through upgrading relays and installing Supervisory Control and Data Acquisition ("SCADA") capability. This grid modernization effort, which begun in 2017, not only provides NWP with the intelligence to distinguish DG back-feed from fault current through an upgraded protective relay, but also permits remote control and two-way power flow. Upgraded NWPs are required for the system to accommodate clean DER that exports onto the system. This program covers the cost of upgrading relays and

[20] "Winning Teams Under First Two Rounds of 'Future Grid Challenge' Will Improve Efficiency and Reliability in Renewable Energy Integration," NYSERDA press release (Issued March 26, 2020). *See*, https://www.nyserda.ny.gov/About/Newsroom/2020-Announcements/2020-03-26-NYSERDA-ANNOUNCES-WINNERS-OF-CLEAN-ENERGY-CHALLENGE-TO-MODERNIZE-NEW-YORKS-ELECTRIC-GRID

installing SCADA, where necessary, within NWPs so that clean DER developers do not incur these costs.

To date, the Company has upgraded 3,829 NWP (and equipped 1,336 of these with SCADA capability) out of approximately 27,000 NWP in the secondary grid. The Company plans to continue this program to address each location that is or becomes DG constrained, as well as all locations with persistent back-feed issues.

Q. What is Conservation Voltage Optimization (“CVO”)?

A. The CVO program uses the Company’s AMI meters to precisely measure the voltage being delivered across the system and more closely align power flows to maintain acceptable voltage along the distribution feeder. The CVO program measures the complete voltage profile of a network area and optimizes the operation of voltage regulation equipment according to the measured voltage at the edge of the grid. Using optimal voltages reduces total energy consumption and associated power generation emissions, resulting in both customer energy savings and a reduced carbon footprint.

Q. Has the Company been implementing CVO in conjunction with its AMI program?

A. Yes. Con Edison has been implementing CVO incrementally throughout the ongoing AMI meter deployment efforts. Currently, 80 networks use CVO to optimize voltage. The remaining two networks will optimize voltage during 2022. Using this information, the Company has proactively changed the voltage schedule to optimize CVO.

Q. As a result of the AMI program, does the Company have CVO goals?

A. Yes. The Company's AMI business case projected 1.50 percent CVO energy savings. As of December 2021, we achieved 1.21 CVO energy savings and we expect to meet the 1.50 percent CVO energy savings goals.

Q. Does the Company want to increase the level of CVO energy savings?

A. Yes. During 2023-2025, the Company proposes to undertake two projects to increase the CVO energy savings to 1.75 percent by 2025.

Q. Please describe the Company’s proposed continuation of the CVO program.

A. To increase CVO energy savings during the upcoming period, we will make the following two investments. First, to address secondary system areas where there may be low voltage, we need to reinforce the secondary system. That is, we will upgrade and reconductor our secondary system to allow the Company to adjust the voltage, while meeting voltage range requirements. Second, we will adjust transformers in area substations to allow settings to be changed for voltage optimization, an O&M cost. This work requires the transformer to be removed from service to work on the internal equipment.

Q. Will these two projects increase the amount of savings associated with CVO?

A. These efforts are expected to produce net energy savings that will reduce the supply-side costs of the customer bill, while further reducing GHG emissions.

iv. Advancing DSP Innovation

Q. What is meant by Grid Edge?

A. Grid edge is the point where utility infrastructure ends, and the customer connects to the utility. Presently, our customers draw power from and export power to the grid. In the future, we see a substantial scaling of this functionality requiring study and testing to confirm that the grid can handle these flows.

Q. What is a grid edge laboratory?

A. A grid-edge laboratory is a physical and virtual space where new and conceptual energy technologies, including software, can be developed and subsequently tested for potential deployment without any effect on operations. Mirror versions of operating software are created within the laboratory.

Q. Please describe the Company's proposal related to the grid edge technology laboratory.

A. The Company proposes to build a grid edge technology laboratory that will collaborate with: (1) local community advocate organizations; (2) clean energy technology vendors; and (3) other utilities with large urban systems.

In the short term, this laboratory will allow Con Edison to develop new tools and train employees in a simulated environment. In the longer term, this laboratory will be leveraged to develop the next horizon of operational capabilities, for New York's unique grid topology.

Q. Please continue.

A. As part of these investments, the Company proposes to improve the hosting and registration process by developing search and find capabilities that will enable customers to select favorable DER sites on its hosting capacity maps. Second, the Company will expand its ability to monitor and control DER status and integrate this information into its system operations. Third, the Company will develop software tools to facilitate the smart inverter program discussed above.

Q. Are additional investments in information systems and operational technology needed to enable these new tools?

A. Yes. The capabilities described above all require incremental IT/OT investments including: (1) a new database that captures key characteristics of each interconnected DER that can be connected to other Company systems; (2) a system that will collect data from DER in real-time and translate that data so that other Company systems can use it; (3) a custom network load flow modeling solution that can integrate DER and weather data; (4) a non-network load flow modeling solution to perform the functions of item 3 in non-network areas of the system; (5) a link between items 2, 3, and 4 to assess whether newly proposed DER projects can be accommodated by the system; and (6) cybersecurity system improvements so that items 1-5 can be safely and securely integrated into the Company's system operations tools.

F. Innovative Pricing Pilot

Q. Please describe the Innovative Pricing Pilot Expansion initiative.

A. Con Edison launched the Innovative Pricing Pilot ("IPP") as part of the Company's AMI Customer Engagement Plan. Since 2019, the Company has deployed a portfolio of mass market, time-variant, demand-based rates to customers in Staten Island, Westchester, and Brooklyn. Through the IPP's first three waves, the Company has observed positive results regarding customer retention, bill savings, and load impacts. However, due to the impacts of COVID-19, much of the pilot data – though valid – is impacted by unprecedented changes in how customers use electricity. For this reason, the Company has proposed a fourth wave of the IPP to obtain additional data. Additionally, due to the forthcoming completion of Con Edison's AMI rollout, the pilot continuation allows for customer participation in new boroughs to provide additional insights.

Q. Please describe the proposal the Company has made to the Commission for this IPP expansion plan.

A. Ordering Clause 7 the Commission's December 13, 2018 Order in Case 18-E-0397[21] required the Company to file a detailed report analyzing the results of the IPP. The Company made that filing on November 24, 2021[22] ("November 2021 Filing")

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[21] Case 18-E-0397 *Tariff filing by Consolidated Edison Company of New York, Inc. to Make Revisions to its Electric Tariff Schedule, P.S.C. No. 10, to Add New Riders Z (Residential) and AA (Small Commercial) Innovative Pricing Pilot, to Implement Rate Structures for Residential and Small Commercial Customers*, Order Approving Tariff Amendments with Modifications (issued December 18, 2018) p.25.

[22] Case 18-E-0397, *Tariff filing by Consolidated Edison Company of New York, Inc. to Make Revisions to its Electric Tariff Schedule, P.S.C No. 10, to Add New Riders Z (Residential) and AA (Small Commercial) Innovative Pricing*

and included a proposal to expand the IPP, adding a fourth wave, that it would conduct between October 2022 and May 2025. Details of the IPP expansion plan are included in Appendix C to the November 2021 Filing.

Q. What are the costs associated with this initiative during the rate year and subsequent years?

A. As detailed in Appendix C of the November 2021 Filing, estimated O&M costs are $5.4 million for 2023, $5.3 million for 2024, and $4.4 million for 2025. There are no capital costs associated with this effort.

Q. Is the Company seeking Commission approval of the IPP expansion plan and funding levels in this proceeding?

A. No. The Company is seeking Commission approval of the IPP expansion plan and funding levels in the pending November 2021 Filing. As discussed further below, in this proceeding, we are seeking to include those funding levels in the

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Pilot, to Implement Rate Structures for Residential and Small Commercial Customers, Con Edison Innovative Pricing Pilot Report (filed November 24, 2021).

Company's base rates because that is the Commission's preferred place for collecting these costs.

Q. How does the Company propose to recover the costs associated with the IPP expansion?

A. Consistent with previous recovery of IPP costs, the funding for November 2021 IPP expansion plan is included in the rate year revenue increase requested in this proceeding. If the Company enters into a multi-year rate plan, the Company proposes to continue to recover the IPP expansion costs in subsequent rate years.

If, in acting on the November 2021 Filing, the Commission alters the level of funding for the IPP expansion plan, a corresponding adjustment can be made to the revenue requirement in this proceeding.

Q. Has the Panel developed an exhibit to further explain the next phase of the IPP program?

A. Yes. The 6-page whitepaper entitled Innovative Pricing Pilot Expansion Whitepaper, Exhibit___(CES-4) was developed under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-4)

V. Clean Energy Infrastructure

A. Energy Storage

Q. Please summarize Con Edison's proposals to advance the use and effectiveness of energy storage within its service territory.

A. First, we note that the Company is making these proposals to help achieve the State's clean energy goal of 6,000 MW of energy storage by 2030. We estimate that approximately 3,000 MW of the energy storage will be located in our service territory. Energy storage is crucial to achieving the clean energy transition downstate, as the State implements its policy of retiring in-City peaking generation and replacing them with offshore wind facilities. As such, Con Edison is taking steps to achieve this vision.

First, the Company proposes to create an energy storage group to develop new products and delivery channels to facilitate the installation, interconnection, and operation of energy storage. This group, which requires additional staffing, will expand the Company's energy storage knowledge base and help deploy energy storage installations in the utility's service territory.

Second, the Company proposes four new energy storage installations, intended to test and demonstrate the ability of storage to meet specific system needs and support public policy objectives.

Q. What energy storage projects are currently underway?

A. We have several projects underway. In compliance with the 300 MW bulk storage requirement in Con Edison's service territory, the Company conducted an initial RFP and awarded a contract for a 100 MW facility to be built at the site of the former Poletti power plant in Astoria. The Company has issued a second RFP for bulk storage on its system – responses are currently under evaluation and awards are expected to be made during 2022.

Additionally, the Company is installing a 7.5 MW / 30 MWh lithium-ion storage system at our Fox Hills substation in Staten Island. Through this process, the Company is developing internal expertise in designing and constructing the project. These insights allow us to refine our processes and work with developers seeking to install storage in our service territory.

Q. Has the Panel prepared an exhibit discussing these projects and other Utility of the Future changes?

A. Yes, a 21-page exhibit entitled Energy Storage and Utility of the Future Whitepapers, Exhibit __ (CES-5) was prepared under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-5)

Q. Please describe the Company’s proposal for the formation of an energy storage group.

A. The Company proposes to create an energy storage group to facilitate the installation, interconnection, and operation of energy storage in its service territory. The overall request is to add sixteen employees to assist with energy storage, ten of which will assist with facilitating external energy storage projects and six will assist with internal projects. The Company will stage its hiring, as described in the whitepaper, and plans to have all these employees in place by 2025.

Q. Please explain why the ten incremental employees in the energy storage group are needed to support the growth of energy storage in the Company’s service territory.

A. Collectively, the ten energy storage professionals will develop new opportunities for energy storage; streamline processes to evaluate and implement RFPs; identify and prioritize interconnection locations for energy storage; and reduce soft costs for storage projects as they navigate the permitting process. The group will also provide daily oversight of the current and future energy storage asset portfolio to keep assets operational and operate these facilities to support real-time grid functions and system contingencies. The energy storage market has untapped potential, and we need both people and processes to help optimize the value our customers get from these investments.

Q. What specific roles will the other six FTEs in the utility energy storage project group perform?

A. Four FTEs will manage the proposed utility-owned storage projects described below. The remaining two FTEs will operate and coordinate maintenance of these new projects as they come online.

Q. What are the costs associated with this proposal?

A. The total headcount estimates associated with the proposed additional employees for both the energy storage market development and implementation and energy storage installation and operation groups are shown in Table 12 below.

Table 12: Energy Storage Labor Costs

	2023	2024	2025
Energy Storage Market Development & Implementation			
Incremental Headcount	6	9	10
Incremental Budget $(000)	$815	$1,287	$1,460
Energy Storage Installation & Operation			
Incremental Headcount	4	5	6
Incremental Budget $(000)	*Included in project costs (see Table 13 below)*		

Q. Turning to energy storage installation and operation, please discuss the Company’s proposal.

A. As a next step for storage, the Company proposes to construct four additional utility-owned storage installations in our service territory to support the local distribution system and to explore new designs and methods to interconnect multiple DER with storage. These four projects will enable the Company to broaden its expertise in future storage deployments and share lessons learned with the energy storage industry. The four storage initiatives involve the: (1) Grassland Substation in Valhalla; (2) Glendale Substation in the Maspeth Network; (3) Cedar Street Substation in New Rochelle; and (4) Freshkills Substation in the Freshkills Network. If approved, each of the projects is expected to be operational before the end of 2025.

Q. Please describe the location, operating mode and expected lessons learned from the first project.

A. For the Grassland project, the Company will install a 11.6 MW / 46.4 MWh energy storage system at the Grassland Substation in Valhalla designed to integrate with nearby solar energy to offset its charging needs. In collaboration with the County of Westchester, the Company will also install at least 200 kW of solar panels on adjacent vacant land. The energy storage system will help to accommodate the high penetration of solar generation in the area and the associated evening load ramp as the sun begins to set. This project will provide important insights regarding balancing energy storage with solar generation to optimize network hosting capacity. We expect to gain firsthand experience in optimizing the dispatch of an energy storage facility to simultaneously support and optimize solar generation, manage increasing load on a local network, including contingency support, and maximize market revenues. This will allow us to be better informed on customer design and provide guidance for third party DER.

Q. Please explain the second project.

A. The second project will install a 5.8 MW / 23.2 MWh energy storage system at our Glendale Substation. The asset will support a planned 60 MW load transfer into the Glendale substation and relieve the sub-transmission feeder. Through this project, we expect to learn how the combination of utility-sited storage and third-party energy storage systems can complement one another in providing needed load relief.

Q. Please discuss the third proposed project.

A. In the third project, the Company will install an innovative, first-of-its-kind in North America DC-bus system to pair DER, potentially changing interconnection methods. To enable this, the Company would install a 5 MW / 20 MWh energy storage system at a substation in New Rochelle. This project will pilot the use of a common DC bus between the energy storage system, a third-party owned and operated PV canopy, and third-party owned and operated EV chargers. Because this project pairs EV charging with solar and storage, it will enable charging of EVs along the I-95 corridor during power outages. The Cedar Street project will also provide operational flexibility and resilience during contingencies and high load days.

Q. Please explain the final project.

A. The Freshkills Substation project involves the installation of an 11.6 MW / 46.4 MWh energy storage system. This project will provide peak demand reduction and Volt / VAR support to help address growth of both distributed solar energy and overall energy use in the Freshkills Network in Staten Island.

Q. What are the benefits of these projects?

A. The projects address cutting edge power quality challenges that are not efficiently addressed by traditional equipment, such as balancing the composition of VARs on the distribution network. Certain electronic equipment (*e.g.*, those without a motor), including EV chargers and inductive cooktops, are creating new power quality dynamics on the system because of how they use electricity. Energy storage systems have the potential to improve power quality management. These projects will increase operational flexibility through new controls for grid operations at the substation and in the local distribution network / load area.

Each project will also help develop new pathways for future energy storage development. Implementing these projects will help the Company develop key energy storage and DER integration competencies around development, engineering and design, procurement, construction, operation, and maintenance of storage assets.

Q. Why is utility ownership of these storage assets necessary to achieving the benefits discussed above?

A. Utility-owned storage allows learnings that cannot be addressed by the market. Notably, utility-owned project development provides hands on experience to develop innovation insights that we will share with the market more broadly.

First, we are working with New York City agencies to streamline permitting processes and set industry standards, improving timelines for energy storage. Any streamlining achieved will benefit all developers.

Second, we are working with the NYISO to establish energy storage dispatch functionalities. This includes establishing communication between the storage asset and NYISO, testing of the energy storage response to NYISO dispatch signals, and establishing requirements. This work will assist in developing energy storage resources in the market, including for example, testing the operational coordination efforts required for FERC Order 2222 implementation. Any NYISO lessons learned can be shared with developers in NYISO stakeholder meetings.

Last, we are developing cutting edge energy storage designs that can change the way interconnection is done for Community DG and microgrids. The Cedar Street project will use a common DC bus to reduce the number of DC-AC conversions and equipment costs associated with DER deployment. We will use these learnings to update our interconnection standards for community DG and microgrid deployments and share our findings with stakeholders.

Q. What does the Company propose to do with the revenues from its ownership of storage?

A. The Company proposes that the net market revenues from these four storage projects participating in the NYISO’s wholesale markets be used to augment the electric credits offered to low-income customers. Because these projects are small, the Company estimates that these revenues could provide low-income customers with a small amount of additional savings, between 0.37% ($0.4) and 1.10% ($1.22) of their monthly bill between 2023 and 2025.

Q. What are the expected costs of the projects?

A. Table 13 summarizes the estimated costs of the energy storage projects through 2025.

Table 13: Energy Storage Installation and Operation Request by Year ($000)

	2023	**2024**	**2025**
Capital	37,701	41,702	41,702
O&M	2,232	2,316	6,446

Capital costs reflect Company engineering and construction estimates informed by vendor quotes from the Fox Hills project. O&M costs reflect execution-related expenses, including site remediation, and ongoing O&M expenses, including warranty and maintenance expenses. Costs associated with O&M for existing energy storage projects are also included in the forecast.

B. Demand Management

Q. What is covered in this section?

A. This section discusses the Company’s Demand Management program, comprised of Non-Wires Solutions, Non-Pipeline

Alternatives, and Demand Response, including their combined labor request.

i. Non-Wires Solutions

Q. What is an NWS?

A. An NWS is a cost-effective portfolio of non-traditional, typically customer-side solutions, that enable the elimination or deferral of a traditional asset that would be required to meet a reliability need.[23] The Company implements NWS in identified areas of locational need to defer or eliminate traditional infrastructure solutions. We develop NWS portfolios that are generally comprised of different DER solutions. In addition to deferring or eliminating the traditional solution, benefits include decreased energy and capacity costs from the wholesale market, reductions in GHG emissions, marginal cost reductions to upstream transmission and distribution

[23] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans,* 2020 CECONY DSIP (filed June 30, 2020).

equipment as well as others described in the Benefit Cost Analysis Handbook ("BCAH").[24]

Q. Is the Company implementing NWS projects?

A. Yes. For example, in addition to the 41 MW of customer-sited solutions originally sought under the Brooklyn Queens Demand Management program ("BQDM"), the Company is implementing an NWS project targeting 21 MW of required load relief to defer traditional infrastructure upgrades in the Newtown area through 2024. The Company is continually evaluating suitable traditional projects for additional NWS opportunities.

Q. Are there any NWS projects being evaluated for implementation during the three rate years?

A. Yes. In addition to the Company's active NWS portfolio, Con Edison has identified two potential NWS opportunities related to the: 1) Jamaica Substation - Replace Limiting 27kV Bus Sections Project; and 2) the Parkview TR5 and Feeder 38M85 Project.

[24] Case 16-M-0411, *In the Matter of Distributed System Implementation Plans*, Con Edison Electric BCA Handbook v3.0 (filed July 31, 2020).

Q. Is there an existing ratemaking or incentive mechanism associated with NWS?

A. Yes. Costs associated with NWS projects are included in the revenue requirement and amortized over 10 years.[25] Upon project completion, the Company also earns a shareholder incentive equivalent to 30 percent of the NWS portfolios net benefits as calculated using a Benefit Cost Analysis.[26]

Q. Is the Company proposing any changes to the ratemaking or incentive mechanisms associated with NWS?

A. No. The Company plans to retain the existing NWS framework and continue the current incentive mechanism.

ii. Non-pipeline Alternatives ("NPA")

Q. Please briefly describe an NPA and the benefits it provides.

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[25] Case 15-E-0229, *Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs that Support Reforming the Energy Vision*, Order Implementing with Modification the Targeted Demand Management Program, Cost Recovery, and Incentives (Issued December 17, 2015).

[26] Case 15-E-0229, *Petition of Consolidated Edison Company of New York, Inc. for Implementation of Projects and Programs that Support Reforming the Energy Vision*, Order Approving Shareholder Incentives (Issued January 25, 2017).

A. Similar to an NWS on the electric system, an NPA is a portfolio of customer-sided solutions that defers or eliminates the need for traditional gas infrastructure. To the extent that an NPA defers or replaces traditional infrastructure with lower-cost alternatives, it can lower gas system infrastructure costs. NPAs are consistent with State energy policy as expressed in the CLCPA and the Climate Action Council's Draft Scoping Plan's emphasis on decarbonizing the State's building stock and vision for "downsizing"[27] the gas system. In addition, the Company's current rate plan required that the Company develop a framework for NPAs, which was filed in September 2020.

Q. Is the Company currently implementing any NPA projects?

A. The Company has been pursuing NPA projects in line with Commission policy under its current rate plan and expects to move its first NPAs to implementation during 2022. Most recently, in December 2021, the Company filed a Targeted NPA

[27] Climate Action Council. "New York State Climate Action Council Draft Scoping Plan" December 30, 2021. Accessed January 11, 2022. *See*, https://climate.ny.gov/Our-Climate-Act/Draft-Scoping-Plan

Petition[28] seeking Commission approval to use a specific amortization period and incentive structure to proceed with four NPA projects: Main Replacement Program, Soundview in the Bronx, Port Chester in Westchester, and Bayside in Queens. The Company solicited an Implementation Contractor for the Main Replacement Program NPA in July 2021 and expects to be able to move to contracting with its selected vendor in early 2022. The Company also released an RFP for Soundview and Port Chester, with responses due in March and April 2022, respectively.

Q. How does the Company identify NPA opportunities?

A. The Company has taken initial steps to integrate NPA into its Gas planning process. The Company's planning processes assess the system's current and expected future operating conditions relative to the Company's design standards and methodology, considering forecasted changes in localized

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[28] Case 19-G-0066, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service*, Petition of Consolidated Edison Company of New York, Inc. for Approval of Specific Non-Pipeline Alternative Projects, ("Targeted NPA Petition") (Filed December 22, 2021).

peak day demand. The Gas Infrastructure, Operation and Supply Panel ("GIOSP") describes the Gas Distribution Forecasting Model to facilitate localized system planning and NPAs. Through this process, system engineers identify system needs and develop various options for addressing those needs. These options are then assessed for: (1) effectiveness in meeting the need; (2) cost; (3) implementation timing; and (4) risks. Solutions are prioritized by balancing available capital and resources against the risk of not addressing the system need within the timeframe of the capital plan.

Q. How does the Company evaluate whether an NPA portfolio is cost-effective?

A. As with NWS, the Company evaluates an NPA portfolio using the Societal Cost Test ("SCT") according to the guidance in the Benefit Cost Analysis Framework Order.[29]

[29] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision*, Order Establishing the Benefit Cost Analysis Framework (Issued January 21, 2016), p.12.

Q. How does the Company propose recovering the costs associated with NPA?

A. Please refer to the Accounting Panel testimony.

Q. What other accounting treatments does the Company propose for NPA?

A. As further provided in the 2020 Rate Case Order, the Company’s costs for NPA implementation, including the overall pre-tax rate of return on such costs, will be recovered as a regulatory asset. Similar to its proposal in the Targeted NPA Petition, the Company is proposing an amortization period of 20 years for the regulatory asset. The Company also clarifies that in the event an NPA portfolio is not viable, it will continue to treat the spending associated with the project up to that point as a regulatory asset. A single amortization period for the NPA portfolio also provides administrative and accounting consistency and simplicity.

Q. Is the Company proposing an incentive mechanism for NPA projects?

A. Yes. The Company is proposing a performance incentive mechanism designed to drive NPAs that provide meaningful achievement and net benefits to customers. This mechanism mirrors the approach currently in place for NWS, where shareholders retain a portion of the net societal benefits of each NWS, as measured using the BCAH. The four key components of the incentive proposal are:

1. An Initial Incentive where shareholders retain 30 percent of the Initial Net Benefits, and customers retain 70 percent as determined by the SCT performed prior to NPA implementation;
2. A bounded, Cost-Containment Incentive that rewards the Company for reducing costs during NPA implementation or penalizes it for cost overruns, with a cap such that the Final Incentive cannot exceed 50 percent of the Initial Net Benefits and a floor of $0;
3. A provision to address a situation in which an NPA project is not able to defer or eliminate the traditional project as initially intended; and

4. Provisions for a change in NPA Portfolio sizing needs for an active NPA project.

The Company’s proposed performance incentive structure represents a reasonable distribution of benefits because gas customers receive a majority of the net societal benefits. Moreover, the incentive encourages the Company to pursue NPA projects to maximize net societal benefits. Finally, the inclusion of the cost-containment provisions rewards the Company for cost-effective implementation of the NPA.

Q. Has the Commission approved similar incentive mechanisms for other New York State gas utilities?

A. Yes. The Company’s proposed performance incentive is nearly identical to that approved by the Commission in the New York State Electric & Gas and Rochester Gas & Electric rate case.[30] The Commission authorized a similar incentive for

[30] Case 19-E-0378 et. al, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of the New York State Electric & Gas Corporation for Electric Service, Order Approving Electric and Gas Rate Plans in Accord with Joint Proposal, With Modifications (issued November 19, 2020) P. 161 and Appendix HH.

Central Hudson in 2018[31] and reaffirmed that treatment in 2021.[32]

Q. How will the Initial Incentive be determined?

A. The Initial Incentive is determined by the Initial Net Benefits, which are simply the sum of the NPV of the societal benefits less the NPV of the societal costs. Initial Net Benefits will be calculated at the time when the Company submits its BCA to Staff. Similar to NWS projects, the Company will submit its BCA to Staff when it has entered into contracts with solution providers for the entire portfolio or is confident in the costs of the NPA portfolio.

Q. Can you describe the mechanism of the cost containment incentive?

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[31] Case 17-G-0460 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (Issued June 14, 2018).

[32] Case 20-G-0429 et. al, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plan (Issued November 18, 2021).

A. The Final Incentive will be determined by the actual project spending, subject to the Cost Containment Incentive. The Final Incentive is, in a simple case, the sum of the Initial Incentive and 50 percent of the difference between planned costs and actual costs. The Final Incentive is bounded such that it will not exceed 50 percent of the Initial Net Benefits and will not be negative.

Q. Over what period will the Company collect the NPA incentive?

A. The Company also proposes a collection schedule for the incentive that matches the NPA Deferral/Elimination Period. The NPA Deferral/Elimination Period begins when the Initial Net Benefits are set and extends 12 months past the time that the NPA portfolio delays or eliminates the traditional infrastructure build, as determined at the time of setting the Initial Net Benefits. The Company will begin collecting the Initial Incentive once 70 percent of the NPA portfolio is operational, measured in Dth/Day of load relief on the Design Day. The incentive will be amortized over the remaining NPA Deferral/Elimination Period (*e.g.*, if 70 percent of NPA portfolio is operational in the third year out of a five-year Deferral/Elimination Period, the incentive will be recovered over the remaining two years of the Deferral/Elimination Period). The Company will collect all incentive payments, inclusive of the overall pre-tax rate of return, through the Monthly Rate Adjustment (“MRA”), using the same cost recovery mechanism described in the Company’s current Rate Plan for other program costs. For clarity, the Deferral/Elimination Period when the NPA project is actively deferring the need for traditional infrastructure may differ from the Amortization Period, the length of time over which NPA project costs are recovered.

Q. Will the Company continue to collect an incentive if the NPA cannot defer or eliminate the need for the traditional project?

A. No. Recovery of any incentive, if applicable, will be halted, without requiring a refund of amounts collected to date, if at any time it is determined that continuing the NPA project is operationally or technically infeasible or unable to defer or avoid the need for the traditional project.

Q. Can you describe the process for adjusting the incentive if the size of the NPA portfolio changes after the Initial Incentive is established?

A. The Company proposes an additional series of adjustments to protect customers and incentivize cost-effective NPA implementation when the size of the NPA changes after its initial planning process. In such cases, where there is a material reduction in NPA portfolio sizing, the Company will plan to reduce its NPA procurements accordingly, to the extent contractually feasible. However, given the lower volume of need, the Cost Containment Incentive may overcompensate the Company under this scenario. To protect customers in this case, the Company suggests converting the incentive calculations into per unit incentives in $/Dth/Day. This process will align incentives for customers and the Company. As in the case where the NPA size does not change, the Company proposes that the Final Incentive be bounded such that it cannot fall below zero and cannot exceed 50 percent of the Initial Net Benefits.

Where the Company's reliability assessments indicates that the NPA portfolio must be larger than that proposed in the Implementation Plan, expressed in terms of deferring traditional infrastructure, the Company will seek to increase NPA procurement accordingly. However, the Company does not propose any change in the Final Incentive calculation from the initial need specified in the Implementation Plan. The Final Incentive should be calculated on a net benefits basis, adjusted for the Cost Containment Incentive, and bounded at zero and 50 percent of net benefits.

Q. Is the Company's NPA proposal intended to supplant any guidance that the Commission may provide in the pending Statewide Gas Planning Proceeding (20-G-0131)?

A. No, the Company's proposed treatment of NPAs would only apply to any NPAs considered and implemented prior to the Commission issuing guidance under Case 20-G-0131 and only to the extent that the Commission's guidance does not address a particular issue relating to NPAs.

iii. Demand Response

Q. Please describe the Company's demand response programs.

A. The Company offers and operates a suite of electric demand response programs. These programs are available to individual customers and third-party market participants ("Aggregators") and focus on supporting reliability and reducing costs of operating the electric distribution system. The programs operate during the summer Capability Period throughout the Company's service territory.

In addition to our longstanding Commercial System Relief Program and Distribution Load Relief Program, the Company recently introduced Term- and Auto-DLM programs where Aggregators can sign multi-year contracts to provide load relief at a fixed dollar per kW value of compensation ("Incentive Rate"), determined through a competitive procurement process. The Term-DLM program is a peak shaving program. Auto-DLM is a contingency program in which customers also provide peak shaving by participating in Term-DLM events when called.

iv. Demand Management Labor Request

Q. Is the Company requesting O&M to support its Demand Management programs?

A. Yes. The Company requests an addition of 15 FTEs to support the growth of its NPA and Demand Response portfolios. NPAs account for seven of the FTEs, Demand Response programs account for four of them, and incremental support from functions shared with Energy Efficiency account for the remaining four.

Q. Please explain the seven FTE request for the NPA portfolio.

A. These FTE’s will help implement the four NPA opportunities as well as identify, develop, and execute additional NPA’s during the rate period.

Implementation requires developing and running market solicitations to procure market solutions; contracting solution providers and managing contract performance; efficiently integrating Company gas EE and clean heat offerings into NPA portfolios via locationally-targeted incentives, sales, and marketing; integrating the various demand management solutions into a cost efficient portfolio that reliably meets the system need; validating and processing of incentive payments for completed projects; and tracking of performance and periodic rebalancing of the NPA portfolio as needed.

As the Company continues to evaluate all suitable traditional projects for NPA opportunities, these FTEs will identify, develop, and implement new NPA portfolios. Furthermore, we expect most of the NPAs over the next rate period to be Main Replacement Program (“MRP”) NPAs, which require greater effort and time to develop and manage because they are identified and implemented at the individual street level. MRP NPAs require the Company and market participants to engage with, and successfully electrify every gas-consuming building in the project location.

Q. Please explain the need for four FTEs for Demand Response.

A. AMI deployment has expanded DR eligibility to all customer segments, including residential and small business. Additional FTE’s will be needed to support and manage expected 5x growth of customer enrollment through 2025 that has been unlocked by AMI. Even with the efficiencies that have been and will continue to be realized through DRMS, this growth will increase the work required to enroll, dispatch, and settle participants; provide customer service; manage the annual network specific procurements for the DLM program; and administer these DLM contracts.

Q. Please explain the four FTE request for incremental support from functions shared with Energy Efficiency.

A. Two FTEs will provide Evaluation and Measurement for the NPS portfolio to run analyses and studies confirming realization of gas peak reductions procured from the market and provided by EE programs. The remaining two will provide financial and analytical support for NPA portfolio development, including budgeting, BCA analyses, and customer analyses.

Q. Has the Panel developed an exhibit to further explain its Demand Management O&M request?

A. Yes. A 6-page document entitled Energy Efficiency & Targeted Demand Management O&M, Exhibit __ (CES-6), was developed under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-6)

C. Advanced Metering Infrastructure (AMI)

Q. Please describe the status of Con Edison’s AMI initiative.

A. Con Edison has been deploying AMI across its service territory. AMI implementation involves the following principal steps: (1) building the AMI Information Technology (“IT”) platform and developing the system interfaces between the AMI IT platform and legacy applications; (2) installing the AMI communications network for territory-wide coverage; and (3) installing approximately 3.7 million electric smart meters, retrofitting 950,000 gas meters with AMI modules, and replacing approximately 210,000 gas meters with meters equipped with AMI modules (these 210,000 include tin case gas meters that cannot be upgraded with a new meter and AMI module and meters that need to be remediated due to performance).

The Company had forecasted completing these steps in 2022. Notwithstanding pandemic related issues, the Company completed deployment of most advanced meters and planned platform technology systems by the end of 2021. That is, the Company installed approximately 4.44 million of the 4.85

million meters and the communications systems are operating, including using meter reading information to bill customers.

Q. Given this progress, will the Company complete the initiative in 2022 as it originally forecasted?

A. The Company currently estimates that roughly 80,000 meters will not be installed by the end of 2022, along with some correlating communications work to optimize the network. As a result, the Company expects that a small portion of the project will carry over into 2023. The costs for the project, however, will remain within the overall cap.

Q. Please explain why certain meters will not be installed by the end of 2022.

A. Generally, some customers are not allowing access to premises. Most of the remaining meters will have had five or more installation attempts. This is despite our active follow-up process in no access situations.

The Pandemic extended the schedule because we suspended meter deployment activities from March to June and then had gradually ramped-up deployment once the suspension was lifted.

During 2022, the Company plans to do additional work to install these meters but projects that there could be approximately 80,000 meters remaining to be installed in 2023. We forecast that we will be able to complete the remaining meters in 2023.

Q. Please explain the additional communications and other work needed.

A. Con Edison plans to improve the performance of the communications network during 2023. As we continue to complete mass deployment of the remaining no access meter population, additional network devices (Access Points (APs), Relays, or socket APs) will need to be installed. This final process of network optimization is to confirm there are no gaps in the AMI network.

Finally, Con Edison will incorporate AMI system improvements, such as power quality enhancements and additional integration into our Enterprise Data Analytics Platform (EDAP), to monitor system performance.

Q. Has the panel prepared an exhibit describing its proposed AMI improvements?

A. Yes. A 7-page document, entitled AMI Capital and O&M 2023-2025, Exhibit __ (CES-7), has been prepared under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-7)

Q. Please describe how the Company’s investment in AMI will be reflected in the upcoming rate period.

A. The AMI Project will cost $31.5 million in 2023. At update, the Company will advise if additional funding needs to be shifted into 2023 based on meter exchanges by that date. This will not cause the total cost of the AMI project to exceed the Commission-approved capital funding allowance of $1.285 billion for AMI.

Q. What are the O&M costs associated with AMI?

A. Table 14 presents the estimated O&M costs. The AMI Project O&M expenses are annual recurring expenses required to maintain the AMI systems and communications infrastructure. AMI expenses include: AMI Operations Control Center labor for 24/7 system monitoring; post implementation and IT system labor support; communications infrastructure and meter maintenance; and AMI IT system maintenance and hosting. The AMI O&M expenses are in line with the business case.

Table 14: O&M Costs for AMI

($000)

	2023	2024	2025
O&M	$49,217	$50,201	$51,205

VI. Implementing Clean Energy Programs

Q. Please explain what is covered in this section.

A. This section explains the ongoing and expected work associated with NENY programs, including Clean Heat, requests continuing regulatory asset treatment for program expenditures, proposes adjusting the amortization period for the Clean Heat program to match the useful life of the heat pump equipment, explains our incremental labor request, and discusses expanding EE programs to NYPA.

A. Energy Efficiency and Heating Electrification

Q. Please describe the Company’s energy efficiency programs.

A. Con Edison has a portfolio of Non-LMI electric and gas EE programs available to residential customers, multi-family buildings, and commercial and industrial customers. The Company also has dedicated budgets and EE programs to serve LMI customers. These programs use financial incentives, marketing, and technical support to spur customer adoption of various EE measures. Based on Commission estimates, the Non-LMI electric and gas EE programs are expected to save over 3,900,000 MWh of electricity and over 5,600,000 MMBtu of gas between 2020 and 2025.[33] Despite the challenges of the COVID-19 pandemic, the Company exceeded its combined electric and gas non-LMI NENY energy efficiency goals by 26% during 2020-2021, representing an additional 1.6 million lifetime metric tons of carbon reduced.

Q. Please describe the Company's heating electrification program.

A. As noted earlier, the Company is part of the Statewide Clean Heat program portion of NENY, aimed at increasing heating electrification. The Clean Heat program has a cumulative savings target of 1 TBtu of net site energy savings from

[33] NENY Proceeding, Energy Efficiency Order, Appendix A.

2020–2025.[34] In 2020-21, the Clean Heat program and its market partners installed electric space or water heating in 12,684 buildings.

Q. How has the Company been able to achieve these results for EE and Clean Heat programs?

A. The Company achieved these results through program innovation, new program launches, expanded customer and market engagement, operational efficiencies, and collaborative efforts.

Q. What are the Company's growth plans for its EE and heating electrification portfolios through 2025?

A. The Company's 2021 System Energy Efficiency Plan (SEEP) explains our plans to increase program investment from $279 million in 2021 to $389 million in 2025. Given the accomplishments in NENY and Clean Heat so far, the Company will request in the NENY proceeding additional funding authorizations with increased Clean Heat savings goals.

[34] NENY Proceeding, Energy Efficiency Order, Appendix C.

Q. Is there anything that the Company needs in this filing to assist with NENY and its expected higher goals and spending?

A. Yes. We explain our cost recovery and labor requests below.

i. Program Cost Recovery

Q. Turning first to cost recovery, how will currently authorized NENY program costs be recovered during 2023-2025?

A. Recovery is via base rates consistent with the NENY Order and Commission policy. The Company proposes to continue to amortize NENY program costs to generally match program recovery with the useful life of the program’s EE and heat pump investments, as the Commission approved in the Company’s last rate case. This approach benefits customers by mitigating the annual customer bill impacts of the EE and Clean Heat portfolio budgets, matching cost recovery with the realization of the benefits these investments create.

Q. What amortization period(s) does the Company propose to use for these capitalized expenditures and why?

A. For Electric and Gas EE programs, we propose to continue using a 10-year amortization period, which is consistent with the average lifetimes of the EE equipment these programs support.

The Company proposes changing the Clean Heat amortization period to 15 years. A 15-year period is more consistent with the lifetime of heat pump equipment, which has a minimum useful lifetime of 15 years.

Q. What flexibility will the Company have to move program spend between years or NENY program categories?

A. The Company will have the flexibility outlined in the NENY Order. This includes the ability to shift budgets from year to year within portfolios and among programs within the same portfolio (e.g., within the non-LMI Electric EE portfolio). The Company also has contingent flexibility to shift between electric, gas, and heat pump budgets once the Company has demonstrated it will meet the annual target for the portfolio from which funds are being transferred. While funds cannot be transferred from LMI to non-LMI programs, non-LMI program funds can be transferred from non-LMI to LMI programs per the contingent flexibility described above.

Please see the Accounting Panel testimony for detail on the reconciliation.

Q. How will any additional program budget authorization under the NENY proceeding be addressed by this rate plan filing?

A. The Company will treat expenditures authorized under NENY, incremental to levels currently authorized in the NENY Order, as regulatory assets amortized over the same time periods identified above. The Company will propose in the NENY proceeding recovery of any such expenses via surcharge.

ii. Labor Request

Q. Is the Company requesting additional labor O&M to support the growth of its EE and Clean Heat portfolios?

A. Yes. The Company requests incremental O&M to cover an additional 33 FTEs to support the growth of its EE, LMI, and Clean Heat portfolios. These consist of 23 program management and implementation FTEs, and 10 support function FTEs, spanning business planning, portfolio management, financial analysis, benefit cost analysis, data, analytics, and evaluation, measurement & verification.

Q. Please explain this request.

A. First, the Company's EE, LMI, and heat pump efforts require additional headcount to successfully plan, implement, and manage these programs. For example, each new program requires market research, analysis, business planning, and design to launch; program management staff to drive performance, including engagement with market actors that can include manufacturers, distributors, retailers, contractors, and/or customers; and ongoing engineering, evaluation, measure & verification, financial, data and analytics, and compliance support. One such new program is the launch and integration with Clean Heat of the Heating Electrification Make-Ready program discussed earlier in this filing.

Second, the sources of savings will increase in complexity relative to the historical portfolio because of the complexity of the underlying technologies and the customer segments to target. The increased complexity requires additional headcount to manage. For example, the Company will reduce its reliance on lighting savings and significantly grow savings coming from deeper, more complex sources of savings, like building envelope upgrades, the electrification of heat and hot water, and implementing advanced controls. These new sources of savings are required to achieve the CLCPA’s climate goals as the LED lighting market saturates. These new sources of savings are more complex for customers to implement compared to lighting upgrades. Larger financial investments requiring longer planning, greater design & engineering, and careful coordination to avoid tenant disruption. They are, similarly, more complex from a program administration standpoint.

Q. Please provide examples of the expected work.

A. To increase Clean Heat participation from multifamily buildings and commercial buildings, the Company must support building owners undergoing heating system upgrades to help them undertake unfamiliar and complex upgrades to their building’s mechanical and electrical systems instead of a boiler replacement. We will need to increase our marketing and sales efforts to reach building owners considering an upgrade, improve engagement with market partners to support decision making changes, and affirm engineering efforts to calculate and validate savings for these solutions.

Because the Company will grow its programs targeted at LMI customers, we will need additional financial and technical support to guide these customers through installation.

Q. How will the Company recover NENY O&M and labor costs during 2023-2025?

A. NENY authorized program budgets, but not the costs of Company labor to manage these programs. Labor, operations, and maintenance costs to support the NENY programs are expensed as O&M and collected in rates as incurred. The Company notes the challenge this practice poses with the expected adjustment of budgets and targets in the NENY Interim Review during this rate plan. If NENY budgets and goals increase, the Company will lack the O&M to support this growth, putting achievement of these goals at risk. To avoid this outcome, we believe that NENY should provide the funding and flexibility to fund labor needs. However, in the current absence of this flexibility, the Company requests an incremental O&M increase to address these needs in this filing.

Q. Has the Panel developed an exhibit to further explain this incremental O&M request?

A. Yes. Please refer to Exhibit __ (CES-6) introduced above.

Q. Is there additional information available about Exhibit __ (CES-6) that should be noted?

A. This exhibit explains the need for 48 FTEs across Energy Efficiency and Demand Management. The Company is continuing to review this and at this time, the funding request is a reasonable forecast, but the explanations do not reflect the full request. The Company expects to provide additional information detailing this request in the course of discovery.

Q. Does the Company compensate any employees in its EE group based on a variable structure different from the management variable pay component used for other non-officer management employees?

A. Yes. The Company’s EE business development managers who sell to commercial and industrial customers as well as multifamily portfolio customers receive a base salary, but their variable component uses a pay-for-performance formula based on energy savings delivered. The Company adopted this compensation approach for these specific employees to match competitive compensation packages available for similar roles at other businesses. This parity in pay structure allows the company to hire talented and driven business development managers capable of building relationships with customers and increasing participation in the Company’s programs.

iii. Expanding access to EE and clean heating

Q. Are NYPA customers currently eligible to participate in Con Edison’s electric EE and Clean Heat programs?

A. No. While NYPA customers with Con Edison gas service are eligible to participate in gas EE programs, NYPA customers do not participate in electric EE and heat pump programs because they do not contribute to the costs for these programs.

Q. Does the Company propose to change these eligibility restrictions?

A. Yes. The Company proposes to open eligibility of its NENY Electric EE and Heat Pump programs to NYPA customers.

Q. How does the Company propose to allocate the costs associated with NYPA customer participation in these programs?

A. As shown in Table 15 below, the Company will allocate costs associated with NYPA customer participation in these programs to all NYPA customers. Half of the costs associated with NYPA customer projects located in a Disadvantaged Community, i.e., predominantly NYCHA residents, would be allocated to NYPA customers, and the remaining half would be allocated to non-NYPA customers.

Table 15: Cost Allocation for NYPA Customer Participation in Energy Efficiency and Clean Heat Programs

	Cost Allocation	
	All NYPA Customers	**All Non-NYPA Customers**
NYPA Customer Project in Disadvantaged Community	50%	50%

NYPA Customer Project Outside Disadvantaged Community	100%	0%

Q. Why should NYPA customers be permitted to participate in EE and Clean Heat programs?

A. Electric and gas users should be eligible for support in helping to meet and achieve state and City EE and clean heat goals. Our NENY related programs are expansive and many NYPA customers could benefit from the support they offer. Furthermore, many NYPA customer facilities are core institutions within Disadvantaged Communities, including schools, first-responder stations, community centers, housing, transit hubs, and housing shelters. With the CLCPA's emphasis on including disadvantaged communities in the clean energy transition, expanding eligibility would allow these facilities to benefit from statewide programs.

Q. The Panel mentioned earlier that non-NYPA customers should pay 50 percent of the EE and Clean Heat program costs for NYPA customer participation in Disadvantaged Communities. Please explain why.

A. The CLCPA prioritizes public policy investment in Disadvantaged Communities to help all New Yorkers benefit from the clean energy transition. By supporting EE and heating electrification for critical social services (*e.g.*, primary and secondary schools, police stations, community centers, homeless shelters, vaccination sites, and low-income housing), all customers are investing in support of this State policy goal. Benefits of heating electrification and EE investments in these Disadvantaged Community locations accrue to the broader community around them – and even more so because many of these locations are public access or provide public services that all customers rely on.

Q. Does this proposal increase funding for NENY programs outside of the NENY proceeding?

A. No. This proposal will make NYPA customers eligible for NENY programs under the authorized NENY program budgets. It does not increase program budgets or impact overall revenue requirement. As discussed earlier in this testimony, Company requests for additional NENY program funding and targets will be under the NENY proceeding.

Q. Does the Company have an estimate of the costs to be allocated to NYPA customers or non-NYPA customers based on their participation in these programs?

A. The Company plans to provide additional details on its proposed allocation of cost at the update stage of this proceeding. To the extent tariff changes are necessary, those will also be identified in the Update filing. In the interim, the Company will engage with NYPA and its customers to further discuss the best way to implement this proposal. The proposal will have a minor impact on the overall cost paid by NYPA vs. Con Edison customers, and will not affect the overall revenue requirement.

B. Electric Vehicles

Q. Please describe the Company’s Electric Vehicle Charging Make-Ready program.

A. The Electric Vehicle Charging Make-Ready program, authorized by the Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs, encourages developers to install increasing amounts of EV chargers by providing incentives of up to 100 percent of the costs of making EV charging sites ready for charger installation. The program incentivizes the installation of infrastructure supporting two types of chargers: slower Level 2 (“L2”) plugs which are typically found at multifamily dwellings, workplaces, parking garages, curbsides and at commercial areas, and faster Direct Current Fast Chargers (“DCFC”) that are typically found at areas such as urban charging hubs serving multiple customer types. Make ready costs include utility-owned equipment, such as traditional distribution infrastructure, overhead service lines, and utility meters, as well as customer-owned equipment and costs such as conductors, trenching, and panels needed for the station.

Q. How will program costs authorized by the Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs be recovered during the Rate Plan?

A. Expenses for customer-owned make-ready work will be recovered as a regulatory asset over a period of 15 years and collected through an existing surcharge mechanism. Expenses for program implementation will be recovered as a regulatory asset over a period of five years. Utility-owned new business and make-ready work, including work related to future-proofing utility infrastructure, will be treated as capitalized plant in service (these expenditures are discussed further in the EIOP Testimony). Please refer to the Accounting Panel for further detail on cost recovery

Q. Are there additional EV expenditures being recovered during this rate plan?

A. Yes. The Company requests incremental O&M to support EV expenses outside of program activities being conducted pursuant to NY PSC Orders. Expenses will be used toward studies to better understand the nexus of customers and clean transportation, with a particular emphasis on ideas to better enable Disadvantaged Communities to access the benefits of clean transportation.

Q. Has the Panel developed an exhibit to further explain this incremental O&M request?

A. Yes. A 5-page document entitled EV Market and Technology Development Whitepaper, Exhibit___(CES-8), has been prepared under our direction and supervision.

MARK FOR IDENTIFICATION AS EXHIBIT __ (CES-8)

VII. <u>Promoting Clean Energy Outcomes</u>

Q. Please describe the mechanisms by which the Commission encourages the Company to promote clean energy outcomes.

A. As part of the REV Proceeding, the Commission adopted various mechanisms to align utilities' business interests with clean energy policy objectives. The Commission authorized the development of and adopted Earnings Adjustment Mechanisms ("EAMs") to provide meaningful economic incentives for achievement of various policy outcomes, such as reducing peak demands for electricity and, more recently, natural gas, and achievement of certain programmatic targets.

Q. What EAMs are currently in place for Con Edison?

A. The Company's current rate plan consists of seven EAMs:

- Share the Savings ("STS"): Incentivizes overachievement of non-LMI NENY EE goals and driving unit cost efficiency;

- Deeper Energy Efficiency (“Deeper EE”): Incentivizes driving EE and electrification savings to more challenging and more expensive measures (*e.g.*, non-lighting measures);
- Beneficial Electrification: Incentivizes driving higher adoption of heat pumps and electric vehicles to electrify end uses;
- DER Utilization: Incentivizes interconnecting MWs of DER (*e.g.*, solar and battery storage) above forecasts to reduce GHG emissions and develop the customer sided resources for a more resilient and flexible grid;
- Electric System Peak: Incentivizes driving overall system peak reductions beyond forecasts to reduce GHG emissions, mitigate the need for system coincident infrastructure, and reduce stress on the grid during system coincident peak times to improve reliability;
- Locational System Relief Value (“LSRV”)) Load Factor: Incentivizes improving the load factor, the ratio of a network’s consumption divided by the area’s MW capacity

multiplied by 8,760 for the numbers of hours in year; and

- Gas System Peak: Incentivizes driving firm gas system peak reductions to reduce the Company’s gas supply needs.

Q. Please describe the Company’s performance under those EAMs.

A. In 2020, the Company exceeded its minimum targets for the Share the Savings, Deeper EE, Electric System Peak and Gas System Peak EAMs. The Company achieved these outcomes through launching the new Clean Heat program, building awareness of the Company’s programs, and working with market participants and customers to complete more EE and heating electrification projects. The Company did not achieve the minimum targets for the DER Utilization and LSRV Load Factor EAMs. Data related to Beneficial Electrification is still under review. The Company expects to file the annual report on its 2021 EAM achievements on March 31, 2022.

Q. Has the panel prepared an exhibit describing its proposed EAMs?

A. Yes. A 48-page document, entitled EAM Exhibit, has been prepared under our direction and supervision.

MARK FOR IDENTIFICATION AND EXHIBIT __ (CES-9)

Q. How many EAMs does the Company propose?

A. The Company proposes 11 positive earnings adjustments, calculated as return on equity basis points, for each of the EAMs. Overall, the proposed annual EAM earnings opportunities are set at 65 basis points for electric and 58 basis points for gas during each year of the rate plan. Exhibit __ (CES-9) breaks down the allocation of these earnings opportunities to each specific EAM and quantifies the respective benefits and costs.

Q. Describe which policy objectives the proposed EAMs support.

A. The Company's proposed EAMs in this testimony build on lessons learned and take new state policy objectives into account. The Company's proposed EAMs incentivize utility activity to accelerate and overachieve important policy objectives, such as: (1) growing EE and DER; (2) lowering electric and gas system peak to achieve Statewide delivery system efficiencies; (3) reducing GHG emissions; (4) driving savings and benefits to LMI customers and Disadvantaged Communities; and (5) transitioning to an electrified economy by promoting beneficial electrification, which will move customers away from fossil fuels.

Q. Describe the Company’s general approach to target setting.

A. The core concept for EAMs is the principle that they should incentivize Company activity above and beyond expected achievement due to normal course of business (a “baseline”) to accelerate achievement of policy objectives. Given this principle, the Company generally follows one of two approaches to establish the baseline: 1) the baseline represents planned achievement according to Company filings, investment plans, or mandated targets or 2) the baseline represents the extrapolation of a trendline based on historic performance. Once the Company establishes the baseline, it develops minimum, midpoint, and maximum targets that are both meaningful and achievable. Specific targets and details on how they were developed for each EAM are outlined in Exhibit__(CES-9), “EAM Exhibit”.

Q. Please summarize the Company’s proposed EAMS.

A. The following tables summarize the proposed EAMs in three categories: (1) apply to both electric and gas operations (cross-commodity), (2) apply to electric, and (3) apply to gas. These EAMs support the State’s clean energy goals set forth in the CLCPA.

Table 16 - Cross-commodity EAMs

EAM	**Purpose**	**Metric**	**Basis Points**
Electric Share the Savings (modified)	Increase EE savings while driving cost efficiency to support the CLCPA’s goal to achieve 85% reduction in GHG emissions by 2050	Lifetime MMBtu savings AND $/Lifetime MMBTU savings	NA
Gas Share the Savings (modified)	Increase EE savings while driving cost efficiency to support the CLCPA’s goal to achieve 85% reduction in GHG emissions by 2050	Lifetime MMBtu savings AND $/Lifetime MMBTU savings	NA
Deep Savings (modified)	Increase savings from difficult, more expensive “deeper” EE and building electrification measures important for achievement of CLCPA 85% reduction in GHG emissions by 2050	Lifetime MMBtu savings	Min: 3 Mid: 9 Max: 15

Low-Income Customers & Disadvantaged Communities (new)	Overachieve LMI EE targets and drive greater than CLCPA target of 35% of benefits of investment to Disadvantaged Communities to increase participation of LMI and Disadvantaged Communities customers in the benefits of the clean energy transition	Annual MMBtu savings	Min: 3
			Mid: 6
			Max: 10

Table 17 - Electric-Only EAMs[35]

EAM	**Purpose**	**Metric**	**Basis Points**
Demand Response (new)	Increase participation in DR program to promote grid flexibility	Annual number of SC1 and SC2 customers enrolled, and performance factor is above 25% in the Company's DR programs	Min: 1
			Mid: 3
			Max: 5
Transportation Electrification	Support and foster transportation		Min: 2

[35] This table does not include the Company's Electric Vehicle Make Ready Share the Savings EAM that the Commission established outside of the Rate Case process and is not part of this Rate Case filing.

(modified from Beneficial Electrification EAM)	electrification that advances State’s clean energy policy goals related to EV adoption	Avoided carbon emissions from EVs	Mid: 4 Max: 7
Conservation Voltage Optimization (CVO) (new)	Increase and accelerate CVO energy savings	Annual percent energy savings from CVO	Min: 3 Mid: 6 Max: 10
DER Utilization (modified)	Support solar and energy storage development in support of New York State’s commitment to install 6,000 and 6,000 MWs of solar and storage respectively by 2030	Incremental, annualized MWh of production for solar and charge and discharge for battery storage	Min: 2 Mid: 6 Max: 10
Electric Peak Reduction	Reduce CECONY peak usage	Actual weather normalized NYCA coincident system peak for the Company’s service territory, as determined by NYISO	Min: 3 Mid: 5 Max: 8

Table 18 - Gas-Only EAMs

EAM	**Purpose**	**Metric**	**Basis Points**
System Footprint (new)	Decrease gas system footprint with an increased focus on	Ratio of installation footage over	Min: 5 Mid: 15

	main elimination in the Main Replacement Program (MRP)	leak-prone pipe (LPP) abandonment footage	Max: 25
Gas Peak Reduction	Deliver firm gas system peak reductions to reduce the Company's gas supply needs and improve overall gas system efficiency	Seasonally adjusted gas peak demand	Min: 3
			Mid: 5
			Max: 8

Q. Has the Company quantified the benefits and costs associated with its proposed EAMs?

A. Yes. The EAMs are cost beneficial and represent a modest share of the total net benefits created. Please refer to Exhibit __ (CES-9) for a breakdown of the benefits and costs for each respective EAM.

Q Please describe how historical EAM performance and new policy objectives have informed the Company's proposal.

A. The Company's EAM proposal is informed, first, by the CLCPA, and second, by the lessons learned from the existing EAMs. For CLCPA alignment, the Company assessed if each existing EAM drives over- or earlier-than-mandated achievement of

CLCPA goals, and/or drives above “business as usual” achievement of outcomes critical to achieving the clean energy transition. Second, the Company assessed the lessons learned from each EAM to test whether the EAM is 1) effectively drives the intended outcomes, 2) is measurable, and 3) the Company has some degree of influence.

Q. Please continue.

A. In terms of lessons learned, the Company’s current EAMs and associated performance informed the EAM proposal in this rate filing in five ways.

First, the Electric System Peak Reduction EAM benefits society as it reduces GHG emissions from “peaker” plants, which have higher emission intensities, and help to reduce capacity costs. The metric is sufficiently straightforward in its calculation and the Company’s actions and influence to drive MWs of system peak reduction are appropriately linked to EAM achievement. We propose to continue this metric with minor modifications to how targets are set.

Second, the Share the Savings (STS) and Deeper EE EAMs are metrics that together demonstrated effectiveness at driving utility performance against NENY goals. The STS metric drove both overachievement of EE goals and unit cost efficiencies. The Deeper EE metric effectively complemented STS to mitigate the disincentive from STS to drive more expensive but important measures and effectively pushed the EE and electrification portfolios in this direction. We propose to retain these metrics with modifications such as narrowing their respective scopes to less mature sources of EE and building electrification savings and excluding gas devices savings to better align them with current State priorities and the dynamics of a transforming energy market.

Third, the Beneficial Electrification and DER Utilization EAMs support key State policy objectives. The Company proposes modifications to the DER Utilization EAM to address uncertainties in the solar and battery storage markets in target setting. In addition, the Company proposes to narrow the Beneficial Electrification EAM to electric vehicles and remove heat pumps to reduce overlap with the proposed Deep

Savings EAM (which will reward overachievement of heat pump targets).

Fourth, the Gas Peak EAM encourages the Company to focus on winter gas peak management to reduce upstream supply obligations and increase the efficiency of the gas system. The metric is sufficiently straightforward in its calculation and the Company's actions and influence are appropriately linked to EAM achievement. Therefore, the Company proposes to retain the Gas Peak EAM without modification.

Finally, the LSRV EAM fell short of achieving the intended outcomes and the Company proposes to discontinue this EAM. The current LSRV metric disincentivizes many kinds of EE and solar technologies which the Company believes are core priorities for achieving CLCPA goals. The LSRV EAM metric measures the ratio of a network's consumption divided by the area's MW capacity multiplied by 8,760 (number of hours in a year). As a result, this EAM rewards the Company for limiting solar development in LSRV areas, as solar reduces electric consumption, but only reduces peak demand in networks with peaks coincident with solar production. Furthermore, the proposed Demand Response EAM and the NWS framework will more effectively drive Company focus on the integration of customer sided solutions to reduce distribution system peaks and defer or reduce traditional infrastructure needs.

A. Proposed EAMs

i. Electric Share the Savings ("Electric STS")

Q. Please describe the goal of the Electric STS metric and how it is aligned with policy objectives.

A. The Electric STS metric encourages the Company to overachieve non-LMI electric EE targets while driving unit cost efficiencies and focus the Company on further growing electric EE in areas outside of residential lighting. Growing savings in these other areas, is important for achievement of the CLCPA's goal to drive an 85% reduction in GHG emissions by 2050 and to reduce 22 million tons of carbon through EE and electrification.

Q. Please describe how the Company will measure this EAM.

A. The Company will measure Electric STS EAM achievement by calculating the lifetime non-residential lighting energy electric efficiency savings that are acquired through the Company's non-LMI electric EE programs.

Q. Why does the Company propose to exclude residential lighting EE savings from the Electric STS EAM?

A. Residential Lighting savings are associated with any savings linked to the installation of efficient lamps or lighting fixtures through the Company's Retail Lighting and Marketplace programs which target residential customers. While lighting EE is an important component of our program, the Company's non-LMI residential lighting programs have matured. As EAMs incent activities beyond business as usual, the Company proposes to focus the Electric STS metric on rewarding the savings from developing less mature EE savings. Excluding non-LMI residential lighting savings from the Electric STS metric incents the Company to evolve its EE portfolio and focus on other sources of EE.

Q. Why is the STS construct not applied to building electrification savings?

A. The building electrification market is still in the early stages of development with continued rapid growth being important in achieving CLCPA goals. Furthermore, the Company and the statewide Clean Heat program are still introducing new program offerings and breaking into lower-participating customer segments (e.g., existing multifamily and commercial buildings). As a result, the Company believes an EAM focused on maximizing achievement better aligns with NYS policy goals than minimizing unit cost.

Q. How will the Company calculate the baseline for this EAM?

A. The Electric Share the Savings metric is formulaic (see Exhibit __ (CES-9) for details). The proposed baseline achievement is based on the Company's System Energy Efficiency Plan ("SEEP")[36] which details planned electric and gas EE savings through RY3 which is then adjusted to remove expected residential lighting savings. It is also important to recognize that the current savings targets

[36] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative,* Con Ed SEEP 2019 – 2025, filed December 23, 2021.

could change based on EE budgets and targets established in the NENY interim review or other Commission action in the NENY proceeding. The Company proposes formulas (see Exhibit __ (CES-9)) to scale the Electric STS baseline to reflect the results of the interim review.

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. Midpoint and maximum targets are not applicable to the Electric STS EAM as the incentive amount is determined by a formula after achievement of the minimum threshold.

Q. Does the Company propose an additional threshold of achievement to earn from the Electric STS metric?

A. Yes. The Company proposes that the Company must achieve its annual NENY non-LMI electric annual MMBtu goal to earn on the Electric STS metric. The Company proposes to use the targets established in the 2020 NENY[37] order until updated

[37] Case 18-M-0084, *In the Matter of a Comprehensive Energy Efficiency Initiative,* Order Authorizing Utility Energy Efficiency and Building Electrification Portfolios Through 2025 (issued January 16, 2020).

targets are set through the NENY interim review or other Commission action in the NENY proceeding.

ii. Gas Share the Savings (“Gas STS”)

Q. Please describe the goal of the Gas STS metric and how it is aligned with policy objectives.

A. The Gas STS metric encourages the Company to overachieve the non-LMI gas EE targets set by NENY while driving unit cost efficiencies. It is aligned with the CLCPA’s goal to drive an 85% reduction in GHG emissions by 2050 and to eliminate 22 million tons of carbon emissions through EE and electrification.

Q. Please describe how the Company will measure this EAM.

A. The Company will measure Gas STS achievement EAM by calculating the lifetime EE savings acquired through the Company’s non-LMI NENY programs excluding savings from efficient gas-consuming space heating equipment, water heating equipment, and cooking equipment and appliances, referred to here as “gas devices.”

Q. Why does the Company propose to exclude gas space heating, water heating, and cooking equipment and appliance efficiency savings from the Gas STS EAM?

A. To achieve the CLCPA emission goals, the State will reduce reliance on EE savings from efficient gas devices and emphasize building electrification savings. Because gas heating and cooking equipment often have long useful lives (15 years or more is common) incentivizing a customer to install, for example, a new, more efficient, gas fired boiler today could delay that customer's transition to electrified end uses and continue to produce emissions that are targeted by the CLCPA.

At the same time, the Company recognizes that EE programs should continue to support customers who find electrification difficult in the near term because the electric heating technology available today does not allow for a simple retrofit of certain building typologies. For example, tall buildings heated with steam produced by their gas boiler cannot easily replace the existing heating equipment with a heat pump. In these instances, the Company believes customers should pursue the most efficient gas heat and hot water equipment possible which the Company would continue to incentivize. Considering the tension laid out above, the Company proposes to exclude gas-device efficiency (space heating, water heating, and cooking equipment and appliances) from the Gas STS metric to encourage the gas portfolio to place greater emphasis on non-gas device EE activities, such as building envelope upgrades.

Q. How will the Company calculate the baseline for this EAM, including data sources the Company will use for baseline development?

A. The Gas STS metric is formulaic (see Exhibit __ (CES-9) for details). Like the Electric STS metric above, the Company proposes that the Company must achieve its annual NENY non-LMI gas annual MMBtu goal to earn on the Gas STS metric. The Company has also proposed a scaling formula in Exhibit __ (CES-9) for the Gas STS metric to account for possible changes to NENY budgets and targets from the upcoming interim review or other Commission action in the NENY proceeding.

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. Midpoint, and maximum targets are not applicable to the Gas STS EAM as the payout is determined by a formula after achieving a minimum threshold.

Q. Does the Company propose an additional threshold of achievement to earn from the Gas STS metric?

A. Yes. The Company proposes that the Company must achieve its annual NENY non-LMI gas annual MMBtu goal to earn on the Gas STS metric. The Company proposes to use the targets established in the 2020 NENY order until updated targets are set through the NENY interim review or other Commission action in the NENY proceeding.

Q. Why does the Company propose to exclude LMI savings from the Electric and Gas STS metrics?

A. As LMI building owners have less access to capital than market rate customers and have constraints on recouping investments due to appropriate rent regulations, the financial incentives for EE and building electrification upgrades are more important to implement projects. As a result, the Company believes there should be less emphasis on driving unit cost reductions for its LMI programs than for market rate programs which are covered by the STS metrics. The Company proposes to drive overachievement of LMI savings goals and maximization of LMI customer benefits through a separate EAM.

iii. Deep Savings

Q. Please describe the goal of the Deep Savings metric and how it aligns with policy objectives.

A. The Deep Savings metric encourages overachievement of the NENY heat pump targets and grows EE savings coming from more expensive, challenging measures, such as building envelope, advanced controls, and waste heat recovery measures, which the Electric and Gas STS metrics’ focus on reducing unit costs can disincentivize. For example, the Company’s budgeted non-LMI gas unit cost for 2023 is $39 per annual MMBtu saved. Going into 2022, the Company is increasing its incentive rate for envelope measures, where most of the associated savings come from saving natural gas, to $200 per MMBtu saved to spur additional activity as the Company has seen its existing incentive rate was insufficient to drive demand. The new envelope incentive rate will reduce earnings under the Electric and Gas STS metrics despite being a critical source of savings to develop to achieve CLCPA. Achieving both the building electrification required by CLCPA’s long-term goals and mitigating the impacts of future winter peak growth will require driving deep EE upgrades, like building envelope improvements.

Q. Has the Deeper EE EAM metric in place for the 2020 – 2022 Rate Period been effective at achieving its goal developing new sources of savings to position the Company to continue to drive EE and electrification savings at scale over the medium to long-term?

A. Yes. This metric has been effective developing the more challenging and expensive measures that are not strictly necessary for achieving goals today but will be critical to continue driving savings in pursuit of the CLCPA’s long-term goals. For example, the Company has increased its share of non-lighting savings in the electric portfolio from 28% in 2019, the year before the Deeper EE EAM was put in place, to roughly 56% in 2021.

Q. Does the Company propose to modify the Deeper EE metric from the 2020 – 2022 Rate Period?

A. Yes. The Company propose to narrow the definition of Deep to focus more on the most challenging and expensive, but important, savings sources. As the Company transitions to an electrified building stock, building envelope and advanced control measures will drive additional energy savings, mitigate the peak impact from electrifying heat and hot water, and develop buildings into grid resources to manage demand.

Q. Please describe how the Company will measure this EAM.

A. The Company will measure the Deep Savings metric by calculating the lifetime savings from its NENY Clean Heat programs and from other priority EE measures (e.g., building envelope) that the Company proposes to include in this metric. See Exhibit __ (CES-9) for more details.

Q. How will the Company calculate the minimum for this EAM?

A. The minimum is tied to the Company's lifetime heat pump SEEP targets and adjusted to include the lifetime savings targeted from growing other Deep Savings measures, with 3 BPs allocated for minimum achievement. The Company has also proposed a scaling formula in Exhibit __ (CES-9) for the Deep Savings metric which will be applied to both the targets and associated basis points to account for any Commission-Ordered changes to NENY targets during the rate plan.

Q. What are the proposed midpoint and maximum targets for this EAM?

A. The midpoint and maximum targets for this EAM are based on overachieving the minimum by 10% and 20%, respectively, for each Rate Year with basis points of 9 and 15 allocated to each, respectively.

iv. Low-Income Customers & Disadvantaged Communities

Q. Please describe the goal of the Low-Income Customers & Disadvantaged Communities metric and how it aligns with policy objectives.

A. The Low-Income Customers & Disadvantaged Communities metric is a new metric to encourage overachievement on the LMI EE targets set by NENY and to direct EE savings towards Disadvantaged Communities to exceed the 35% of investment benefits minimum mandated in the CLCPA. This EAM is also aligned with CLCPA’s goals of achieving an 85% reduction in GHG emissions by 2050 and reducing 22 million tons of carbon through EE and electrification.

Q. Please describe how the Company will measure this EAM.

A. The Company will measure the Low-Income Customers & Disadvantaged Communities EAM achievement by calculating the annual non-gas device EE savings that are acquired through the Company’s LMI and non-LMI NENY EE programs. Savings acquired within Disadvantaged Communities will be counted towards Disadvantaged Community achievement.

Q. Why does the Company propose to measure annual MMBtu savings instead of lifetime savings as proposed in the STS and Deep Savings metrics?

A. It is important to drive EE savings and the associated bill savings, improvements in air quality, and improved comfort for LMI and Disadvantaged Community customers in the near term. As such, the Company proposes to measure this EAM in annual MMBtu, which will put a greater emphasis on maximizing near-term savings.

Q. Why does the Company propose to exclude gas devices from the Low-Income Customers & Disadvantaged Communities metric?

A. The Company believes a similar logic applies with gas devices to the proposed Low-Income Customers & Disadvantaged Communities metric as that discussed above for the non-LMI Gas STS metric.

Q. Why does the Company propose to include residential lighting savings for this metric but not the Electric STS metric?

A. The Company proposes to include residential lighting savings in the Low-Income Customers & Disadvantaged Communities metric because it believes lighting measures are not a mature EE upgrade for LMI customers and lighting upgrades are a meaningful way to drive bill reductions for these customers. Many LMI customers are renters and do not have ownership or control over many of the in-unit appliances that contribute to their energy bills, limiting the range of EE upgrades they can make. In addition to the greater control offered by LED lighting, it is one of the few measures that renters can continue to benefit from when moving to a new house or apartment. Customers can take their LEDs with them unlike refrigerators, for example, which typically are the property of the building owner.

Q. How will the Company calculate the baseline for this EAM?

A. The baseline will come from the Company’s SEEP filing. For the LMI baseline, Company proposes to remove expected gas device efficiency savings. The Company has also proposed a scaling formula in Exhibit __ (CES-9) for the Low Income & Disadvantaged Community metric to account for changes to NENY targets and budgets as the result of the upcoming interim review or other Commission action in the NENY proceeding.

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. The minimum, midpoint, and maximum targets for this EAM are based on overachieving the baseline by 5%, 10%, and 20% respectively for each Rate Year with basis points of 3, 6, and 10 allocated to each of the targets, respectively.

Q. How does the proposed Low Income & Disadvantaged Community metric interact with the STS metrics and Deep Savings?

A. The LMI EE savings are distinct from the STS metrics as LMI savings do not count towards those metrics. The Disadvantaged Community savings portion of the metric is intended to complement the STS and Deep Savings metrics by sending a clear signal to exceed 35% of investment going to Disadvantaged Communities. The STS and Deep Savings metrics drive overachievement of goals, cost reductions, and push the portfolio to more challenging sources of savings but do not explicitly influence the geographic targeting of savings to overachieve the 35% of benefits of investment goal. The Disadvantaged Community savings portion of the Low Income & Disadvantaged Community metric intends to fill this gap.

Q. Why does the Company propose to set targets off its SEEP as opposed to its ordered NENY targets for the Electric STS, Gas STS, Deep Savings, and Low Income & Disadvantaged Community EAM metrics?

A. The Company is overachieving its NENY targets and is pulling NENY authorized investment forward to fund overachievement. The Company plans to achieve all its cumulative 6-year NENY targets but on a schedule that is, in several cases, in advance of NENY. As a result, the Company proposes to set targets based off the more aggressive NENY period achievement in its December 2021 SEEP filing which it believes are a more accurate forecast of its expected savings over the rate period. The Company proposes to formulaically adjust targets based on the outcome of NENY interim review or other Commission action in the NENY proceeding. For example, given the accomplishments in Clean Heat discussed earlier in this testimony, the Company will request in the NENY proceeding additional funding authorization with increased Clean Heat savings goals.

v. Demand Response

Q. Please describe the goal of the Demand Response EAM and how it aligns with policy objectives.

A. The DR metric is intended to drive significant participation from smaller customers in pay-for-participation DR programs (CSRP and Term-DLM) beyond the programs’ expected organic growth. This EAM promotes grid flexibility in support of CLCPA’s goal to achieve 100% clean energy by 2040 by developing a larger and more reliable Demand Response resource that the Company can call on to reduce network peak demand and during network contingencies.

Q. Please explain why the Company proposes to introduce a DR EAM.

A. The Company proposes this EAM to achieve greater growth in small customer participation, a largely untapped customer segment. Prior to the deployment of AMI, customers with less than 500 kW peak demand had to pay for communicating interval meters that are required to enroll in the Company's DR program. This requirement hindered small customers from participating in the DR programs because few customers proactively made this investment. AMI deployment has newly expanded DR eligibility to all customers segments, but most small commercial and residential customers are not yet engaged with the DR program. Given the opportunity for growth in customer participation AMI has unlocked, the Company proposes this EAM to accelerate small customer enrollment beyond organic growth.

Q. Please describe how the Company will measure this EAM.

A. The Company will measure the DR EAM by using DRMS data to report customer count in a similar manner to the DR Annual Report. This metric will measure a segment of the total number of DR participants. The metric will take the number of SC1 and SC2 customers enrolled that achieved a performance factor of at least 25% in at least one event. This methodology will count customers who not only enroll but also provide positive load relief reductions.

Q. Why was a performance factor of greater than 25% selected as the threshold for measurement of the EAM?

A. The Company sought to establish a minimum threshold to verify the customers are providing demand reduction but avoid adverse impacts from customers unfamiliar with demand response potentially misjudging their enrollment (participating in DR will be a new way of engaging with energy for many smaller customers, likely requiring time to calibrate their enrollment and interest in the programs). 25% is the minimum performance required for an Aggregator to receive a Reservation Payment as outlined in the Electric Tariff. As a result, the Company proposes to use 25% for this purpose as well.

Q. How will the Company calculate the baseline for this EAM?

A. The baseline for the DR EAM will be calculated by growing the previous year's performance. For example, in 2023, the baseline for the EAM will be the actual number of SC1 and SC2 participants in 2022 that achieved the minimum performance requirement multiplied by a growth factor of 1.7. For each subsequent rate year, the baseline will be determined by multiplying the actual number of SC1 and SC2 participants that met the performance criteria from the previous year by the growth factor. Please see Exhibit __ (CES-9) for the baseline formula.

The Company calculated the growth factor based on the performance of Commonwealth Edison Company's ("Com Ed") Peak Time Savings Program from 2015 through 2020.[38] The Company proposes to use Com Ed's program as a reference because Com Ed deployed AMI on a widespread basis earlier than the Company, thereby enabling its customers access to peak time savings incentives during the 2015 to 2020 period.

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. The minimum, midpoint, and maximum targets for the DR EAM were set at multiples of 2, 6, and 10 times the baseline growth forecasted for the DR program, with 1, 3, and 5 basis

38 ICC Docket No. 12-0484, Petition for Approval of Tariffs Implementing ComEd's Proposed Peak Time Rebate Program, Commonwealth Edison Company's Peak Time Savings Program Annual Reports from 2015 through 2020. *See*, https://www.icc.illinois.gov/docket/P2012-0484/documents.

points respectively allocated to the targets. By linking this EAM to the goal of significant participation in DR, these percentages create a signal to the Company to expand its DR program beyond the expected organic growth levels. This growth will bring in additional resources and benefits to the grid and increase customer awareness of their own energy use.

vi. Transportation Electrification

Q. Please describe the goal of the Transportation Electrification metric and how it aligns with policy objectives.

A. The Transportation Electrification EAM encourages the Company to support customers in their transition to electric transportation using all tools available to achieve this outcome. It aligns with CLCPA’s goal to drive an 85%

reduction in GHG emissions by 2050 as well as Commission objectives established in the EV proceeding.[39]

Q. Please explain how the Transportation Electrification EAM is connected to the Company's Beneficial Electrification EAM in the 2020–2022 Rate Period.

A. In the 2020–2022 Rate Period, the Company has a Beneficial Electrification EAM that measures lifetime CO_2 emission reductions from heat pump installations and electric vehicles purchased in the Company's service territory. The Company proposes to incentivize overachievement of NENY's heat pump targets through the Deep Savings EAM proposed above and discontinue Beneficial Electrification's heat pump component to avoid duplicative EAMs. The Company proposes to retain the electric vehicle portion of Beneficial

39 Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure* (EVSE&I Proceeding), Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020).

Electrification EAM here but rename the EAM Transportation Electrification, given the narrower scope of the EAM.

Q. How will the Company measure this EAM?

A. The Company will measure the Transportation Electrification EAM by lifetime tons of CO_2 emission reductions. CO_2 reductions are calculated in two steps. First, the number of newly registered EVs within the service territory will be determined using the Atlas EVaulateNY[40] tool to determine the count of new light-duty EVs. The number of new medium- and heavy-duty vehicles will be determined using Con Edison’s own internal tracker. The Company will convert the number of light, medium, and heavy duty EVs into lifetime tons of CO_2 savings through conversion factors that reflect the total amount of lifetime tons of avoided carbon associated with the increase in the number of each type of electric vehicle. Please see Exhibit __ (CES-9) for details.

[40] *See*, https://atlaspolicy.com/evaluateny/

Q. How will the Company calculate the baseline for this EAM, including data sources the Company will use for baseline development?

A. The baseline for the Transportation Electrification EAM is calculated using the Electric Power Research Institute ("EPRI") light duty EV 2022-2030 forecast for light duty vehicles, and transit electrification announcements for medium and heavy-duty vehicles. EPRI's light duty vehicle forecast for newly registered battery electric vehicles ("BEV") and plug-in hybrid electric vehicles ("PHEV") in the Con Edison territory will serve as the vehicle baseline for light duty electric vehicles. The number of newly registered BEV and PHEV will be converted to the EAM CO_2 reduction baseline through multiplication by a CO_2 conversion factor. The CO_2 conversion factor is calculated by taking the product of a CO_2 emissions rate per mile traveled and the estimated net vehicle miles traveled, separately for BEV and PHEV. The BTU/gallon of gasoline factor is sourced from the Alternative Fuels Data Center (AFDC), and the vehicle miles traveled are estimated based on EPRI, and together they capture kg of CO_2 savings by vehicle type (BEV or PHEV).

With medium and heavy-duty vehicle activity relatively limited within the Company's service territory and with few entities having announced concrete electrification plans, the Company utilized public fleet announcements from the private sector, such as the Metropolitan Transportation Authority and Westchester's Bee-line, to capture planned growth of the medium and heavy-duty sector. The projected EVs newly registered will serve as the vehicle baseline and will be converted to the EAM baseline through the CO_2 conversion factor, adjusting for the different vehicle types. Vehicle class will be determined based on the Alternative Fuels Data Center weight class classification (https://afdc.energy.gov/data/10380).

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. The minimum, midpoint, and maximum targets for the Transportation Electrification EAM were set at 5%, 20%, and 35% above the baseline lifetime ton CO_2 emission reduction with basis points of 2, 4, and 7 allocated to each of the targets, respectively.

Q. How does the Transportation Electrification EAM interact with the Company’s Share the Savings metric under the Commission-authorized EV Make Ready Program[41] authorized in the state’s EV proceeding?

A. The Transportation Electrification EAM focuses on the CO_2 reductions achieved through adoption of electric vehicles, while the Make Ready Share the Savings EAM incentivizes the Company to support installation of EV chargers cost efficiently. Although access to EV charging, such as those charging plugs installed under the Make Ready program, does support EV adoption, there are many factors that influence the decision to purchase an electric vehicle and these two metrics are relatively independent.

[41] Case 18-E-0138, *Proceeding on Motion of the Commission Regarding Electric Vehicle Supply Equipment and Infrastructure*, Order Establishing Electric Vehicle Infrastructure Make-Ready Program and Other Programs (issued July 16, 2020).

vii. CVO

Q. Please describe the Conservation Voltage Optimization (CVO) program, the goal of the CVO metric and how it is aligned with policy objectives.

A. The CVO program is described earlier in this testimony. The CVO EAM is designed to encourage the Company to achieve energy savings beyond the targets set in its capital funding proposal that was described earlier in this testimony. This EAM is aligned with CLCPA's goal to drive an 85% reduction in GHG emissions by 2050.

Q. Please describe how the savings targeted by this EAM are incremental to the savings generated by the proposed CVO efforts described above as part of the Company's Smart Grid Optimization plan?

A. CVO reduces energy usage across the Company's service territory, thereby decreasing associated fuel use for committed generation resources and CO_2 emissions. In addition, CVO lowers customer bills because electrical appliances consume less electricity when operated at a reduced voltage. As part of the Smart Grid Optimization plan, the Company is proposing reinforcement work to accelerate the CVO schedule and increase the total system energy savings from 1.5 to 1.75 percent by 2025, helping reduce energy supply costs for customers and reduce greenhouse gas emissions. The CVO EAM sets targets above the savings resulting from the capital improvements. To achieve additional energy savings the Company will need to further optimize how it identifies areas requiring reinforcement work, identify and innovate around ways to automate CVO implementation where possible, and develop creative solutions to remove voltage limitations in area stations.

Q. How will the Company measure this EAM?

A. The CVO EAM will be measured in terms of annual percent of realized energy savings, calculated from the voltage reduction multiplied by a CVO factor. The Company will use CVO factors based on a combination of performed M&V studies and industry average CVO factors that have previously been discussed with DPS Staff. The Company utilizes an analytics platform to receive the SCADA data from each station along with the voltage optimization settings to calculate the overall energy savings of the entire service territory. The analytics platform determines the average hourly energy savings utilizing the different settings along with the proportional capability of each station and the associated CVO factor. The energy savings data is then aggregated into monthly and yearly energy savings.

Q. How will the Company calculate the baseline for this EAM?

A. The energy savings from the capital project will serve as the baseline for the CVO EAM.

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. The minimum, midpoint, and maximum targets for the CVO EAM were set at 2%, 5%, and 8% above the CVO energy savings expected from the proposed capital project, and the basis points associated with these targets are 3, 6, and 10 respectively.

viii. DER Utilization

Q. Please describe the goal of the DER Utilization metric and how it is aligned with policy objectives.

A. The DER Utilization EAM incentivizes the Company to support customer adoption of solar and battery storage technologies above market trends. This metric aligns with CLCPA's goal to interconnect 6,000 MWs of battery storage by 2030 and 6,000 MWs of solar by 2025.

Q. Please describe how the Company will measure this EAM.

A. The Company proposes to generally retain the DER Utilization metric currently in place with modifications and measure it by the annualized MWh produced, consumed, or discharged by applicable DER technologies that are interconnected each Rate Year. See Exhibit __ (CES-9).

Q. What changes are proposed for this EAM?

A. The Company is proposing to: (1) streamline this EAM by narrowing the EAM to just solar and battery storage technologies, and (2) develop separate, formulaic targets for the solar and battery storage.

Q. Why does the Company propose to narrow the EAM to solar and battery storage?

A. The Company proposes to eliminate ice storage and distributed wind resources from the metric as there have been no installations of wind in the service territory for at least the last couple of years, and the Company does not have insight into the level of ice storage activity since the end of the ice storage incentive program in 2019. Ice storage installations were a de minimis contributor to DER Utilization achievement in 2017–2019, while the Company offered incentives for the technology. The Company believes it should focus its activity on supporting solar and battery storage development and therefore the Company proposes to measure this activity only.

Q. Please explain the proposed modifications related to solar and storage.

A. The Company proposes to establish two separate targets and basis point allocations, one each for solar and energy storage systems. The Company proposes to set solar and energy storage targets formulaically on a rolling annual basis to account for changing market dynamics. The Company proposes the same formulaic approach for solar and energy storage based on a trendline methodology reflecting the four-year period prior to the corresponding EAM year. Please see Exhibit __ (CES-9) for the formula.

Q. Why is the Company recommending separate EAMs for solar and storage with a formula to adjust the metric targets over time?

A. The Company proposes to separate solar and energy storage within the DER Utilization metric to better tailor targets to the respective technologies. The solar and energy storage markets in the Company’s service territory are still developing and face many short-term uncertainties such as: changes in local, state, and federal energy policies, pandemic-induced supply chain issues with the global Li-Ion battery supply chain. For example, this includes local Fire Department policies for storage, solar tariffs on panels made in China and evolving incentive frameworks in New York. Although these uncertainties often impact both solar and energy storage, they can do so at different times and with different impacts. As a result, the Company proposes to have separate metrics for solar and energy storage under the umbrella of DER Utilization. The signatories to the Orange and Rockland Utilities pending Joint Proposal have agreed to this approach.[42]

In addition to impacting the solar and energy storage markets differently, these uncertainties also make it difficult to establish targets over a three-year period. Therefore, the Company proposes a formulaic approach to set the solar and energy storage targets to address these market uncertainties while continuing to encourage the Company to support adoption of solar and energy storage beyond market trends.

Q. Please describe the proposed approach to setting the baselines and targets.

A. The Company proposes a trendline methodology based on the four-year period prior to the corresponding EAM year to establish future baselines and targets. Please see Exhibit

42 Case-21-E-0074, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Orange and Rockland Utilities Inc. for Electric Service*, Joint Proposal (filed October 29, 2021).

__ (CES-9) for the formula to calculate the future baselines. The Company proposes targets that are 0.5, 1.0, and 1.5 standard errors above the baseline for each technology and the basis points associated with these targets are 1, 3, and 5 respectively for each of the solar and energy storage components

ix. Electric System Peak

Q. Please describe the goal of the Electric System Peak metric and how it aligns with policy objectives.

A. The Electric System Peak EAM incentivizes the Company to reduce its actual weather normalized New York Control Area (“NYCA”) coincident system peak. By reducing the Company’s NYCA system peak coincident load, the Company can help lower the electric capacity cost for customers and reduce power sector GHG emissions as well.

Q. Please describe how the Company will measure this EAM.

A. The Company proposes to retain the Electric System Peak metric and measure it by the actual weather normalized NYCA coincident system peak for the Company's service territory as reported by NYISO Load Forecasting Task Force.

Q. Does the Company propose any changes to this EAM?

A. Yes, the Company propose a modification to the target setting formula used for this EAM. Please see Exhibit __ (CES-9) for the modified formula. The Company proposes this modification to align the Company's Electric System Peak EAM with other NYS electric utilities' Electric System Peak EAMs.

Q. Please describe how the baseline and targets are set.

A. The Company proposes to set the baseline using a modified forecast of weather normalized NYCA coincident system peak for the Company's service territory.[43] The modification to the NYISO forecast is to account for the difference between the forecast and the actual of past weather normalized NYCA coincident system peaks. Once the baseline is established,

[43] NYISO Load Forecasting Task Force provides a final forecast of the weather normalized NYCA coincident system peak for each utility in late December for the following summer system peak.

the targets are calculated as 0.25, 0.5, and 1 standard deviation of the historical difference percentage of the forecasts and actuals weather normalized NYCA coincident system peak below the baseline. The basis points associated with these targets are 3, 5 and 8 respectively. Please see Exhibit __ (CES-9) for more details of the modified formula.

Q. How does the proposed Electric System Peak EAM interact with the proposed DR EAM?

A. The Electric System Peak EAM incentivizes the Company to deliver NYCA coincident electric system peak reductions. By contrast, the Company’s DR program aims to reduce the Company’s own network peaks, which are often not coincident with the NYCA peak.

x. Gas System Footprint

Q. Please describe the goal of the Gas System Footprint EAM, and how it aligns with State policy objectives.

A. The Company’s gas system plans are consistent with the State’s CLCPA goals at this early stage of implementation. Specifically, the Company is adopting a strategy to limit new customers and overall consumption. The Company is proposing tariff changes in this rate filing that would steer new customers away from gas, such as removing financial incentives for main extensions and offering incentives for heat pumps.

Q. Does this EAM complement other existing incentive mechanisms?

A. Yes. The Gas System Footprint EAM complements the Company's Gas Safety metric, which specifies an annual abandonment goal for leak prone pipe ("LPP") in the gas distribution system. The Company can meet the Gas Safety metric with current practices while maintaining the current levels of main replacement vs. abandonment. With this EAM, however, the Company is incentivized to prioritize the installation of fewer assets, while still achieving the overall goals of the Main Replacement Program ("MRP") and meeting the Gas Safety metric.

This EAM will also complement the Company's efforts to reduce assets on the gas system through MRP Non-Pipeline Alternatives ("NPA"). Both the Footprint EAM and MRP NPA incentivize the Company to reduce the gas system footprint but do so in different ways. Under an MRP NPA, the Company would remove the need for the main by electrifying customers, while the Footprint EAM will focus on the simplification of LPP designs, where the Company does not pursue an MRP NPA. Area NPAs generally avoid new or expanded infrastructure and do not primarily focus on removing gas infrastructure and thus do not overlap with the proposed Footprint EAM.

Q. Please describe how the Company will measure this EAM.

A. The Company will measure the System Footprint EAM by dividing the annual installation footage of gas layouts with LPP abandonment by the annual LPP abandonment footage. The resulting metric will be expressed as a ratio. Leak prone pipe is defined as 12” and under cast iron and unprotected steel gas main. Any abandonment footage that the Company achieves from an NPA would be excluded from the metric.

Q. How will the Company calculate the baseline for this EAM, including data sources the Company will use for baseline development?

A. The Company calculated the baseline for the EAM by taking the ratio of the total actual installation footages from 2017-2020 associated with layouts that had LPP abandonment, divided by the total LPP abandonment footage from 2017-2020. This ratio represents the historical ratio of installed-to-replaced LPP mains. The Company used data from the Emergency Control System database for the above calculation.

Q. How would the Company calculate the minimum, midpoint, and maximum target for this EAM?

A. The Company proposes two, five, and eight percent reduction in the ratio of installed-to-abandoned LPP footage compared to the baseline number as the min, mid, and max targets respectively for the EAM. The basis points associated with these targets are 5, 15, and 25 respectively. These targets encourage the Company to overperform relative to the baseline computation described above.

xi. Gas Peak Reduction

Q. Please describe the goal of the Gas Peak Reduction EAM, and how it aligns with policy objectives.

A. The Gas Peak Reduction EAM will promote the reduction of the Company’s gas supply obligations and improve the use of infrastructure by reducing peak winter demand on the gas system. Reducing the level of gas supply and improving the utilization of the gas system infrastructure will result in lower supply costs for gas customers and potential avoidance in capital infrastructure investments respectively. Achieving peak reductions will also help to reduce GHG emissions.

Q. Please describe how the Company will measure this EAM.

A. The Company proposes to retain the Gas Peak Reduction metric and formula in the current 2020-2022 rate plan. The Gas Peak Reduction EAM sets performance targets based on a regression of four-year historical gas peak demand data, with the historic data based on the prior four winter periods preceding the Rate Year. The Gas Peak Reduction metric reflects a seasonally adjusted gas demand peak, which is expressed in terms of thousands of dekatherms per day (MDt/day) per Heating Degree Day (HDD). The Company proposes

3, 5, and 8 basis points associated with the minimum, midpoint, and maximum targets respectively.

Q. Does the Company propose any changes to this EAM?

A. No, the Company proposes to continue using the existing formula and baseline methodology for the Gas Peak EAM, as well as the same targets for each rate year in the rate period.

B. EAM Reporting and Collection

Q. How does the Company propose to report and collect EAM achievements?

A. The Company proposes to continue to report and collect EAM achievements consistent with the current rate plan provisions.

Q. How are EAMs treated for ratemaking purposes?

A. Under the currently effective rate plan, the Company files an annual EAM report on March 31 of the year following the year for which the Company has earned EAMs. Following the conclusion of a 45-day period during which DPS Staff or stakeholders can comment on the Company’s request, the Company recovers allowed EAM revenue over a 12-month period.

EAM revenue is recovered from all customers (including NYPA customers) for all EAMs except for those related to EE program performance – namely, the Share-the-Savings EE EAM and the Deeper EE EAM – which are only recovered from Con Edison customers. Revenue associated with EAMs that are recovered from NYPA customers are allocated based on the PASNY allocation.

Q. Does the Company propose to change this ratemaking approach?

A. No. The Company proposes to retain the existing ratemaking approach for EAMs, including recovering the revenues of Energy Efficiency Program EAMs (*i.e.*, Share the Savings EE EAMs, the Deep Savings EAM, and the Low-Income Customer & Disadvantage Communities EAM) from Con Edison customers only, and not from NYPA customers. The exclusion of EE may require adjustment if our NYPA allocation proposal is adopted. Please see the Rate Panels for more detail.

Q. Does this conclude the Panel’s initial testimony?

A. Yes.

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Q. Please state your name and business address.

A. My name is Yukari Saegusa. I am the Vice President and Treasurer of Consolidated Edison Company of New York, Inc. ("Con Edison" or the "Company"). I am also the Treasurer of the Company's affiliate Orange and Rockland Utilities, Inc. ("Orange and Rockland"). My business address is 4 Irving Place, New York, New York.

Q. Briefly describe your educational background.

A. I graduated from the University of Pennsylvania, Wharton School in 1989 and received a B.S. degree in Economics. I received an MBA from the MIT Sloan School of Management in 1995.

Q. Please summarize your professional background.

A. I joined Con Edison in March 2013. Prior to joining Con Edison, from 2004 to 2013 I was employed by Barclays as a Managing Director in Debt Capital Markets covering the United States utility and energy sectors. I was employed from 1995 to 2004 by Citigroup, also in Debt Capital Markets covering the United States utility sector. In my roles at Barclays and Citigroup, I was broadly responsible for advising utility clients on the design and execution of debt, capital-raising, and liability management strategies.

Q. Have you previously sponsored testimony before the New York State Public Service Commission ("Commission")?

A. Yes. I submitted testimony on behalf of Con Edison in Cases 19-E-0065 and 19-G-0066 and on behalf of Orange and Rockland in Cases 14-E-0493, 14-G-0494, 18-E-0067, 18-G-0068, 21-G-0073 and 21-E-0074.

Q. What is the purpose of your direct testimony in these proceedings?

A. My direct testimony discusses (1) the current financial market environment, (2) the Company's historic and projected capital structure and cost of capital, and (3) the Company's financial challenges and the need to maintain access to financial markets at reasonable cost.

I. CURRENT FINANCIAL MARKET ENVIRONMENT

Q. Please describe the current state of the financial markets.

A. Prior to the beginning of the COVID-19 pandemic, the U.S. experienced a historic ten-year period of economic expansion. U.S gross domestic product grew at an annual rate of 2.1% in the fourth quarter of 2019 and the unemployment rate had dropped from a high of 10.0% in October 2009 to 3.6% in December 2019. Currently, however, the economy is in the midst of recovering from a severe economic retraction and extreme volatility caused by the unprecedented and disruptive economic impacts of the COVID-19 pandemic.

Q. Can you provide some examples of COVID-19 pandemic related economic impacts and volatility?

A. Some of the major economic impacts include U.S. gross domestic product falling at an annual rate of 31.4% in the second quarter of 2020 before rising again by 33.8% in the third quarter of 2020; the unemployment rate rising from a low of 3.5% in February 2020 to a peak of 14.7% in April 2020 before falling back to 4.2% in November 2021; and a seasonally adjusted drop in industrial production of 12.7% in April 2020 before recovering back close to pre-pandemic levels in August 2021.

Q. How has the COVID-19 pandemic specifically impacted the economy of New York State?

A. In order to slow the rate of COVID-19 infections in the State, former Governor Cuomo on March 22, 2020 implemented the “New York State on PAUSE” executive order which, among other restrictions on social gatherings, ordered all non-essential businesses to shut down until a series of health monitoring statistics showed sufficient improvement. As a result, according to the State Comptroller's Office, New York State's job count fell by over 1.9 million people in March and April 2020, of which only 600,000 had regained employment by September 2020. Businesses were allowed to slowly reopen through the summer and fall of 2020 as health statistics showed continuing improvement, but limitations continued regarding how many people could gather together in one place and under what conditions they could be together. Restrictions were briefly lifted in the summer and fall of 2021, but concern with new variants prompted Governor Kathy Hochul to declare another State of Emergency on November 26, 2021.

Q. Has the Company felt any negative economic impacts related to the COVID-19 pandemic?

A. Yes. In March 2020, Con Edison began suspending utility service disconnections, certain collection notices, final bill collection agency activity, new late payment charges and certain other fees for all customers. In June 2020, the State of New York enacted the Parker Mosely Act which prohibited utilities from disconnecting residential customers during the COVID-19 state of emergency.

Subsequent legislation extended protections to certain small commercial customers. As a result, the Company's accounts receivable balance has grown significantly with October 2021 residential arrearages over 60 days increasing to $768 million and non-residential arrearages over 60 days increasing to $408 million compared to 2019 baselines of approximately $325 million and $85 million, respectively.

Q. Has the Company been allowed to recover any of these items?

A. Yes, on November 18, 2021 the Commission issued an order authorizing a surcharge mechanism for recovery of unbilled late payment charges and fees.

Q. Has the pandemic also been disruptive to the capital markets?

A. Yes. The U.S. equity market has experienced much higher volatility due to the pandemic as compared to prior years. The VIX index, which measures volatility in the equity market, hit an all-time high of 82.7 on March 16, 2020 and has averaged 26.0 since March 1, 2020 as compared to an average of 17.3 over the past ten years.

Q. What has been the impact of the pandemic on the fixed income markets?

A. Overall, the U.S. fixed income market is now in its third decade of a bull market run. Investors have been willing to invest money at record low yields as they look to put funds to work in an artificially low interest rate environment. The yield on Moody's Baa Corporate Bond Index recently stood at 3.35% (October 15, 2021) compared to a long-term average of 7.09% since January 2, 1986. The drive to record low yields began with unprecedented actions taken by the U.S. Federal Reserve and central banks around the world in response to the 2008 financial crisis. The Federal Reserve and other central banks have injected substantial amounts of liquidity into their respective economies through multiple rounds of quantitative easing.

Q. What do you mean by quantitative easing?

A. Quantitative easing is the practice of using money, newly issued by the central banks, to buy mortgage-backed and government securities. The practice increases liquidity by injecting money supply into the economy and suppressing interest rates by driving the prices of the mortgage-backed and government securities up and yields on those securities down.

Q. Did the Federal Reserve take action to scale back the unprecedented actions it took after the 2008 financial crisis?

A. Yes, but only temporarily. Starting in January 2014, the Federal Reserve gradually began to reduce the amount of its bond purchases, ending them completely in October 2014, and signaling an end to its loose monetary policy. In the December 2015 meeting of the Federal Open Markets Committee ("FOMC"), the Federal Reserve raised the Federal Funds rate by 25 basis points ("bps"), further signaling the end of an easing cycle and the beginning of a hiking cycle. The Federal Funds rate is the interest rate at which a depository institution lends funds maintained at the Federal Reserve to another depository institution overnight. The Federal Funds rate is one of the most influential interest rates in the U.S. economy because it affects monetary and financial conditions, which in turn have a bearing on key aspects of the economy including employment, growth and inflation. After the December 2015 Federal Funds rate increase, the FOMC raised the Federal Funds rate eight times (at the December 2016, March 2017, June 2017, December 2017, March 2018, June 2018, September 2018 and December 2018 meetings) before it reversed course and lowered rates three times (at the August 2019, September 2019 and October 2019 meetings).

Q. Has the COVID-19 pandemic caused the Federal Reserve to make any further adjustments to the Federal Funds rate?

A. Yes. The onset of the pandemic caused large disruptions in liquidity and borrowing rates. A2/P2 rated commercial paper, which had generally been trending with Federal Funds rate increases and decreases, saw increases of up to 225 basis points between the low and high points of March 2020 (see Exhibit_(YS-1)). At the same time, longer-term liquidity in the commercial paper market shrank with one- to four-day commercial paper spiking up to over 85% of total issuance in mid-March from pre-COVID levels that varied around 60% (see Exhibit_(YS-2)). After the experience of the 2008 financial crisis, the Federal Reserve was highly aware that supporting the functioning of the funding markets was critical and acted quickly to support the commercial paper markets. Over the course of two meetings (March 3, 2020 and March 16, 2020) the Federal Reserve responded forcefully to increase liquidity by cutting the Federal Funds rate by an unprecedented 150 basis points to a record low target range of 0.00%-0.25% where it remains today.

Q. Did these reductions in rates impact the commercial paper market?

A. Yes. Since the peak in March, A2/P2 rated commercial paper rates have decreased to be in line with the current Federal Funds target and the percentage of 1- to 4-day commercial paper has decreased back closer to pre-COVID-19 pandemic levels as longer-term funding became more available.

Q. Did the Federal Reserve take any other actions to support credit in response to the COVID-19 pandemic?

A. Yes. In an effort to limit the economic damage caused by the pandemic, the Federal Reserve took other actions to increase liquidity and manage interest rates. Chief among them were:

- the announcement of $700 billion for a new round of quantitative easing (Federal Reserve Press Release, March 15, 2020);
- Commercial Paper Funding Facility (“CPFF”) to support up to $1 trillion of liquidity in the corporate paper markets as well as the Primary Dealer Credit Facility (“PDCF”), which offers collateralized loans to large broker-dealers (Federal Reserve Press Release, March 17, 2020);

- Money Market Mutual Fund Liquidity Facility (“MMLF”) offering collateralized loans to large banks buying assets from money market mutual funds (Federal Reserve Press Release, March 18, 2020); and
- The establishment of three new emergency lending facilities - the Primary Market Corporate Credit Facility (“PMCCF”), the Secondary Market Corporate Credit Facility (“SMCCF”) and the Term Asset-Backed Securities Loan Facility (“TALF”) (Federal Reserve Press Release, March 23, 2020).

The U.S. government also stepped in to provide economic stimulus by passing the $2.1 trillion Coronavirus Aid, Relief, and Economic Security (“CARES”) Act to support individuals, businesses, governments and healthcare providers impacted by the COVID-19 pandemic, and also the Paycheck Protection Program and the Health Care Enhancement Act, which provided an additional $484 billion in emergency aid.

Q. What was the result of intervention from the Federal Reserve and U.S. Government?

A. These programs increased liquidity and helped stabilize the commercial paper markets by increasing the ability for borrowers to access the commercial paper market more efficiently.

Q. Has the Federal Reserve given projections on how long the Federal Funds target will be held at these levels?

A. Yes. The Federal Reserve publishes a forecast of the Federal Funds rate for 2022, 2023, 2024 and longer run. The projections are based on the individual assessments of the Federal Reserve Board members and Federal Reserve Bank presidents. In the latest forecast (December 2021), the median of the FOMC participants' assessments of appropriate monetary policy forecasts the Federal Funds rate to increase to 0.9% in 2022, 1.6% in 2023 and 2.1% in 2024.

Q. Does the forecasted rise in the Federal Funds rate correlate to a rise in short-term borrowing rates?

A. Yes. As mentioned earlier, changes in commercial paper rates track very closely with changes in the Federal Funds rate.

Q. Do changes in the Federal Funds rate also track with changes in longer-term borrowing rates?

A. Yes, but another important factor impacting longer-term borrowing rates is inflation. While the Federal Reserve continues to target an average inflation rate of 2%, it has indicated a willingness to allow inflation to moderately exceed 2% for some time.

Q. Has inflation exceeded the 2% target?

A. Yes. Inflation, as measured by changes in Personal Consumption Expenditures (“PCE”), has been steadily increasing for the past ten months. For the period ended September 2021, the PCE has had a 12-month average increase of 2.8% and has exceeded 4.0% in each of the last five months to reach a 30-year high of 4.4% in September 2021.

Q. Is PCE the only measure of inflation?

A. No, there are other measures of inflation. One of the most common is the Consumer Price Index (“CPI”) which measures the average monthly change in the price for goods and services paid by urban consumers.

Q. Has the CPI also shown higher levels of inflation in recent months?

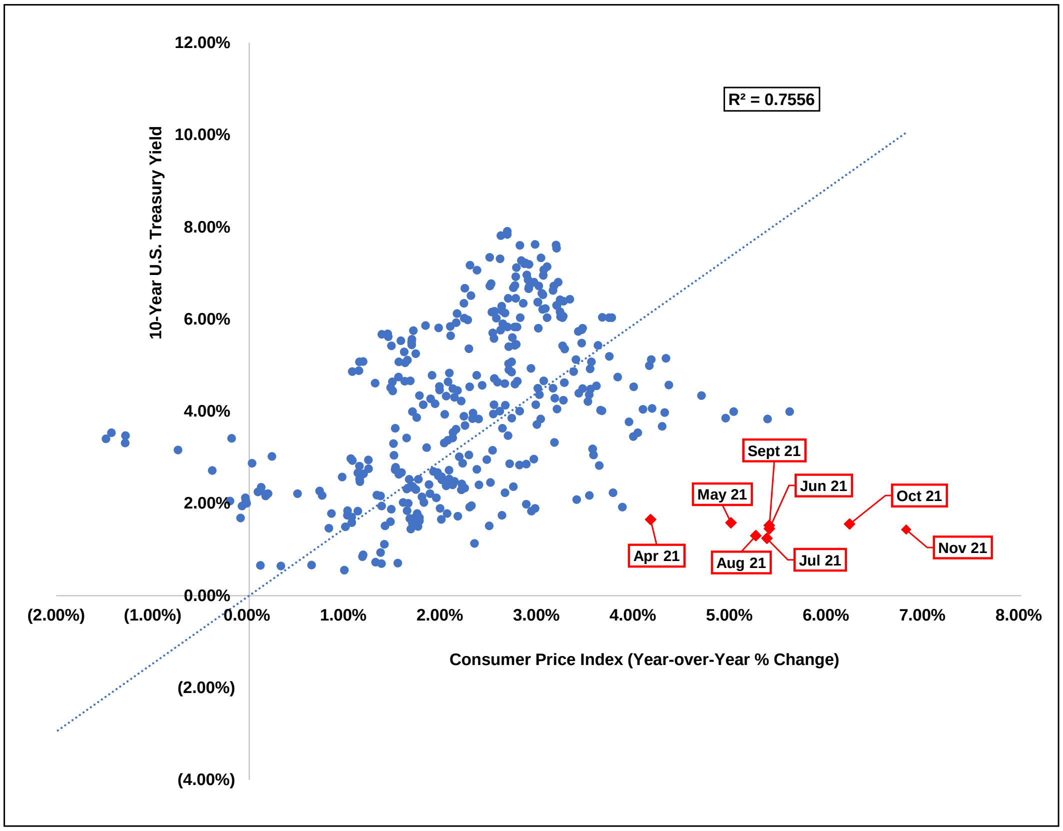
A. Yes. The CPI has risen from 0.2% in May 2021 to 6.8% in November 2021, a level not seen since June 1982 (see Exhibit__(YS-3)).

Q. What is the correlation between inflation and longer-term borrowing rates?

A. A large component of long-term borrowing rates is Treasury rates. Treasury rates are sensitive to both actual and forecasted inflation rates. Higher inflation rates drive higher Treasury rates and correspondingly drive higher longer-term borrowing rates.

Q. Have you examined the historical relationship between the rate of inflation and U.S. Treasury rates?

A. Yes. In the scatter plot below, we charted the monthly, year-over-year percentage change of the U.S. CPI (as the independent variable) against the 10-year U.S. Treasury yield (as the dependent variable) over the last 20 years. This plot confirms that, over the past 20 years, there has been a strong positive correlation between the rate of inflation and U.S. Treasury yields as evidenced by the coefficient of determination or R-squared of 0.76. It is reasonable to expect that as inflation increases, the yield investors would demand on U.S. Treasury securities will also increase.



Source: Bureau of Labor Statistics and U.S. Dept. of Treasury

Q. What additional conclusions, if any, can be drawn from the scatter plot?

A. The scatter plot highlights a number of data points of interest in red. These data points mark selected outliers in the data. These outliers represent times when the observed U.S. Treasury yield did not match the level implied by the corresponding rate of inflation. It is interesting to note that these outliers all occurred in 2021.

Q. What are potential reasons why 2021 has produced this number of outliers in the data?

A. First, as discussed earlier, the Federal Reserve is intervening in the fixed income market to keep interest rates artificially low. Second, the Federal Reserve's earlier expectations of inflation have turned out to be incorrect. At the April 2021 FOMC meeting, the Federal Reserve's press release stated:

> *Inflation has risen, largely reflecting transitory factors.*

Federal Reserve Chair Powell further added:

> *An episode of one-time price increases as the economy reopens is not likely to lead to persistent year-over-year inflation into the future.*

But, over the past few month as inflation continues to rise, the Federal Reserve has begun to acknowledge that their initial expectations for inflation were wrong. When Federal Reserve Chair Powell was asked, at a congressional hearing in early December 2021, if he thought that price increases were not particularly large or persistent, he said:

No, that is no longer my view.

Q. What implication could this change in the Federal Reserve's view on inflation have on interest rates?

A. The primary implication is that the Federal Reserve's error in initially viewing inflation as transitory has caused it to delay reducing monetary stimulus and raising interest rates to combat rising inflation. If inflation continues to remain high, the Federal Reserve may be forced to act more forcefully. In fact, in its December FOMC meeting, the Federal Reserve announced that beginning in January 2022 it would increase the pace of tapering of its bond buying program by buying $60 billion of bonds each month starting in January, half the level prior to the November taper and $30 billion less than it had been buying in December. The Federal Reserve further announced that "similar reductions in the pace of net asset purchases will likely be appropriate each month". Additionally, a majority of the FOMC members indicated that up to three 25 bps increases in the Federal Funds rate may be required in 2022, with 12 of the 18 members signaling that a target rate of at least 0.875% would be appropriate.

Q. Is inflation expected to continue above the Federal Reserve’s target of 2.0%?

A. Yes. Multiple sources project the inflation rate to remain elevated above the Federal Reserve’s target of 2.0% at least through the end of 2022 and into 2023. The November 2021 Blue Chip Financial Forecast has both the CPI and PCE indices decreasing from their current highs, but remaining above 2.0% through the forecast period ended Q1 2023 (see Exhibit__(YS-4)).

Q. Could inflation continue at a rate higher than 2.0% after Q1 2023?

A. It is highly possible. Two factors currently impacting inflation are historically high government spending and historically low interest rates and while the Fed has recently started to talk about the potential need to raise rates in 2022, the high level of government spending shows no indication of ending in the near future. Since May 2020 the Federal government has passed COVID-19 relief stimulus packages totaling $5.8 trillion. Additionally, in November 2021, the $1.2 trillion

Infrastructure Investment and Jobs Act was signed into law and Congress is considering whether to enact additional spending legislation, such as the Build Back Better Act.

Q. Do the Federal Reserve Board members expect inflation to remain above 2.0% over the next several years?

A. Yes. In their December 2021 economic projections, the median of the Federal Reserve Board members' expectation of PCE inflation was 2.6% in 2022, 2.3% in 2023 and 2.1% in 2024.

Q. Has the Company proposed a method to mitigate risks of inflation on interest rates?

A. Yes. The Accounting Panel testimony describes a proposal to reconcile the effects of inflation to the extent that actual inflation exceeds 5.0% in any of the rate years and the Company's electric or gas earnings are less than the authorized ROE applicable to that rate year.

Q. Is inflation the only factor in today's financial markets that could significantly impact the Company's cost of capital?

A. No, volatility in the financial markets has been and will continue to be one of the Company's most significant challenges as the Company continually needs to access the capital markets. Global events like the COVID-19 pandemic have the potential to further increase volatility in the capital markets. Other impactful geopolitical events (e.g., trade tensions between the U.S. and China, unrest surrounding the U.S. political environment, and the ongoing threat of a shutdown of the Federal government) can also produce shocks that could affect the Company's ability to access capital markets efficiently.

Q. How will the possibility of rising interest rates in a potentially volatile market impact the Company?

A. Taking the aforementioned factors into account, one of the main challenges faced by the Company is its ability to earn a fair rate of return. A confluence of factors, including the regulatory approach in New York to setting cost rates for debt and equity and a rising interest rate environment, expose the Company to the risk that it will not be able to earn its cost of capital. This will make the Company less attractive to both equity and debt investors which, in turn, could increase the costs of financing.

Q. Is there evidence that these factors have already impacted the Company's attractiveness to investors?

A. Yes. Equity investors have historically given the Company a lower valuation than its peer groups. When compared to other companies in the S&P 500, Con Edison, Inc.'s ("CEI") five-year average price to book ratio ranks in the bottom quartile. Also, CEI's level of positive equity analyst recommendations ranked 503 out of the 505 S&P 500 members that have rankings available.

Q. Please describe the shortcomings of New York's approach to setting cost rates for debt in the current financial market environment?

A. The Department of Public Service Staff ("Staff") sets cost rates for fixed debt based only on current interest rates, which ignores the risk of rising rates as the Federal Reserve continues to aim for higher sustained inflation targets. In addition, rates have exhibited volatility in relation to recent economic uncertainty. Since the beginning of 2020, there have been close to 140 basis point swings between the high and low yields for both 10-year and 30-year Treasury bonds. A rise in volatility would likely lead investors to require a higher rate of return to compensate them for the additional risks that they will have to bear given this increased volatility.

Q. Has the Company proposed a method to mitigate risks of interest rate volatility?

A. Yes. As described in more detail in Section II of this testimony, the primary method to mitigate the risks of future interest rate volatility is to use a forward looking method to forecast interest rates rather than using only current rates as a proxy. However, since Staff has historically not accepted this forecast methodology, the Accounting Panel testimony describes a proposal, similar to the existing true-up of the weighted average cost of variable debt, to true up the weighted average cost of long term debt to the fixed debt cost rates reflected in Exhibit AP-5

Q. Please describe the shortcomings with Staff's approach to setting cost rates for equity in the current financial market environment.

A. The current low interest rate environment has pushed utility equity market valuations above historical levels. These conditions are exacerbating the flaws of Staff's reliance on a formulaic approach to determining a fair return on equity ("ROE"). Staff's discounted cash flow ("DCF") model, in particular, is producing results that are well below historical levels.

II. CAPITALIZATION AND COST OF CAPITAL

Q. What capital structure should be used in the context of these rate case proceedings?

A. A capital structure with a 50.00% equity ratio, 0.89% customer deposits ratio and a 49.11% debt ratio should be used.

Q. Please describe why this proposed capital structure is appropriate.

A. The proposed capital structure with a 50.00% equity ratio (as compared with the 48.00% equity ratio in the Company's current electric and gas rate plans) is appropriate and necessary to address the Company's weaker cash flow profile. The Company's weaker cash flow profile is a direct result of the continued low ROE and equity ratios in its recent rate plans.

Q. Have there been other factors that have contributed to the Company's weaker cash flows?

A. Yes. The passage of the Tax Cut and Jobs Act of 2017 ("TCJA"), the COVID-19 pandemic, and the impact from Tropical Storm Isaias, have all recently contributed to the Company's weaker cash flows.

Q. What impact did the TCJA have on the Company’s cash flows?

A. The passage of the TCJA in 2017 exacerbated the Company’s already weak cash flows. The reduction of the maximum corporate tax rate from 35% to 21% and the curtailment of bonus depreciation required the Company to return a total of $2,823 million to electric customers ($377 million over 3 years, $784 million over 5 years and $1,663 million over the remaining lives of the related assets) and $895 million to gas customers from 2020 onward ($63 million over 2 years, $107 million over 5 years and $725 million over the remaining lives of the related assets), negatively affecting its cash flow.

Q. What impact has the COVID-19 pandemic had on the Company’s cash flows?

A. In March 2020, the Company began suspending service disconnections, certain collection notices, final bill collection agency activity, new late payment charges and certain other fees for all customers. The Company also began providing payment extensions for all customers that were scheduled to be disconnected prior to the start of the COVID-19 pandemic. In June 2020, the State of New York enacted a law prohibiting New York utilities, including Con Edison, from disconnecting residential customers during the first COVID-19 pandemic state of emergency. Subsequent legislation extended protections to certain small commercial customers during the first state of emergency. The Company had foregone an estimated $124 million of revenue in late payment charges and other fees and increased its uncollectible account reserve by $198 million due to these actions. Although recovery has recently begun for the unbilled 2020 late payment fees, the delay in recovery put cash flow pressure on the Company.

Q. What impact did Tropical Storm Isaias have on the Company's cash flows?

A. Con Edison incurred costs for Tropical Storm Isaias of $153 million, including $77 million of incremental operation and maintenance costs. Delay in recovery of expenses incurred under severe storms like Tropical Storm Isaias puts the Company at a cash flow disadvantage. As storm events continue to increase in both frequency and intensity, they will continue to erode the cash position of the Company.

Q. Has the Company proposed measures to recover large storm expenses?

A. Yes. In the Accounting Panel testimony, the Company proposes a surcharge for actual major storm costs that vary from the rate allowance by more than $7 million in a given rate year. Once the $7 million variance is triggered, the Company would be allowed to recover through a surcharge the entire variance up to 2.5% of delivery revenues each year.

Q. Why are strong cash flows important?

A. Cash flow is a critical component of the quantitative side of the credit analysis used in determining the Company's credit ratings.

Q. Please describe the importance of credit ratings to the Company's customers

A. Credit ratings can directly affect the cost of capital, with lower credit ratings increasing the cost of capital which will ultimately be borne by customers.

Q. Have the Company's low cash flows impacted its credit ratings?

A. Yes. The chart below shows the decline in Con Edison's Moody's and S&P credit ratings over the past five years from A2 Stable/A1 Stable in 2015 to Baa1 Stable/A1 Negative in 2020. The declines in the cash flow metrics used by Moody's and S&P track with the downgrades in both rating and outlook and also track with the declines in allowed ROE.

		Credit Ratings			
		Moody's		S&P	
	Allowed ROE	(CFO Pre-W/C)/Debt	Rating	FFO/Debt	Rating
2016	9.20%	21.3%	A2 Stable	22.5%	A1 Stable
2017	9.00%	19.0%	A2 Stable	20.2%	A1 Stable
2018	9.00%	17.6%	A3 Stable	17.5%	A1 Stable
2019	9.00%	13.9%	A3 Negative	17.9%	A1 Stable
2020	8.80%	11.0%	Baa1 Stable	15.9%	A1 Negative

Q. Can you provide more detail on credit rating agency views regarding the Company's cash flows and resulting credit ratings?

A. Yes. As early as 2018, the Company's ratings have been affected by its weak cash flow. Moody's, in a January 19, 2018 report (see Exhibit_ (YS-5)), after changing the Company's credit outlook from "Stable" to "Negative", commented that:

> CECONY's negative outlook is driven by the negative impact from Federal tax reform, signed into law in December 2017. The resulting deterioration in cash flow, due to the early termination of bonus depreciation among other cash negative provisions, will pressure already weaker financial metrics compared to peers.

In addition, on October 30, 2018, Moody's downgraded the Company's senior unsecured rating from "A2" to "A3" (see Exhibit__(YS-6)). Moody's cited the Company's weak financial profile as the cause of the downgrade. At that time, Moody's commented that the Company's credit challenges were:

- Cash flow headwinds from tax reform; and
- High capex requirements and high dividend payout drive higher debt levels.

Moody's expected the Company's ratio of cash flow from operations before changes in working capital ("CFO pre-WC") to debt to fall to the mid-teens from over 20% historically and warned that the two main factors that could lead to an additional downgrade are (1) CFO pre-WC to debt declining consistently below 15% and (2) a less predictable regulatory environment.

Q. Have any of the ratings agencies commented recently on the Company's cash flow situation?

A. Yes. S&P commented on the Company's weak cash flows in a March 3, 2020 report (see Exhibit__(YS-7)):

> We expect parent Con Ed's financial measures to have minimal cushion for the current rating level throughout our forecast. We expect Con Ed's FFO to debt to average between 16% and 17% throughout the rest of our forecast, largely as a result of new rates for CECONY beginning in 2020.

Fitch, in a September 11, 2020 report (Exhibit__(YS-8)), also mentioned the Company's weakened credit metrics provide little headroom at current rating levels.

Q. Has Moody's made any further changes since their October 31, 2018 report?

A. Yes. On December 23, 2019, Moody's changed the Company's outlook from "stable" to "negative". Subsequently, on March 17, 2020, Moody's downgraded the Company's senior unsecured rating from "A3" to "Baa1" and changed the outlook from "negative" to "stable". (see Exhibit__(YS-9). In the March 17, 2020 report, Moody's stated that the Company's financial metrics have declined in recent years due to:

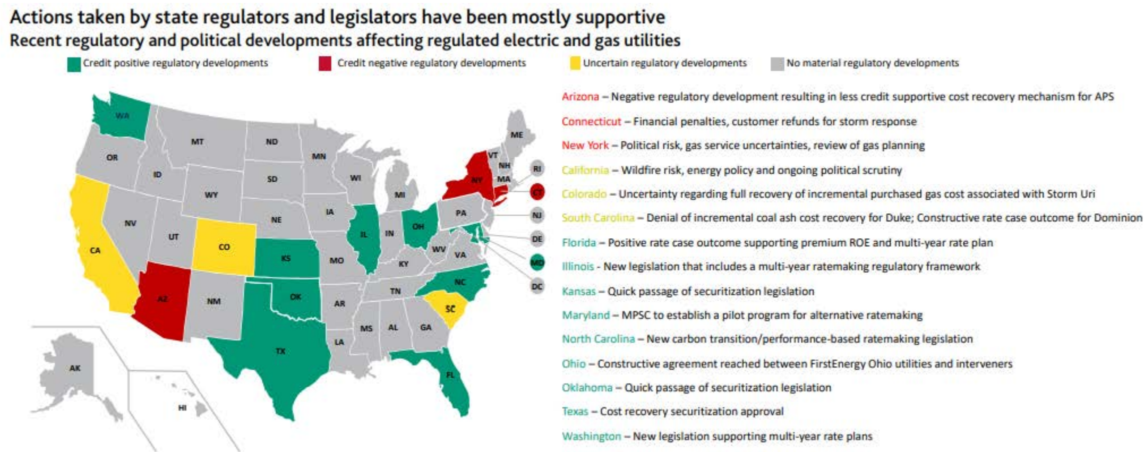
- Weaker financials due to the rate case approved in January 2020;

- The ongoing impacts of tax reform;
- Heightened political intervention; and
- Higher capital spending.

Moody's again cited forecasted declines down to 14%-16% in the Company's ratio of CFO pre-WC to debt and warned that the main factors that could lead to an additional downgrade are (1) CFO pre-WC to debt declining consistently below 14%; (2) Further decline in the predictability and stability of the New York political environment and (3) less regulatory support for cost recovery.

Q. Has Moody's commented specifically on state regulatory developments during the Company's current rate plan?

A. Yes, on November 4, 2021, Moody's published a report that identified New York as one of three regulatory regimes with credit-negative regulatory developments, making it an outlier from other states. See "2022 Outlook Stable on Sustained Regulatory Support for Robust Investment Cycle" (see Exhibit__(YS-10)).



Source: Moody's Investors Service

Q. Did Moody's comment on the New York regulatory situation in other reports?

A. Yes. On November 13, 2020, Moody's published a report titled, "Latest Political Intervention into Regulatory Oversight is Credit Negative for New York Utilities" (see Exhibit__(YS-11). In the report, Moody's discussed proposed legislation, Program Bill Number 13, that would have made it easier to penalize utilities for perceived gaps in storm performance, increase penalty liability, and would have created a process for revoking a utility's franchise.

Q. Can you please discuss the major themes of the November 13, 2020 Moody's report

A. As the title suggests, Moody’s discusses its view that Bill 13 weighed most heavily on credit quality because it would have resulted in a higher business risk environment for every New York utility and their respective holding companies:

> The proposal is credit negative for all New York utilities because it represents the latest in a series of actions by the governor’s office to intervene in utility regulations, which undermines the consistency and predictability of the state’s regulatory framework.

The report indicates that Moody’s believes that the proposal would have negatively impacted the legislative and judicial underpinnings of the New York utility regulatory environment.

Q. Was Bill 13 passed into law?

A. No. The bill was not reintroduced in the 2021 state legislative session.

Q. Has Moody’s commented further on political risks to the Company’s credit quality?

A. Yes. In a Credit Opinion published May 14, 2021, Moody's listed heightened political rhetoric as one of three factors that constrained the Company's credit.

Q. What were the other two factors?

A. They were:

1) the impact that the COVID-19 pandemic has had on customer demand and cash payments, which have declined significantly from normal over the past year; and

2) high capital spending requirements and dividend payout, exacerbating negative free cash flow levels and weakening financial metrics.

Q. Have other credit agencies discussed political risk as a factor affecting Con Edison's credit ratings?

A. Yes. On November 24, 2020, S&P published a report titled "Consolidated Edison Inc. and Subs Outlooks Revised To Negative Amid Potential Political Headwinds; Ratings Affirmed" (see Exhibit__(YS-12)).

Q. What did S&P state as a rationale for the negative outlook?

A. Similar to the Moody's report cited above, S&P expressed concern over increased political intervention in regulatory affairs:

> The extent to which a utility's regulatory construct is insulated from political intervention is an important credit consideration under our ratings methodology. Relative to other jurisdictions, we believe the New York Public Service Commission (NYPSC) may be more exposed to intervention-related risks.

S&P states further:

> As per our criteria, regulatory independence is one of the key attributes that underpins the credit quality of the utility industry, despite the industry typically operating with negative discretionary cash flow and relatively weaker financial measures compared to other industries.

Q. Since the Company’s downgrade, have there been any other examples of political intervention in the regulatory sphere?

A. Yes, in December 2021, Governor Hochul signed into law legislation that requires utilities to provide compensation in the form of bill credits and reimbursement for food and medicine for outages lasting at least 72 hours. Utilities are prohibited from recovering the costs from ratepayers regardless of the magnitude of the storm or the efficiency of the Company’s storm response. This legislation does provide that “a utility company may petition the commission for a waiver of the requirements of this section. The company shall have the burden of demonstrating that granting the waiver is fair, reasonable and in the public interest.”

Q. Has there been any other independent analysis that has evaluated the constructive approach of regulatory agencies around the country?

A. Yes. On May 19, 2021, UBS published a sector report (see Exhibit__(YS-13)) titled “North America Power & Utilities; Updating Regulatory Rankings Amidst Rising Inflation”. In this report, UBS ranks the various North American regulatory jurisdictions based on five criteria: (1) whether commissioners are appointed or elected; (2) allowed return spread history; (3) mechanisms that reduce regulatory lag; (4) rates and customer levels compared to region; (5) tendency to settle versus litigate rate cases; and (6) a subjective investor friendliness factor.

Q. How did New York rank in UBS’ evaluation?

A. New York’s regulatory jurisdiction ranked in the 4th tier. New York has been ranked in this tier since it was downgraded from Tier 3 in February 2018. Even with the current difficulties surrounding the wildfires, New York is considered less constructive than California.

Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
	FERC			
		Washington		
		Colorado		
		Illinois		
		Louisiana		
		New Jersey		
		Ohio		
		Oregon		
		Texas		
		South Carolina		
		Tennessee		
		Wyoming		
		California		
	Utah	Massachusetts	Prince Edward Island	
	Pennsylvania	Ontario	Rhode Island	
Florida	Virginia	Texas	Alaska	New Mexico
Michigan	Arkansas	Delaware	Kansas	Alberta
Wisconsin	Idaho	Maryland	Mississippi	District of Columbia
Georgia	Kentucky	Minnesota	Nevada	Arizona
Alabama	Iowa	Newfoundland & Labrador	New York	Maine
British Columbia	Missouri	Hawaii	Connecticut	South Dakota
Indiana	North Dakota	West Virginia	Nebraska	Vermont
North Carolina	Nova Scotia	Oklahoma	New Hampshire	Montana

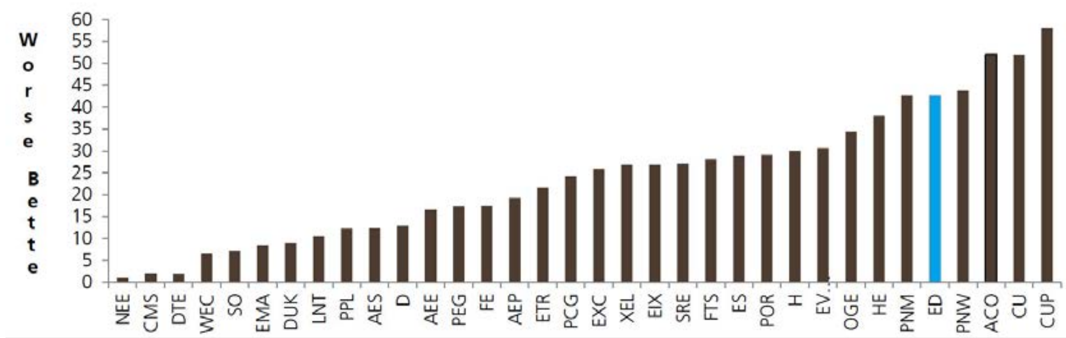
Source: UBS

Jurisdictions highlighted in green denote an improvement over the prior ranking while jurisdictions highlighted in red denote a lower rating over the prior ranking.

Q. Did UBS rank CEI against its regulated utility peers?

A. Yes. As noted in the chart below, UBS ranked CEI 30th out of the 34 companies evaluated by UBS based on UBS’ proprietary ranking of regulatory jurisdictions. In addition, UBS applied a negative five percent discount to the Company's equity valuation to account for the New York regulatory environment.

Weighted Average Regulatory Ranking



Source : S&P Global Market Intelligence, Factset, JD Power, UBS Equity Research

Q. Have other Wall Street equity research analysts applied a valuation discount to Consolidated Edison, Inc.'s ("CEI") equity valuation?

A. Yes. A number of other analysts have applied a discount to how they value CEI's equity. These analysts use a price-to-earnings ("P/E") multiple valuation method to determine their price target. The analysts in the table below first take a P/E multiple that they believe is appropriate for the industry and then apply a discount to that multiple to factor in the risks faced by Consolidated Edison, Inc. The biggest of these risks is the New York regulatory environment risk. As shown in the table below, analysts' P/E valuation discount for CEI range as high as 21.1% and average nearly 10%. This discount makes CEI's access to the equity markets more expensive, on average, relative to its peers.

Report Date	Firm	Industry Price-to-Earnings Multiple	ConEd Price-to-Earnings Multiple	ConEd Valuation Discount (%)
08/20/21	Wells Fargo	20.0x	18.2x	9.0%
08/17/21	Goldman Sachs	19.0x	15.0x	21.1%
08/08/21	UBS	17.7x	16.8x	5.0%
06/01/21	Morningstar	20.0x	18.4x	8.0%
05/07/21	KeyBanc	19.0x	18.0x	5.3%
05/07/21	Guggenheim	19.5x	18.5x	5.1%
05/06/21	Wolfe	18.0x	15.3x	15.0%
Mean		**19.0x**	**17.2x**	**9.8%**

Q. Have any analysts applied a premium to how they value Consolidated Edison, Inc. relative to the utility industry?

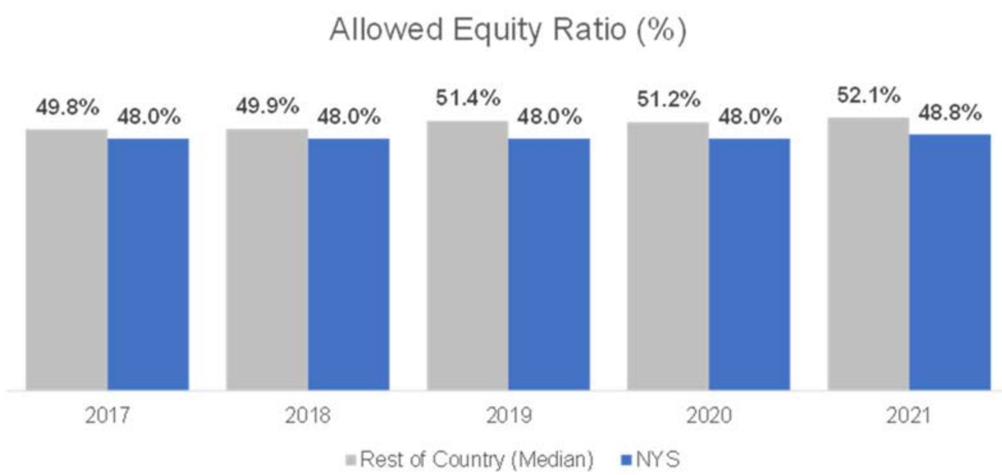
A. No.

Q. What is the significance of the Company and New York regulatory jurisdiction rankings by fixed income and equity analysts?

A. The rankings are an independent confirmation of the deterioration of the New York regulatory environment relative to the rest of the country. A less constructive regulatory environment imposes additional costs for both customers and shareholders. Downgrades of the Company by rating agencies increase the rates at which the Company can borrow debt. In addition, any discount applied by investors to the Company’s equity valuation to account for the less constructive regulatory environment in New York will increase the Company’s cost of equity. The Company will be required to access both the debt and equity markets in the coming years due to weaker cash flows resulting from the increased Covid-19 related arrearages paired with sustained capital spending in order to maintain the Company’s infrastructure, enhance storm resilience, and implement the State’s clean energy agenda. The inability to access the capital markets in an efficient and cost effective manner because of New York’s regulatory environment will negatively impact customers by unnecessarily driving up their costs.

Q. Why is a capital structure with a 50.0% equity ratio reasonable?

A. An equity ratio of 50.0% would bring New York up to the national average. The chart below shows the median equity ratio for the rest of the country over the last five years, as compared with a median equity ratio in New York.



Source: SNL Financial

Q. How would a 50.00% equity ratio potentially impact the Company’s credit profile?

A. A 50.00% equity ratio would be an important signal of the credit supportiveness of the New York regulatory jurisdiction to the credit rating agencies. The rating agencies’ assessment of regulatory framework is an important component of their rating methodology. For example, Moody’s applies a 25% weighting to regulatory framework in its rating methodology. In addition, a higher equity ratio will result in stronger credit metrics for the Company. As noted earlier, Moody’s is most focused on the Company’s CFO pre-WC to total debt ratio, listing “CFO pre-WC to debt declining consistently below 15%” as one factor that could lead to an additional downgrade of the Company’s credit rating.

Q. Does Moody’s indicate a CFO pre-WC to total debt level that could lead to an upgrade?

A. Yes. Moody’s states in the report that a CFO pre-WC to total debt level of 17% could lead to an upgrade back to a rating of A3.

Q. What equity ratio would be necessary to increase CFO pre-WC to total debt to 17%?

A. The chart below shows that an equity ratio of approximately 63% would be needed to reach that level from the current 11.2% that Moody’s has calculated for Con Edison as of June 30, 2021.

	Last 12 Months Ending 6/30/2021	Adjustment for 62.7% Equity Ratio	Pro Forma LTM 6/30/2021
CECONY Electric Rate base	$22,878		$22,878
CECONY Gas Rate base	7,499		7,499
Total Electric and Gas Ratebase	$30,377		$30,377
Allowed Return on Equity	8.80%		
Allowed Equity Ratio	48.00%	62.70%	62.70%
Moody's Credit Ratio			
Cash Flows from Operations (pre-working capital)	$2,282	393	2,704
Total Debt	20,392	(4,465)	15,897
CFO pre-WC / Debt	**11.2%**		**17.0%**

Q. Is the Company requesting a 63% equity ratio?

A. No, this pro forma chart was primarily presented to emphasize the severity of the Company’s weakened cash flows. As discussed earlier, the Company is requesting a moderate increase to an equity ratio of 50.00%, which is consistent with national industry averages.

Q. Will an equity ratio of 50.00% improve the Company’s credit metrics?

A. Yes. The chart below shows that an equity ratio of 50.00% would increase the CFO-pre WC to total debt ratio by 80 basis points to 12.0% from the current 11.2% that Moody’s has calculated for Con Edison as of June 30, 2021.

	Last 12 Months Ending 6/30/2021	Adjustment for 50.00% Equity Ratio	Pro Forma LTM 6/30/2021
CECONY Electric Rate base	$22,878		$22,878
CECONY Gas Rate base	7,499		7,499
Total Electric and Gas Ratebase	$30,377		$30,377
Allowed Return on Equity	8.80%		
Allowed Equity Ratio	48.00%	50.00%	50.00%
Moody's Credit Ratio			
Cash Flows from Operations (pre-working capital)	$2,282	53	2,364
Total Debt	20,392	(608)	19,755
CFO pre-WC / Debt	**11.2%**		**12.0%**

Q. How will a 50.00% allowed equity ratio affect the Company's credit ratings in the near term?

A. A 50.00% allowed equity ratio can help stabilize the Company's ratings by providing additional needed cash flow and by sending a positive signal to the rating agencies that the Commission is willing to support the credit of the Company. The Company's current Outlook from S&P and Fitch is "negative". An increase to 50.00% could help prevent further credit degradation. Fitch, in particular, lists "Unexpected improvement in New York regulatory environment" as one factor that could lead to a positive rating action.

Q. How will a 50.00% allowed equity ratio affect the Company's credit ratings in the long term?

A. Over time, an increase of the allowed equity ratio to 50.00% will provide continued improvement in cash flows and related credit metrics, which could help to avoid downgrades and lead to future credit upgrades.

Q. Has the Company’s equity ratio historically been at or near the allowed equity ratio over time?

A. Yes. Please see the chart below:

Consolidated Edison Company of New York, Inc.
Actual Equity Ratios
12 Month Rate Year Ended

	Allowed Equity Ratio		Actual Equity Ratio	
Rate Year Ending	Electric	Gas	Electric	Gas
October 2016	48%	48%	49%	49%
October 2017	48%	48%	48%	48%
October 2018	48%	48%	47%	47%
December 2019	48%	48%	48%	48%
December 2020*	48%	48%	46%	46%

- 2020 equity ratios reflect COVID-19 related cash flow impacts

Q. Has the Company prepared a required rate of return exhibit?

A. Yes. The document entitled “CONSOLIDATED EDISON COMPANY OF NEW YORK , INC. –– RATE OF RETURN REQUIRED FOR THE RATE YEAR –– THIRTEEN MONTH AVERAGE ENDING DECEMBER 31, 2023,” is set forth as Exhibit AP-5, Schedule 2.

Q. Please describe any projected changes in Con Edison’s long-term debt and how such changes have been incorporated into the required rate of return for the Rate Year (*i.e.*, January 1, 2022 through December 31, 2022).

A. Exhibit AP-5, Schedule 6, presents any projected long-term debt issuance for the Rate Year.

Q. Please describe how you developed the cost of long-term debt.

A. Exhibit AP-5, Schedules 5 and 6, present the detailed calculation of the cost of the long-term debt at September 30, 2021 and for the thirteen-month average ending December 31, 2023, respectively. These schedules detail each issue of long-term debt outstanding and calculate an effective annual cost for each issue, taking into consideration the original net proceeds to the Company and annual interest costs. The sum of the effective annual cost for all issues is divided by the gross amount of debt outstanding to derive the weighted average cost of long-term debt.

Q. Did you provide the interest rate forecasts used as a basis for the cost of debt in this exhibit?

A. Yes.

Q. What method have you used to develop the interest rate forecasts?

A. The Company has used forecasts of Treasury bond rates from the publication *Blue Chip Financial Forecasts*, plus a spread to Treasury bond rates based on indicative quotes from financial institutions. The *Blue Chip Financial Forecasts* consist of the consensus forecast of approximately 45 economists. This approach provides more reasonable forecast results than simply using the most current Treasury bond rates. At the update stage of this proceeding, the Company will revise Exhibit AP-5, Schedule 6, to reflect the most recent data available, as well as any new or refinanced debt that the Company may have issued by that time.

Q. Do you believe that current Treasury rates provide the best estimate of future long-term interest rates?

A. No. The position of Staff in recent base rate proceedings that current Treasury rates are the best estimate of future long-term interest rates relies on academic papers that the Company believes are not relevant.

Q. Can you explain the flaw in Staff’s position?

A. Yes. In the direct testimony of the Staff Finance Panel

(p. 49) submitted in the most recent Orange and Rockland electric and gas base rate cases (*i.e.*, Case 21-E-00745 & 21-G-0073), Staff states that:

> …relatively short-term movements in long-term interest rates are difficult to forecast. Such forecasts are not only poor predictors of the magnitude of the expected change in interest rates, they are not even reliable with respect to the direction of the change. Instead, the best estimate of future long-term interest rates is no-change; in other words, the current rates of these debt instruments.

Q. Did Staff offer any evidence to support their position?

A. Yes. Staff referenced several studies including, "On Forecasting Long-Term Interest Rates: Is the Success of the No-Change Prediction Surprising?" by Dr. James E. Pesando in the Journal of Finance, September 1980, "Just How Bad Are Economists at Predicting Interest Rates? (And What are the Implications for Investors?)" by Kevin Stephenson in the Journal of Investing, Summer 1997, "Professional Forecasts of Interest Rates: Evidence from the Wall Street Journal's Panel of Economists" by Karlyn Mitchell and Douglas K. Pierce in the Journal of Macroeconomics, December 2007, "Predicting Interest Rates: A Comparison of Professional and Market-Based Forecasts" by Michael T. Belongia and published by the Federal Reserve Bank of St. Louis in March 1987, and "Beating the Random Walk: A Performance Assessment of Long-Term Interest Rate Forecasts" by Frank A.C. den Butter and Pieter W. Jensen, published by the Tinbergen Institute in October 2008.

The Company believes that these papers are not relevant to the discussion of forecasted interest rates in this rate case. The collected analyses all predate the 2008 financial crisis and ignore subsequent improvements in forecasting accuracy that have occurred since that time. An article called, "Interest Rate Forecasts in Conventional and Unconventional Monetary Policy Periods" by Nelson Oliver and Mehmet Pasaogullari published by the Federal Reserve Bank of Cleveland in May, 2015 (Exhibit__(YS-14)) states:

> Monetary policy has been conducted with a different set of tools since the financial crisis, and we

> investigate whether the change has affected the accuracy of professionals' interest-rate forecasts. We analyze the accuracy of federal funds rate and nominal Treasury yield forecasts in the periods before and after the introduction of new policy tools and find that, in general, forecast accuracy improved in the latter policy period.

The source of forecasts for the analysis used in this publication is the same *Blue Chip Financial Forecasts* that is used by the Company.

Q. What is a better method than using current rates to forecast rates?

A. A forward looking measure of rates is a better forecasting method. Examples of forward looking measures are the forward rate curve or a consensus of economists' estimates contained in the *Blue Chip Financial Forecasts*. The forward rate is the rate you can lock in today to borrow in the future and can be interpreted as the market's consensus forecast of interest rates. A consensus forecast of Treasury rates, such as that produced by Blue Chip Financial, provides a more reasonable estimate rather than simply relying on current rates.

Q. What stand-alone capital structure for the Company results from the calculations that you described?

A. Exhibit AP-5, Schedule 2, shows the forecasted capital structure for the thirteen months ending December 31, 2023 of 49.11% long-term debt, 0.89% of customer deposits, and 50.00% common stock equity. The Company has no preferred stock outstanding.

Q. Does Exhibit AP-5 also show the forecasted capital structure, based on a thirteen-month average, for the twelve months ending December 31, 2024 and December 31, 2025, respectively?

A. Yes. Schedules 3 and 4 of Exhibit AP-5 show the capital structure for those periods. These schedules show that the debt ratio would increase slightly to 49.06% of the Company's capital structure in 2024 and further decrease slightly to 49.00% in 2025. These schedules also show that the customer deposit ratio would increase modestly to 0.94% in 2024 and 1.00% in 2025. The equity ratio would remain unchanged at 50.00% for the twelve-month periods ending December 2024 and 2025, respectively.

Q. What ROE is the Company proposing be used for purposes of developing a revenue requirement in these filings?

A. The Company proposes an ROE of 10.0% which is at the low end of the recommended range presented by the Company's ROE witness in this proceeding, Bente Villadsen.

Q. What overall rate of return is the Company proposing in these proceedings?

A. Using the Company's proposed capital structure, cost of long-term debt and ROE, the overall rate of return is 7.10% as shown on Exhibit__(AP-5), Schedule 2.

Q. Is the Company presently subject to any financial protection provisions adopted by the Commission?

A. Yes. The Commission continued a number of financial protections when it adopted the Joint Proposal in the Company's last base rate proceedings, Cases 19-E-0065 and 19-G-0066. The current financial protections include that if at the end of each semi-annual period ending June 30 or December 31, investments in CEI's non-utility businesses exceed 15% of CEI's total consolidated operations as measured by revenues, assets, or cash flow, or if the ratio of holding company debt as a percentage of total consolidated debt rises above 20%, the Company shall notify the Commission that a trigger has occurred and submit a filing providing a ring-fencing plan to insulate the Company, or, in the alternative, demonstrating why additional ring-fencing measures are not necessary at that time.

Q. Has the Company been able to maintain investments in CEI’s non-utility businesses below 15% of CEI’s total consolidated operations as measured by revenues, assets, or cash flow and the ratio of holding company debt as a percentage of total consolidated debt below 20%?

A. Yes. Since the financial protections were put in place, the Company has been able to maintain the four ratios below the trigger points.

Q. Does the Company believe that the financial protections should remain in effect in their current form?

A. No. The Commission established the existing financial protections for Con Edison in Cases 16-E-0060 and 16-G-0061. In those Cases, the Finance Panel testimony on May 27, 2016, Staff stated:

> As a result of the recent growth in CEI’s regulated transmission and competitive energy businesses, we believe that additional ring-fencing provisions should be employed in order to insulate the utility from undue risk that may result from these riskier regulated transmission.

In particular, Staff listed investments made by Consolidated Edison Transmission, Inc. in midstream gas transmission and storage projects like Stagecoach Gas Services ("SGS") and Mountain Valley Pipeline ("MVP") as a basis for their judgement that ring-fencing protections were needed.

Q. Is that view still valid?

A. No. CEI has publicly announced that it will no longer invest in long-haul natural gas pipelines, has divested its interest in SGS and has capped its investment level in MVP. In addition, the Company's significant forecasted environmental capital investments will make it by far the largest user of capital in the CEI family.

III. CAPITAL NEEDS AND INVESTOR CONCERNS

Q. Please describe the financial challenges facing the Company during the Rate Year and beyond.

A. The Company faces the following interrelated financial challenges: (A) the capital intensive nature of its business; (B) the costs of implementing clean energy projects pursuant to government and regulatory authority policies to fight climate change and improve resilience to extreme weather; (C) flat demand growth for electricity; (D) its unusually weak cash flows; (E) the restrictions that regulation places on its ability to respond to unfavorable developments in its environment, and (F) its dependence on the market to fund its capital needs. Each of these challenges is discussed further below.

Q. Please discuss the capital intensive nature of the Company’s business.

A. The Company’s business requires significant capital investment every year, its assets are long-lived and the underlying technology, facilities and customer base are mature. Capital intensity is high for utilities. According to a June 2, 2011, IHS Cambridge Energy Research Associates presentation titled "*Post Fukushima: If not nuclear, what energy mix?*, the electric utility industry is the most capital intensive industry as measured by the ratio of total assets to total revenues. As shown on Exhibit___(YS-15), which was prepared under my supervision and direction, the Company’s capital intensity can be demonstrated by the fact that its ratio of net fixed assets per dollar of revenues is 3.7, as compared with 2.9 for the average S&P 500 company and 0.2

for the median company. Capital intensity amplifies risk for investors because capital intensive businesses have to recover much larger fixed costs (interest and depreciation) before achieving a return on their investment. Even factoring in the Climate Leadership and Community Protection Act ("CLCPA"), the Company's assets also have extraordinarily long lives. Long-lived assets, in the context of rate regulation, present two financial challenges for the Company that are also risks for potential investors in the Company's debt issuances and equity shares. First, their investment horizons for capital recovery must be much longer. For debt investors, utility debt has much longer average maturities than other companies. Equity investors must also wait longer for repayment on their investment. Second, there is a regulatory risk in long-lived assets because United States rate regulation limits returns to a fraction of historic tangible book value rather than replacement or current market value. The Company's depreciation recoveries, which reflect historic tangible net book values, are small relative to its current capital costs, returning only 47% of its capital expenditures in the form of depreciation for the twelve months ended December 31, 2020.

Due to the long depreciation lives established in rates, this dynamic is likely to continue for many years. As shown on Exhibit___(YS-16), which was prepared under my supervision and direction, by way of comparison, the average S&P 500 company recovered 200% of its capital expenditures through depreciation/amortization. This would have placed Con Edison near the bottom 13% of companies in the S&P 500 that had meaningful recovery rates. Con Edison (which had a 44% capital expenditure recovery rate) would have ranked below 11 of the 26 utilities in the S&P 500 as shown on Exhibit___(YS-17), which was prepared under my supervision and direction. The average recovery rate for the utility companies in the S&P 500 was 62%.

The Company’s large installed base of mature equipment requires a continuous investment in replacement assets. In other industries, a much larger portion of investment can be dedicated to new business (generating offsetting revenues) or new technology (lowering costs).

Mature assets raise operating costs and increase operating risks, particularly in an environment that requires high levels of reliability and imposes virtually automatic regulatory penalties for failing to achieve it. The technology of the business is also mature, affording little opportunity to significantly reduce invested capital in the business through technological innovation. The need for continuous investment to maintain and improve the system with slight opportunities for demand growth and limited depreciation cash flow means that the Company must seek rate increases and raise new capital frequently to maintain its financial stability. Replacement capital needs alone substantially exceed the cash generated through depreciation recoveries for the Company.

Q. Please discuss the costs of implementing clean energy projects pursuant to government and regulatory policies to fight climate change and enhance resilience to extreme weather.

A. In July 2019, the State of New York adopted the CLCPA, which establishes a framework for the state to reach a net zero emissions level for greenhouse gasses by 2050. Among the major requirements of this act are (1) emissions reductions of 40% by 2030 and 85% by 2050, (2) 70% of electricity must come from renewable resources by 2030 and 100% by 2040, (3) a reduction of statewide energy consumption by 185 BTU through energy efficiency improvements. In January 2020 the Commission issued an order titled “New Efficiency: New York” (“NENY”), which established programs to support the CLCPA targets. According to the NENY order, the Company is required, within the bounds set by the order, to conduct energy efficiency programs and incorporate energy efficiency targets and budgets consistent with the order. Incremental budget spending authorized under the order for 2021-2025 is $593.3 million for electric and $235.5 million for gas. The Company expects to continue recovery of these costs as a regulatory asset.

Q. Please describe proposed capital projects needed for the Company to meet the stated CLCPA environmental targets.

A. In 2021, the Company proposed, and the Commission granted cost recovery for, a $780 million investment in three New York City electric transmission projects that will facilitate the retirement of fossil-fuel powered “peaking” generation units, bringing air-quality benefits to environmental justice communities, and will help to deliver renewable power to our customers.

Q. Is the Company proposing further capital projects to meet the CLCPA environmental targets?

A. Yes. In addition to the $780 million projects mentioned earlier, the Company plans to spend $5,350 million on an additional eight local transmission and distribution system projects to allow for interconnection and delivery of new renewable generation resources within the Company’s system.

Q. Please describe the challenges of financing this CLCPA capital expenditure program.

A. The Company has historically funded its large existing capital expenditures through a combination of funds from operations and external debt and equity financing, but funding construction of the projects needed to meet CLCPA targets will substantially increase the Company’s reliance on external funding sources. The Company’s allowed ROE and equity ratio need to be sufficiently high that equity investors will be able to earn an appropriate return on their investment and debt investors will be assured that the Company’s cash flows will be sufficient to meet its payment obligations.

Q. Please describe how the Company’s weak cash flows present a financial challenge.

A. Because the Company will continue to be challenged by its weak operating cash flows and lack of positive free cash flows, Con Edison will continue to be more dependent on external funding, particularly with its capital plans to implement CLCPA programs.

Q. Please describe how restrictions on the Company's business imposed by the Commission present a financial challenge.

A. The Company is subject to various regulatory restrictions that limit its ability to react to unfavorable circumstances. For example, the Company has an obligation to serve and can be required to do so even if doing so entails significant investment upon unfavorable terms. It also is limited in its ability to reach beyond its franchise area to serve attractive new customers. The Company's assets are immovable; unlike those of most companies, they cannot be used in a different location or business, their usefulness and profitability are tied to providing utility service in its New York service territory.

Unlike non-utility companies, Con Edison has a limited ability to retain the advantages of its efforts to improve its efficiency and thus lower its costs of doing business for the benefit of its equity investors. The Commission routinely requires earnings sharing mechanisms, which serve to limit earnings opportunities, as a component of base rate case settlements. Moreover, any additional efficiencies achieved are fully allocated to customers each time base rates are reset, given the capital recovery and cash flow parameters of historic cost-of-service rate making.

Q. Please describe how the fact that the Company must continually raise capital increases risk for existing and prospective equity investors.

A. As mentioned earlier in my direct testimony, the Company must approach the markets for additional new debt capital on a frequent basis. Con Edison is forecasted to raise $1,025 million in 2023, $1,325 million in 2024, and $1,150 million in 2025. The Company will need the assurances of positive cash flows and favorable regulatory support to continue to market this debt at reasonable rates.

Each time Con Edison markets its debt securities, investors will assess the risks they would bear if they invested in the Company in light of the challenges identified above. Their assessment of these risks is, and will be, priced into the cost of debt each time the Company seeks new capital in the years ahead. To the extent that analysis of risk leads the market to reduce stock prices or raise interest rates, the existing investors are disadvantaged and other potential investors are made more wary. Through this cycle of investors assessing and pricing risks that the Company faces, customers are negatively impacted through increases in the cost of financing the Company’s capital investment needs. To raise this capital at a reasonable cost, the Company must remain an attractive investment to both debt and equity investors. To remain attractive to these investors, Con Edison must receive fair and reasonable treatment from its regulators.

Q. How much and what type of debt does the Company have outstanding?

A. As of September 30, 2021 Con Edison had $17,637 million of long-term debt.

Q. Who owns the Company’s debt?

A. Investment managers, insurance companies, pension plans, hedge funds, banks, trust companies and individuals.

Q. How do bond investors evaluate Con Edison?

A. For most investors, the credit ratings assigned by the nationally recognized statistical rating organizations (*i.e.*, Moody’s, S&P and Fitch) are the threshold basis for evaluating individual corporate credits such as those offered by the Company.

Q. What are the current ratings on Company debt?

A. The long-term, senior unsecured debt ratings are Baa1, A-, and A- by Moody's, S&P, and Fitch, respectively. The short-term debt is rated P-2, A-2, and F2, respectively. S&P and Fitch have their outlooks at Negative.

Q. Are bond ratings the correct indicator of the risks to shareholders?

A. No. The priority of bondholders' claim on the Company means that shareholders are subject to a higher level of risk. Shareholders, unlike bondholders, only have a residual claim to the resources and income of the Company, and thus face risks even in well-rated companies. If returns are inadequate, the bondholder may suffer a loss on paper from a credit downgrade. The stockholder will suffer the loss directly through a drop in the share price and/or through a lower dividend.

Q. Why do companies such as Con Edison need to maintain a particularly strong financial condition?

A. Capital intensive companies with a statutory obligation to serve have to borrow despite the state of the market because they need continuous access to capital. In addition, utilities may have to access the capital market in response to a natural catastrophe *e.g.*, Superstorm Sandy. When utilities are forced to pay high rates, these rates will remain with the companies and their customers for as long as 30 years. On the short-end of the maturity spectrum, access to commercial paper and bank borrowing markets is key to allowing the Company to pay for energy that must be delivered, no matter the price. Only A-1/P-1 borrowers can maintain that access in all markets. Such access has become more tenuous for Con Edison due to its current A-2/P-2 (S&P's/ Moody's) rating for commercial paper. At the height of the financial crisis of 2008-2009, non-A-1/P-1 borrowers, if they had access to commercial paper market, paid significantly higher rates. The same was true in the early days of the COVID-19 pandemic where A2/P2 commercial paper peaked at 3.61% on March 26, 2020 versus an average of 1.76% for the pre-pandemic months of January and February 2020.

During both times, the seizing up of the commercial paper market was relieved only by the Federal government's intervention to provide an effective backstop for the highest-rated (A-1/P-1) commercial paper issuers, a solution that may not always be available.

If the Company were to lose access to the commercial paper market, borrowing costs would increase as the Company would have to rely more upon long-term debt, which is more expensive. In addition, the Company could be forced to issue debt with less attractive terms because it lacked the flexibility to wait for better market conditions. The recent past has demonstrated the importance of maintaining a strong credit rating and investor confidence in our credit.

Q. Please explain why maintaining or improving its current debt ratings is important for Con Edison.

A. The Company has a significant continuing construction program that must be funded in large part by debt financing. Access to credit markets will be restrictive for lower quality creditors. In addition, a part of the Company’s financing program is comprised of short-term borrowing through its commercial paper program. Such borrowing is highly sensitive to credit quality and credit market conditions.

Q. Are there any additional factors that debt investors will consider when evaluating whether to invest in the Company?

A. Debt investors will also look at the Company’s ability to access the equity capital markets. The Company’s capital needs are fulfilled by both debt and equity investors in approximately the proportion allowed in the Company’s rate plans. In the Company’s capital structure, capital provided by equity investors is subordinate to the capital provided by debt investors. Thus, the ability to access the fixed income markets at a reasonable costs is also dependent on access to equity capital markets.

Q. Who owns the Company?

A. Con Edison has one shareholder, CEI. CEI, in turn, is owned by approximately 60,000 registered shareholders. Registered shareholders are the individuals or businesses whose names are listed on the shareholder register of CEI.

Q. What are the characteristics of the registered shareholders?

A. CEI’s registered shareholders consist of individuals and institutional investors. Institutional investors often own shares for the benefit of others. These investors purchase CEI shares for the benefit of their investors who, in turn, may be pension funds or other individual investors. Because pension funds exist for the benefit of the individual participants in their plans, it makes sense to think of the ultimate beneficiaries of share ownership in CEI, and derivatively in the Company, of being millions of individuals who may own shares directly, invest in U.S. stock mutual funds, or receive or expect benefits from pension plans or life insurance policies.

Q. What do the people who own CEI shares, either directly or indirectly, provide to the Company?

A. They provide the capital that the Company needs above and beyond what debt investors provide. Their capital allows the Company to provide safe, reliable energy utility service to the Company’s customers. Without these shareholders, the Company’s customers would have to pay currently for all of the costs of the services they receive. For example, without these shareholders, customers would have to pay for a new substation as it is constructed rather than over the subsequent decades during which they benefit from its operation.

Q. What do these equity investors expect in return?

A. They expect compensation either in the form of a periodic dividend payment or an increase in the value of the business, or both.

Q. How do equity investors in regulated utilities set their expectations for compensation?

A. The return expectations of equity investors in rate-regulated energy utilities are grounded in “the regulatory compact.” The regulatory compact’s essence is that equity investors forgo the monopoly earnings they would otherwise enjoy in return for the institutionalization of their monopoly in a defined geographic area and a fair and equitable return on the capital they have invested.

Q. What standards exist to help equity investors and regulators determine whether a rate-regulated utility offers a fair and equitable return?

A. The general standards for a fair and equitable return for investors in utility shares are well-established in the U.S. The underlying requirement for fair treatment for equity investors has been recognized for years. As discussed in the direct testimony of Company witness Villadsen, it dates back to the *Hope* and *Bluefield* cases. The U.S. Supreme Court in those cases established that in determining the fairness or reasonableness of a utility’s allowed ROE, one needed to look at the consistency of a utility’s allowed ROE with the returns on equity investments in other businesses having similar or comparable risks.

Q. How would a potential equity investor evaluate the return limitations on New York utilities as to their magnitude, timing and probability?

A. There are four significant factors in an equity investor’s assessment of New York utility regulation: (1) authorized rate of ROE, (2) the likelihood of earning that ROE, (3) the symmetry of potential earned equity returns, and (4) the restrictions the regulator places on the scope of the business. To make this assessment, a potential equity investor will start with the basic parameters of the Commission’s rate orders.

Q. How do the Commission’s rate orders influence investors’ evaluation of the first identified return consideration?

A. The first factor, the authorized rate of ROE, is important for an equity investor because it provides the most visible indication in the rate order of the regulator’s willingness to balance the needs of investors and customers.

Q. How have the Commission’s authorized returns compared to those in other jurisdictions?

A. As we demonstrate in this case and have demonstrated in previous rate cases, the rates of allowed return granted in New York are well below those in other states. I have provided a comparison of allowed returns in New York as compared with other states (based on data from Regulatory Research Associates ("RRA")) to demonstrate the consistency of this practice (see Exhibit___(YS-18),) which was prepared under my supervision and direction). In past cases, Staff has argued that each of the rate cases in the RRA database is unique and, therefore, no meaningful conclusion can be drawn. While I would agree that each rate case is unique, it is equally obvious that meaningful conclusions can be drawn about the New York regulatory environment when New York companies' returns are consistently among the lowest in the country.

Q. Staff has pointed to the various regulatory recovery mechanisms authorized by the Commission as a justification for the low authorized ROEs granted to New York State utilities. Do you agree with Staff's position?

A. No, I do not. The regulatory recovery mechanisms that New York State provides are not distinctive among the U.S. regulatory jurisdictions. As set forth in

Exhibit___(YS-19), which was prepared under my supervision and direction, many of the mechanisms put in place by the Commission are currently in use in other jurisdictions. Accordingly, these mechanisms do not compensate for the low ROEs consistently granted by the Commission.

Q. Can investors readily measure the degree to which a regulatory regime fairly rewards shareholders?

A. In New York, yes. The Commission has a clear and long-standing policy of setting returns relative to the historic tangible book value of the investors' shares. Information about returns on share book values for publicly-traded U.S. companies is readily available to investors from public sources as a basis for comparison.

Q. How does Con Edison compare to this universe of alternative investments?

A. Con Edison does not fare well in the comparison. When looking at the five-year historical average return on book equity, the Company had a return that would have placed it near the bottom third of S&P companies with meaningful available data. The return for the average S&P company was 21.6%. The comparable return on book equity for Con Edison was 8.8%.

Q. Have you prepared an exhibit to show this?

A. Yes, please refer to Exhibit___(YS-20), which was prepared under my supervision and direction.

Q. Are companies typically valued by investors at their book value?

A. No, they are valued by investors based on their future business prospects. Exhibit___(YS-21), which was prepared under my supervision and direction, shows the five-year average market to book ratios for those S&P companies with positive book equity. CEI's market to book ratio is in the bottom 10% of companies for this important measure of investor perceptions and expectations.

Q. How would an investor assess the second factor: the likelihood of a utility actually earning the authorized equity return?

A. The investor would analyze the adjustments made to actual costs that are allowed to be recovered, imputed productivity that may or may not be achieved, and any other revenue or expense adjustments. To the extent that such adjustments are made to real costs, the authorized rate of return is unlikely to be achieved.

Q. Have investors indicated concern with the Company's ability to earn its authorized ROE?

A. Yes. Under the current rate plans, investors have persistently questioned whether the Company will be able earn its authorized ROE and specifically noted the large efficiency imputations and the potential exposure on additional storm mobilization and response costs. The COVID-19 pandemic and delay in COVID-19 related recoveries brought a new sense of urgency to investor questions. Investors are now quite skeptical that the Company can earn its authorized ROE.

Q. Has the Company earned its authorized ROE under its current rate plans?

A. No. The Company files its earned ROE annually with the Commission using the earning sharing calculation set forth in its rate plans. As seen in the chart below, the Company’s filed ROE has been below the authorized ROE for both 2020 and 2021.

Consolidated Edison Company of New York, Inc.		
ROE Analysis		
2020	**Electric**	**Gas**
ROE - Authorized	8.80%	8.80%
ROE - as Filed	8.50%	8.40%
Adjustment for Late Payment and Other Fees	0.27%	0.13%
2021 (work in progress)	**Electric**	**Gas**
ROE - Authorized	8.80%	8.80%
ROE - to be Filed	8.06%	8.96%

Q. The Commission recently authorized the Company’s recovery of unbilled late payment and other fees for 2020 through 2023. Will that raise the Company’s filed ROE?

A. The Company will restate its 2020 filed ROE to account for the additional recovery, but it will still have earned below the authorized ROE (as seen in the chart, the electric adjustment is an additional 0.27% and the gas adjustment an additional 0.13%). The 2021 ROE to be filed next month includes recovery of late payment and other fees. Even with that additional recovery, the Company will have earned an ROE of 8.06% for its largest business in 2021.

Q. How would an investor assess the third factor: the symmetry of potential returns?

A. There is ample opportunity through a system where potential negative revenue adjustments are far larger than potential positive incentives, as well as one-way true-ups of costs--burdens which have been imposed in New York rate decisions--to realize significantly lower returns than the authorized authorized return. All of these aspects of New York rate orders produce asymmetry in expected returns, which a rational potential equity investor would judge as ultimately reducing his or her expected return. Little evidence exists that these burdens are common in other jurisdictions in the country, where the peers that are the basis for the Commission's DCF and Capital Asset Pricing Model ("CAPM") results operate.

Q. How would an investor assess the fourth factor: the restrictions the regulator places on the scope of the business?

A. The adverse impact of the last factor is less quantifiable because it consists of opportunities foreclosed to the Company and thus to the investor. Restrictions on investments in generation in New York, and the punitive indirect restrictions on affiliate company capitalization, reduce the value of the Company to its owners, albeit in ways that are difficult to quantify explicitly.

Q. Have the shortcomings in the treatment of the Company been reflected in equity analysts' views of CEI?

A. Yes. As of December 14, 2021, CEI ranked as 503 of the 505 companies in the S&P 500 in terms of analyst buy/sell rankings (see Exhibit___(YS-22), which was prepared under my supervision and direction).

IV. <u>CONCLUSION</u>

Q. Please summarize your testimony regarding the financial challenges facing the Company.

A. My testimony concerns the financial challenges and the need to maintain access to financial markets at reasonable cost. Both equity and debt investors perceive that the New York regulatory environment is a difficult one in which to operate. Such a perception, if it continues, will make the financing of needed expenditures more expensive in normal times and less certain in times of financial crises.

To avoid such an outcome, and to re-establish debt and equity investors' trust in the fairness of New York regulation, a fair and equitable rate of return, competitive with those available elsewhere in the market, and a reasonable chance to actually earn that return, are needed. And to achieve such, the Commission should grant the rate of return and capital structure requested by the Company.

Q. Does that conclude your direct testimony?

A. Yes, it does.

BEFORE THE

STATE OF NEW YORK PUBLIC SERVICE COMMISSION

CASE 22-E-[xxxx]	)))))	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service.
CASE 22-G-[xxxx]	)))))	Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service.

DIRECT TESTIMONY OF DR. BENTE VILLADSEN

RETURN ON EQUITY

January 28, 2022

Brattle

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BEFORE THE

STATE OF NEW YORK PUBLIC SERVICE COMMISSION

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1. INTRODUCTION

Q1: Please state your name, occupation, and business address for the record.

A1: My name is Bente Villadsen and I am a Principal of The Brattle Group, whose business address is One Beacon Street, Suite 2600, Boston, Massachusetts, 02108.

Q2: Briefly describe your education and professional qualifications.

A2: I have more than 20 years of experience working with regulated utilities on cost of capital and related matters. My practice focuses on cost of capital, regulatory finance, and accounting issues. I am the co-author of the text, “Risk and Return for Regulated Industries” and a frequent speaker on regulated finance at conferences and webinars. I have testified or filed expert reports on cost of capital in Alaska, Arizona, California, Hawaii, Illinois, Iowa, Michigan, New Mexico, New York, Oregon, Ohio, and Washington as well as before the Bonneville Power Administration, Federal Energy Regulatory Commission (“FERC”), the Surface Transportation Board, the Alberta Utilities Commission, the Ontario Energy Board, Quebec’s Regie, and Mexico’s Comisión Reguladora de Energía. I have provided white papers on cost of capital to the regulators in Australia, Canada, and Europe. I have testified or filed testimony on regulatory accounting issues before FERC, the Regulatory Commission of Alaska, the Michigan Public Service Commission, the Texas Public Utility Commission as well as in international and U.S. arbitrations and regularly provide advice to utilities on regulatory matters as well as risk management.

I have previously filed testimony before the State of New York Public Service Commission ("NYS PSC" or "Commission") in Case Nos. 21-E-0074 and 19-00317.

I hold a Ph.D. from Yale University and as BS/MS from University of Aarhus, Denmark. Exhibit BV-1 contains more information on my professional qualifications as well as a list of my prior testimonies and publications.

Q3: What is the purpose of your testimony in this proceeding?

A3: Consolidated Edison Company of New York ("CECONY" or the "Company") has asked me to estimate the cost of equity that the Commission should allow CECONY an opportunity to earn on the equity financed portion of its regulated electric and gas utility rate base in New York. Specifically, I performed cost of equity analysis and provide return on equity ("ROE") estimates derived from market data for a proxy group of regulated electric, natural gas, and water distribution utilities, and provide additional estimates based on an analysis of allowed utility risk premiums. I also consider the relative risk of CECONY and its proposed regulatory capital structure ratio to arrive at my recommendation for the allowed Return on Equity ("ROE").

2. SUMMARY OF CONCLUSIONS

Q4: Do you have any preliminary comments regarding the appropriate ROE?

A4: The current determination of CECONY's allowed ROE takes place during uncertain economic and financial conditions due to the ongoing impacts of the COVID-19 pandemic (including the discovery of new variants), which has led to extremely low U.S. Treasury bond yields, substantial fiscal and monetary initiatives, and 30-year high inflation.

In the light of the current economic conditions and my results, CECONY's request for a ROE of 10 percent and a capital structure with 50 percent equity is conservative. My analysis results in a recommended range of 10-10.5 percent for ROE after taking into account CECONY's specific risk.

Preliminarily, I note that the determination of CECONY's allowed ROE takes place during times of great uncertainty for electric and gas utilities. The COVID-19 pandemic has substantially impacted all aspects of society, including customers' use of electricity and gas, and as noted, the period has been characterized by very active fiscal and monetary policy. The currently very low interest rate is expected to increase. Notably, the Federal Reserve following its December 14-15, 2021 meeting indicated a slow-down in its support for treasury and mortgage-backed securities and stated:

> In light of inflation developments and the further improvement in the labor market, the Committee decided to reduce the monthly pace of its net asset purchases by $20 billion for Treasury securities and $10 billion for agency mortgage-backed securities. Beginning in January, the Committee will increase its holdings of Treasury securities by at least $40 billion per month and of agency mortgage-backed securities by at least $20 billion per month. The Committee judges that similar reductions in the pace of net asset purchases will likely be appropriate each month, but it is prepared to adjust the pace of purchases if warranted by changes in the economic outlook.[1]

For a utility such as CECONY this means that the Federal Reserve is expecting to undertake fewer market transactions to keep treasury / mortgage-backed security prices high (i.e., interest rates low). Therefore, the result is expected to be an increase in interest rates. Of note, this is also the first time the Federal Reserve has acknowledged that inflation is an issue for the U.S. economy.[2]

As of October 2021, electric and gas utility betas average 0.91 and 0.88, which is non-trivially higher than the beta estimates as of, for example, November 2018 where electric and gas utility betas averaged approximately 0.60 and 0.70, respectively. Thus, the systemic risk of the industry has increased, as has the cost of equity (all else equal).

[1] Federal Reserve Board of Governors, "Federal Reserve issues FOCM Statement," December 15, 2021.

[2] The inflation for November 2021 was 6.8% and has been above 5.0% for seven consecutive months. See: Historical Inflation Rates: 1914-2021 | US Inflation Calculator

When evaluating the cost of equity, it is also important to consider business risks to long-term development for electric and natural gas distribution utilities such as CECONY. CECONY is smaller than the average sample company and is facing significant energy and climate policy changes in New York State. The presence of such uncertainty for the industry increases business risk and hence the cost of equity. I further discuss how these and other business risk factors affect the cost of equity in Section 6.

Q5: Please summarize your recommendations for CECONY's ROE.

A5: I recommend that CECONY be allowed to earn a return on equity of 10-10.5% percent on its regulated rate base at the requested 50% percent equity capital structure. The 10 percent ROE requested by CECONY is conservative. I find that the reasonable range for electric utilities is 9.5 to 10.5 percent. I recommend CECONY's range be in the upper half of that range, 10.0 to 10.5 percent, due to its specific risks. The return on equity that is being determined now is expected to be applicable in future years (e.g., 2023 and beyond), so CECONY will be exposed to economic changes over the period for which rates are set. Because the allowed return on equity is a nominal return, it includes today's inflation, but going forward the inflation could readily change. Historically, inflation has impacted not only product prices but also the cost of capital. Therefore, it is important to ensure the ROE set in this case considers the likely future cost of equity.[3]

The data shows a similar range for gas distribution utilities. The results from these two industries reflects CECONY's business risk. This recommendation is based on my implementation of standard cost of capital estimation models including two versions each of the Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM"), as well as an Implied Risk Premium analysis and an analysis of CECONY's business risk. Figure 1 below summarizes the model results using the requested 50 percent equity capital structure. The table also presents the corresponding reasonable ranges, which I discuss further in Section 5 below.

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[3] For example, the correlation between the allowed ROE and the CPI inflation the prior period since 1992 has been about 34%.

Figure 1: Summary of Reasonable Ranges of Estimates at 50% Equity

	Electric Sample	Gas Sample	Full Sample
CAPM/ ECAPM	10.25% - 11.25%	10.25% - 11.25%	10.25% - 11.25%
DCF*	9% - 10%	9% - 10%	9% - 10%
Risk Premium	9.8%	9.7%	9.7% - 9.8%

Note: Full sample considers electric and natural gas utilities

*The lower figure is that from the multi-stage model, while the higher number originates from the single stage DCF results are non-trivially higher.

Based on my consideration of the results from the various cost of capital estimation models, as well as the context of New York State and CECONY's specific risk, I believe it is appropriate to place CECONY's allowed return in the upper half of the reasonable ranges. As such, I recommend a 10.0 to 10.5% ROE.

Q6: Do you have other recommendations?

A6: Yes. I recommend in Section 6 that CECONY be allowed to recover flotation costs associated with the issuance of equity shares that supports the Company's assets.

Q7: How is the remainder of your testimony organized?

A7: Section 3 formally defines the cost of capital and explains the techniques for estimating it in the context of utility rate regulation. Section 4 discusses conditions and trends in capital markets and their impacts on the cost of capital. Section 5 explains my analyses and presents the results. Section 6 discusses CECONY's business risk characteristics, unique risks facing New York-based utilities and other business risks specific to CECONY that are relevant to my recommended allowed ROE. Finally, Section 7 concludes with a summary of my recommendations.

3. COST OF CAPITAL PRINCIPLES AND APPROACH

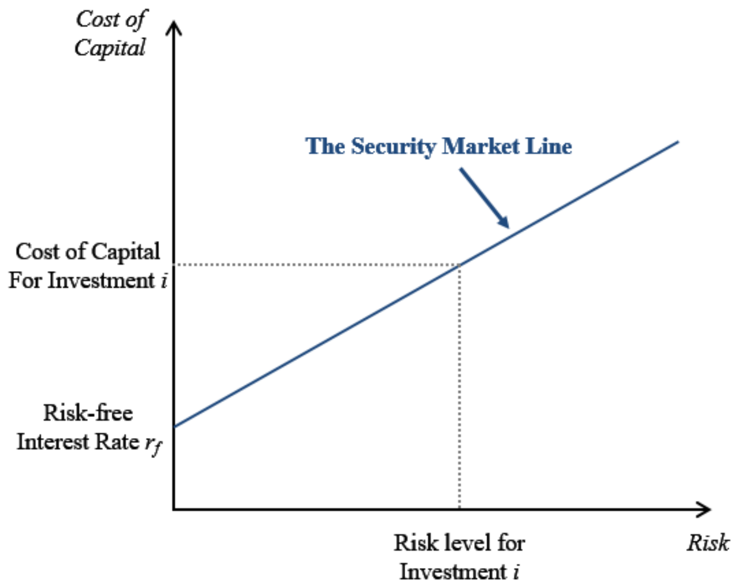
A. Risk and the Cost of Capital

Q8: How is the "Cost of Capital" defined?

A8: The cost of capital is defined as the expected rate of return in capital markets on alternative investments of equivalent risk. Put differently, it is the rate of return investors require based on the risk-return alternatives available in competitive capital markets. The cost of capital is a type of opportunity cost: it represents the rate of return that investors could expect to earn elsewhere without bearing more risk. "Expected" is used in the statistical sense: the mean of the distribution of possible outcomes. The terms "expect" and "expected," as in the definition of the cost of capital itself, refer to the probability-weighted average over all possible outcomes.

The definition of the cost of capital recognizes a tradeoff between risk and return that can be represented by the "security market risk-return line" or "Security Market Line" for short. This line is depicted in Figure 2 below. The higher the risk, the higher the cost of capital required.

Figure 2: The Security Market Line



Q9: What factors contribute to systematic risk for an equity investment?

A9: When estimating the cost of equity for a given asset or business venture, two categories of risk are important. The first is business risk, which is the degree to which the cash flows generated by the business (and its assets) vary in response to moves in the broader market. In context of the CAPM, business risk can be quantified in terms of an "assets beta" or "unlevered beta." For a company with an assets beta of 1, the value of its enterprise will increase (decrease) by 1% for a 1% increase (decline) in the market index.

The second category of risk relevant for an equity investment depends on how the business enterprise is financed and is called financial risk. Section B below explains how financial risk affects the systematic risk of equity.

Q10: What are the guiding standards that define a just and reasonable allowed rate of return on rate-regulated utility investments?

A10: The seminal guidance on this topic was provided by the U.S. Supreme Court in the Hope and Bluefield cases,[4] which found that:

- The return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks;[5]
- The return should be reasonably sufficient to assure confidence in the financial soundness of the utility; and
- The return should be adequate, under efficient and economical management for the utility to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties.[6]

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[4] *Bluefield Water Works & Improvement Co. v. Public Service Com'n of West Virginia*, 262 U.S. 679 (1923) ("*Bluefield*"), and *Federal Power Com'n v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) ("*Hope*").

[5] *Hope*, 320 U.S. at 603.

[6] *Bluefield*, 262 U.S. at 680.

Q11: How does the standard for just and reasonable rate of return relate to the cost of capital?

A11: The first component of the *Hope and Bluefield* standard, as articulated above, is directly aligned with the financial concept of the opportunity cost of capital.[7] The cost of capital is the rate of return investors can expect to earn in capital markets on alternative investments of equivalent risk.[8]

By investing in a regulated utility asset, investors are tying up some capital in that investment, thereby foregoing alternative investment opportunities. Hence, the investors are incurring an "opportunity cost" equal to the returns available on those alternative investments. The allowed return on equity needs to be at least as high as the expected return offered by alternative investments of equivalent risk or investors will choose these alternatives instead. If it is not, the utility's ability to raise capital and fund its operations will be negatively impacted. This is a fundamental concept in cost of capital proceedings for regulated utilities such as CECONY.

Q12: Please summarize how you considered risk when estimating the cost of capital.

A12: To evaluate comparable business risk, I looked to a proxy group of regulated electric, natural gas, and water utilities. The electric, natural gas, and water utilities I consider have a high proportion of regulated assets and revenue with the majority having more than 80 percent of assets subject to regulation. My recommendation focuses on the electric utilities group as the Commission in the past has referenced an electric group for electric and gas utilities in New York.[9] Additionally, they all have a network of assets that are used to serve end-use customers and they are capital intensive (meaning that each dollar in revenue requires substantial investment in fixed assets). Further (as explained in Section B below), I analyzed

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[7] A formal link between the opportunity cost of capital as defined by financial economics and the proper expected rate of return for utilities was developed by Stewart C. Myers, "Application of Finance Theory to Public Utility Rate Cases," Bell Journal of Economics & Management Science 3:58-97 (1972).

[8] The opportunity cost of capital is also referred to as simply the "cost of capital," and can be equivalently described in terms of the "required return" needed to attract investment in a particular security or other asset (i.e., the level of expected return at which investors will find that asset at least as attractive as an alternative investment).

[9] See, for example, State of New York Public Service Commission, "Staff Finance Panel Testimony", Case Nos. 18-E-0067, 18-G-0068, May 2018 as well as 19-E-0065 and 19-G-0066, May 2019.

and adjusted for differences in financial risk due to different levels of financial leverage among the proxy companies and between the capital structures of the proxy companies and the regulatory capital structure that will be applied to CECONY for ratemaking purposes. To determine where in the estimated range of CECONY's ROE reasonably falls, I compared the business risk of CECONY to that of the proxy group companies.

B. Financial Risk and the Cost of Equity

Q13: How does capital structure affect the cost of equity?

A13: Debt holders in a company have a fixed claim on the assets of the company and are paid prior to the company's owners (equity holders), who hold the inherently variable residual claim on the company's operating cash flows. Because equity holders only receive the profit that is left over after the fixed debt payments are made, higher degrees of debt in the capital structure amplify the variability in the expected rate of return earned by equity-holders. This phenomenon of debt resulting in financial leverage for equity holders means that, all else equal, a greater proportion of debt in the capital structure increases risk for equity holders, causing them to require a higher rate of return on their equity investment, even for an equivalent level of underlying business risk.

Q14: How do differences in financial leverage affect the estimation of the cost of equity?

A14: The DCF models and the CAPM rely on market data to estimate the cost of equity for the proxy companies, so the results reflect the value of the capital that investors hold during the estimation period (market values).

The authorized ROE is applied to the regulatory equity portion of CECONY's rate base. Because the cost of equity is measured using a group of proxy companies, it may well be that these companies finance their operations with a different debt and equity proportion than the proportion the Commission allows in CECONY's rate base. Specifically, the DCF models (and the CAPM) measure the cost of equity using market data and consequently are measures of the cost of equity using the proportion of debt and equity that is inherent in that data. Therefore, I consider the impact of any difference between the financial risk inherent in those cost of equity estimates and the capital structure used to determine CECONY's required return on equity.

Differences in financial risk due to the different degree of financial leverage in CECONY's regulatory capital structure compared to the capital structures of the proxy companies mean that the equity betas measured for the proxy companies must be adjusted before they can be applied in determining CECONY's return on equity. Similarly, the cost of equity measured by applying the DCF models to the proxy companies' market data requires adjustment if it is to serve as an estimate of the appropriate allowed ROE for CECONY at the regulatory capital structure the Commission grants.

Importantly, taking differences in financial leverage into account does not change the value of the rate base. Rather, it acknowledges the fact that a higher degree of financial leverage in the regulatory capital structure imposes a higher degree of financial risk for an equity investment in CECONY's rate base than is experienced by equity investors in the market-traded stock of the less leveraged proxy companies.

Q15: How specifically do you consider financial risk in your analysis using market data for the proxy group companies?

A15: The impact of financial risk is taken into account in an analysis of cost of equity using market-based models such as the DCF and CAPM in several ways.[10] One way is to determine the after-tax weighted-average cost of capital for the proxy group using the equity and debt percentages as the weight assigned to the cost of equity and debt. Financial theory holds that for a given level of business risk, the weighted average cost of capital is constant over a broad set of capital structures, i.e., the weighted average cost of capital is the same at, for example, 55 and 45 percent equity, as the cost of equity increases as the percentage of equity decreases. I estimate the weighted cost of capital for each utility in the proxy group based on that utility's capital structure. I then evaluate the average weighted cost of capital across the proxy group. Once the weighted cost of capital is determined for the proxy group, I can

[10] The impact of financial leverage on the risk premium model needs to be considered separately as it uses regulatory data rather than market data, meaning that it is the differences in regulatory capital structures are relevant for this model.

then determine the cost of equity that is required at CECONY's capital structure. This approach assumes that the after-tax weighted average cost of capital is constant for a range that spans the capital structures used to estimate the cost of equity and the regulatory capital structure.

A second approach was developed by Professor Hamada, who estimated the cost of equity using the CAPM and made comparisons between companies with different capital structures using beta. Specifically, in the Hamada approach, I use the estimated beta to calculate what beta would be associated with a 100 percent equity financed firm to obtain a so-called all-equity or assets beta and then re-lever the beta to determine the beta associated with the regulatory capital structure. This requires an estimate of the systematic risk associated with debt (i.e., the debt beta), which is usually quite small. In Exhibit BV-2, I set forth additional technical details regarding the methods that can be used to account for financial risk when estimating the cost of capital.

Q16: Can you provide a numerical illustration of how the cost of equity changes, all else being equal, when the degree of leverage changes?

A16: Yes. I constructed a simple example below, where only the leverage of a company varies. I assumed the return on equity is 11.00 percent at a 50 percent equity capital structure and determine the return on equity that would result in the same overall return if the percentage of equity in the capital structure were reduced to 45 percent.

Figure 3: Illustration of the Impact of Financial Risk on ROE

		Company A (50% Equity)	Company B (45% Equity)
Rate Base	[a]	$1,000	$1,000
Equity	[b]	$500	$450
Debt	[c]	$500	$550
Total Cost of Capital (8%)	[d] = [a] × 8%	$80.0	$80.0
Cost of Debt (5%)	[e] = [c] × 5%	$25.0	$27.5
Equity Return	[f] = [d] - [e]	$55.0	$52.5
Rate of Return on Equity (ROE)	**[g] = [f] / [b]**	**11.00%**	**11.67%**

Figure 3 illustrates how financial risk[11] affects returns and the ROE. The overall return remains the same for Company A and B at $80. But Company B with the lower equity share and higher financial leverage must earn a higher percentage ROE in order to maintain the same overall return. This higher percentage allowed ROE represents the increased risk to equity investors caused by the higher degree of leverage. Importantly, regardless of the equity percentage, customers will pay $80 in capital costs – the only difference between the two companies is how that $80 is sourced between equity and debt holders.

The principle illustrated in Figure 3 is an example of the first adjustment I performed to account for differences in financial risk when conducting estimates of the cost of equity applicable to CECONY.

Q17: Does this approach apply to the risk premium analysis?

A17: Yes, to the extent that there are differences between the capital structures of the companies used to determine the benchmark ROE and CECONY, I need to consider whether I am comparing apples to apples. However, because the allowed ROE usually is applied to book value capital structures, it is the book value capital structure that is relevant for the risk premium method. Further, the average book value capital structure for electric and natural gas utilities for which I have allowed ROE data for, the past has been close to that of CECONY, I do not need to make any adjustments to the estimated ROE. I note, however that for 2021, the average and median allowed equity percentage was 48.5% and 49.8%, respectively for electric utilities and 49.1% and 50.0%, respectively, for natural gas utilities.[12]

C. Approach to Estimating the Cost of Equity

Q18: Please describe your approach for determining the cost of equity for CECONY.

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[11] Financial risk is risk that a company has due to its capital structure; specifically, the higher a company's debt, the larger the financial risk.

[12] S&P Global Market Intelligence, "Rate Case History" Online version as of October 31, 2021.

A18: As stated above, the standard for establishing a fair rate of return on equity requires that a regulated utility be allowed to earn a return equivalent to what an investor could expect to earn on an alternative investment of equivalent risk. Therefore, my approach to estimating the cost of equity for CECONY focuses on measuring the expected returns required by investors to invest in companies that face business and financial risks comparable to those faced by CECONY. Because certain models require market data, my consideration of comparable companies is restricted to those that have publicly traded stock. To this end, I have selected two proxy groups consisting of publicly traded companies. The first proxy group consists of companies providing primarily regulated electric utility services and the second group consists of regulated natural gas distribution utilities.[13] I consider the electric utility, natural gas distribution, and the full samples when deriving estimates of the representative cost of equity according to standard financial models, including two versions of the DCF.

I also perform analyses of historical allowed ROEs for electric and natural gas utilities in relation to prevailing risk-free interest rates at the time the ROE was authorized, and use the implied allowed risk-premium relationship to estimate a utility cost of equity consistent with current economic conditions. The results of this implied risk premium analysis (sometimes referred to herein as the "Risk Premium" model) are an additional consideration that supports my recommendation and serves as a check on the reasonableness of my market-based results.

Q19: How do your approach and models compare with those traditionally employed by the Staff of the New York State Department of Public Service ("Staff")?

A19: As exemplified in recent orders and Commission Staff Testimony regarding the Company's ROE,[14] the Commission's Generic Finance Methodology is broadly similar to, but also has important differences from, my approach.

[13] In addition to the electric sample, I consider a natural gas distribution utility sample (because CECONY is also a natural gas distribution utility).

[14] See, for example, State of New York Public Service Commission, "Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans," Cases 19-E-0065, 19-G-0066, 18-E-0067, 18-G-0068 as well as the "Staff Finance Panel Testimony" in the same proceedings.

The market-based DCF and CAPM estimation techniques I rely on align with the Commission's historical reliance on both DCF and CAPM results to inform its allowed ROE determinations. Of note, Staff has consistently implemented a "zero-beta" version of the CAPM,[15] which is conceptually and methodologically aligned with the version of the empirical CAPM (*i.e.*, ECAPM) that I implement.

While Staff and I both derive estimates from the DCF and CAPM, there are differences in how we select inputs to implement the models. For example, Staff's approach to the DCF attempts to infer a "sustainable growth" rate based on Value Line forecasts of return on book equity and retention ratio, whereas I implement both single- and multi-stage DCF models based directly on forecasts (including by Value Line) of growth in earnings available for distribution to investors. The sustainable growth rate approach has two problems: (i) to my knowledge, there is only one source of forecasted growth (Value Line) and (ii) Value Line's forecasted return on equity and the results obtained from using Value Line's sustainable growth is often inconsistent. It is preferable to use growth rates from multiple sources – IBES growth rates are based on forecasts from many financial analysts. Further, I believe considering the results of both single and multi-stage models is appropriate in light of current market conditions and their impact on dividend yields.

For the CAPM, Staff recently averaged the 10-year and 30-year government bond yield over the most recent three months to obtain an estimate on the risk-free rate,[16] whereas I look at forecasts of the Treasury yield to capture investor expectations for the risk-free rate of return during the period rates set in this proceeding will be in effect. While currently prevailing yields are somewhat lower than the forecasted yield I use, the reverse is true of the market risk premium ("MRP") estimates traditionally relied on by Staff, which are significantly higher than the estimate I employ, which (as discussed below) is supported by both historical and forward-looking evidence. Importantly, the forecasted MRP provides information about the return investors expect going forward and which may differ from the historical average. As discussed below, authors from the Federal Reserve of New York found that following the

[15] "Staff Finance Panel Testimony" in Cases 19-E-0065 & 19-G-0066, p. 141.

[16] "Staff Finance Panel Testimony" in Cases 19-E-0065 & 19-G-0066, p. 95.

financial crisis of 2008-09, the return investors expect increased dramatically and that the effect lingered for serveral years. Given the return on equity determined in this proceeding is expected to be in effect going forward and given that the economy in 2020-21 again has seen substantial disruption, it is reasonable to consider the possibility of an effect similar to that of 2008-09; i.e., that the return investors require in the current economic environment is elevated.

Importantly, as discussed in Section 3.B, my CAPM and DCF analyses employ standard finance techniques to adjust explicitly for differences in financial leverage between the proxy group companies and the Company's requested regulatory capital structure. The fact that Staff's typical approach does not take financial risk into account by using the standard adjustment techniques means that Staff's analysis misses an important step in estimating the opportunity cost of capital commensurate with an investment of equivalent risk.[17]

Finally, in contrast to Staff's practice, I do not believe it is appropriate to place fixed primary emphasis on one model in deriving a recommended allowed ROE. Whereas the Commission has traditionally placed 2/3 weight on the DCF and 1/3 on the CAPM, I consider the ranges of results produced by the models I employ: two versions of the CAPM, two versions of the DCF, and the implied Risk Premium method. The reason I believe it is important to consider the range is that I prefer to focus on the tendency of the data rather than a weighted average of results for two models. Sprecifically, at any given point in time one of the relied upon models may produce less reliable results. For example, if a large number of companies have only a single growth forecast of if it is dated, then the DCF methodology become unreliable. As the U.S. economy continue to be substantially impacted by the ongoing COVID-19 pandemic and utilities' systemic (market) risk have been impacted differently than, for example, the S&P 500,[18] it is not clear that a weighting that was derived years ago still is the best method to determine the ROE that CECONY should be allowed to earn.

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[17] I am not aware of any MBA finance textbooks that do not discuss methods to account for financial risk.

[18] See Section 4.C below for details.

Q20: Why do you believe your approach to considering ranges of estimates derived from multiple versions of both the DCF and CAPM, and also relying on an implied Risk Premium analysis, is justified?

A20: There is no one perfect model for estimating the cost of equity, and the various models and estimation approaches I employ each have different strengths and sensitivities. For example, the CAPM relies on an explicit measurement of systematic risk (beta) for which the cost of equity capital must compensate investors, but this parameter must be measured using historical data,[19] and thus changes more slowly in response to changes in industry risk characteristics. Conversely, the DCF models incorporate current market prices and the most recent dividends, enabling them to capture shifts over time. However, this also makes the DCF sensitive to short-term market phenomena that may or may not be representative of the capital market conditions and required investor returns that will prevail during the time CECONY's electric and gas rates are in effect. In contrast to both the CAPM and DCF models, the implied risk premium analysis focuses directly on the relationship of allowed returns for regulated utility companies to observable rates of return (i.e., bond yields) reflective of contemporaneous capital market conditions.

4. CAPITAL MARKET CONDITIONS AND THE COST OF CAPITAL

Q21: What do you cover in this section?

A21: In this section, I address recent changes in capital market conditions, the increased volatility in equity and debt markets, and how these factors affect the cost of equity and its estimation. Specifically, I address (i) interest rate developments; (ii) investors perception of the market risk premium, and (iii) inflation expectations.[20]

Q22: Why do you discuss capital market conditions in a testimony aimed at determining CECONY's ROE?

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[19] I note that Value Line applies an empirical adjustment (the Blume adjustment) that converts the beta derived from historical return data into a better indicator of forward-looking systematic risk (i.e., a better predictor of beta going forward).

[20] In past testimony, I have discussed utility credit spreads but not inflation. Utility credit spreads are currently only modestly elevated, so I do not attempt to account for this. However, inflation expectations have become a source of substantial concern in recent months and therefore merit consideration.

A22: Capital market conditions are important to cost of equity estimation methodologies and can affect the inputs to the cost of equity models. Inputs to the DCF models are affected by the economy in general as economic growth will affect growth rates and utility stock prices. Consequently, the capital market developments affect the growth rates, dividend yield, and the assessment of estimates' reasonableness.

Furthermore, the risk-free rate is an input to the risk premium model and CAPM, so that recent and expected developments in government bond yields are important to assess the validity of any measure of the risk-free rate. Similarly, the MRP is an input to the CAPM, so factors that affect the MRP (e.g., volatility and changes in investors' risk perceptions) are vital for accurate determination of the ROE. Lastly, inflation has recently been substantially above what the U.S. has become accustomed to and is expected to be above the Federal Reserve's two percent target for a period.[21] Uncertainty about inflation expectations create uncertainty about the cost of capital as well as other aspects of utilities' costs.

Q23: Can you provide a summary of recent events, which have impacted capital market conditions?

A23: Capital markets have seen historic changes since CECONY's last rate case settlement was approved in January 2020.[22] Notably, COVID-19 has emerged as a substantial health risk and responses aimed at containing the virus or stimulating the economy have had a profound impact on financial markets.

In the spring of 2020, a number of states, including New York, implemented emergency measures such as work-from-home mandates and other business restrictions. As a result, economic activity slowed and in March 2020, the S&P 500 dropped by 30%.[23] Unemployment also increased as businesses were closed. In turn, the Federal Reserve cut its target range for the policy rate to 0-0.25 percent and announced unlimited quantitative

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[21] Blue Chip Economic Indicators, October 2021 expects 2022 inflation to be approximately 3.2%.

[22] See also testimony of company witness Saegusa for further discussion on current and expected capital market conditions.

[23] Bloomberg as of October 31, 2021.

easing and emergency liquidity programs to support financial markets.[24] The Federal Government also passed several bills to stimulate the economy. As a result, government bond yields reached historic lows and the economy contracted in the first part of 2020. From an investor perspective, the risks associated with the COVID-19 pandemic and the economic impact thereof resulted in investors requiring a very high premium to hold equity rather than risk-free assets. Additionally, in late 2020 and early 2021, the economy grew substantially with substantial stock market increases, reduction in unemployment and large gross domestic product ("GDP") growth. More recently, the U.S. has seen 30-year high inflation rates and inflation is expected to remain above the targeted level for a period of time. I address these factors and the impact on cost of equity below.

Q24: What do you cover in the remainder of this section?

A24: First, I focus on expected developments in interest rates, which directly impact the cost of equity as estimated by two standard models (the CAPM and risk premium model). Interest rates also may impact indirectly the DCF method as investors' expectations concerning interest rates may impact stock prices and growth. Second, I discuss investor expectations as to the market risk premium, i.e., the return over and above the risk-free rate that investors require to hold equity. This measure again affects the inputs to the financial models and the interpretation of the results. Third, I address the recent changes in electric utilities systematic risk. Fourth, I discuss growth and inflation expectations, which directly affect the DCF model, as well the other models through the expected interest rate developments.

A. Interest Rates

Q25: How do interest rates affect the cost of equity?

A25: The current interest rate environment affects the cost of equity estimation in several ways. Most directly, the CAPM takes as one of its inputs a measure of the risk-free rate.[25] The estimated cost of equity using the CAPM decreases (increases) by one percentage point when

[24] U.S. Federal Reserve, "Federal Reserve Announces Extensive New Measures to Support the Economy," Press Release, March 23, 2020.

[25] See Figure 2.

the risk-free rate decreases (increases) by one percentage point. Therefore, to the extent that prevailing government yields are depressed due to economic uncertainties related to the COVID-19 pandemic or the monetary policy responses, using current yields as the risk-free rate would depress the CAPM estimate below what is representative of the forward-looking cost of equity. Therefore, the allowed fair return on equity for CECONY should reflect the future interest rate environment, specifically the environment at the time the rates being set in this proceeding will be in effect.

Q26: What are the relevant developments regarding interest rates?

A26: Current interest rates on 10-year U.S. Government bonds remain low at 1.58 percent,[26] despite significant improvement since the historic low levels in 2020, due to flight-to-quality behaviors by investors as well as the Federal Reserve's expansion of its quantitative easing programs. Interest rates on 10-year U.S. Government bonds were about 2.6 percent in January 2019 (when Cases 19-E-0065 and 19-G-0066 were filed), 1.7 percent in October 2019 (when the Joint Proposal was submitted) and 1.5 percent in January 2020 (when the Joint Proposal was approved by the Commission).[27] As large parts of the economy began to shut down in response to the pandemic, investors fled riskier assets for safer assets. This demand for U.S. government bonds caused bond yields to decrease rapidly. On March 9, 2020, the entire U.S. yield curve fell below 100 basis points for the first time in history and the 10-year U.S. government bond yield hit a record low of 0.339 percent.[28] Since then, long-term government bond yields have increased somewhat — the yield on 10-year U.S. Government bonds as of October 2021 was 1.55 percent – well below the historical norm.[29]

Looking forward, treasury bonds are forecasted to increase, which is depicted in Figure 4 **Error! Reference source not found.** below. Blue Chip Economic Indicators' ("BCEI") October 2021 edition forecasts that the yield on 10-year treasury bonds will increase.

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[26] Bloomberg as of October 31, 2021.

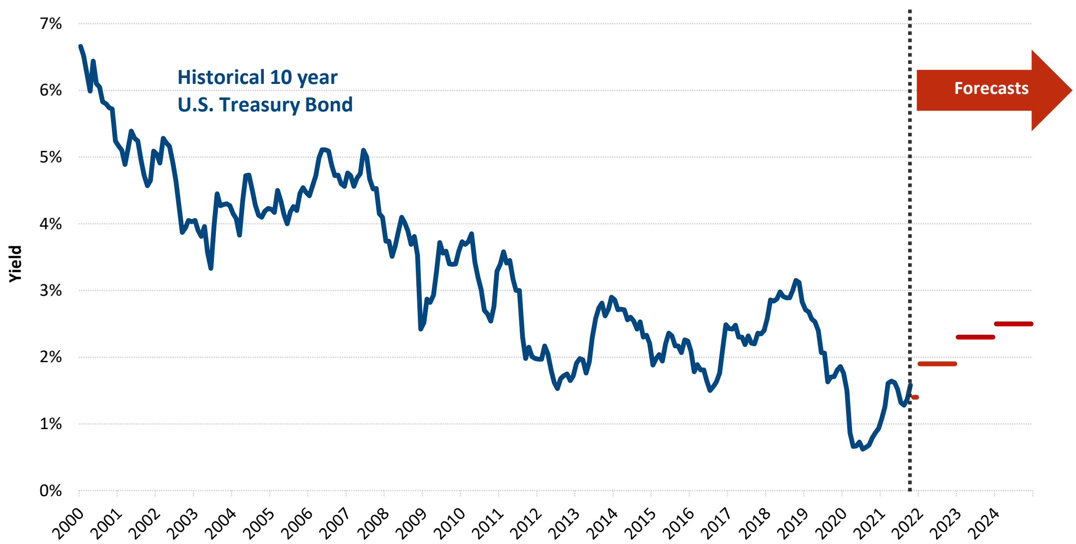
[27] Bloomberg as of October 31, 2021.

[28] Sunny Oh, "Treasury yield curve sinks below 1% after oil and coronavirus worries rout stocks," *Market Watch*, March 9, 2020, accessed March 31, 2020, https://www.marketwatch.com/story/30-year-treasury-yield-tumbles-below-1-after-oil-and-coronavirus-worries-rout-stocks-2020-03-09

[29] Bloomberg as of October 31, 2021.

Specifically, BCEI projects the 10-year government bond yield will be 1.9, 2.3 and 2.5 percent in 2022, 2023 and 2024, respectively (Figure 4**Error! Reference source not found.**).[30] Because the risk-free rate is an input to several cost of equity estimation models, the relationship between current and forecasted risk-free rates is an important consideration.

FIGURE 4: HISTORICAL AND PROJECTED TEN-YEAR TREASURY BOND YIELDS[31]



Source: Historical data from Bloomberg. Forecasts from Blue Chip Economic Indicators October 2021 issue.

The increase in interest rates is consistent with the press release following the most recent meeting of the Federal Reserve, which indicated that the Federal Reserve will decrease its support for treasury bills and bonds,[32] which is what has driven the yield on government bonds down.

Because the government bond yield is forecasted to increase over the period during which CECONY's allowed ROE will be in effect, it is important to use the forecast to determine the cost of equity.[33]

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[30] Wolters Kluwer Blue Chip Economic Indicators October 2021.

[31] Id.

[32] Federal Reserve Board of Governors, "Federal Reserve issues FOCM Statement," December 15, 2021.

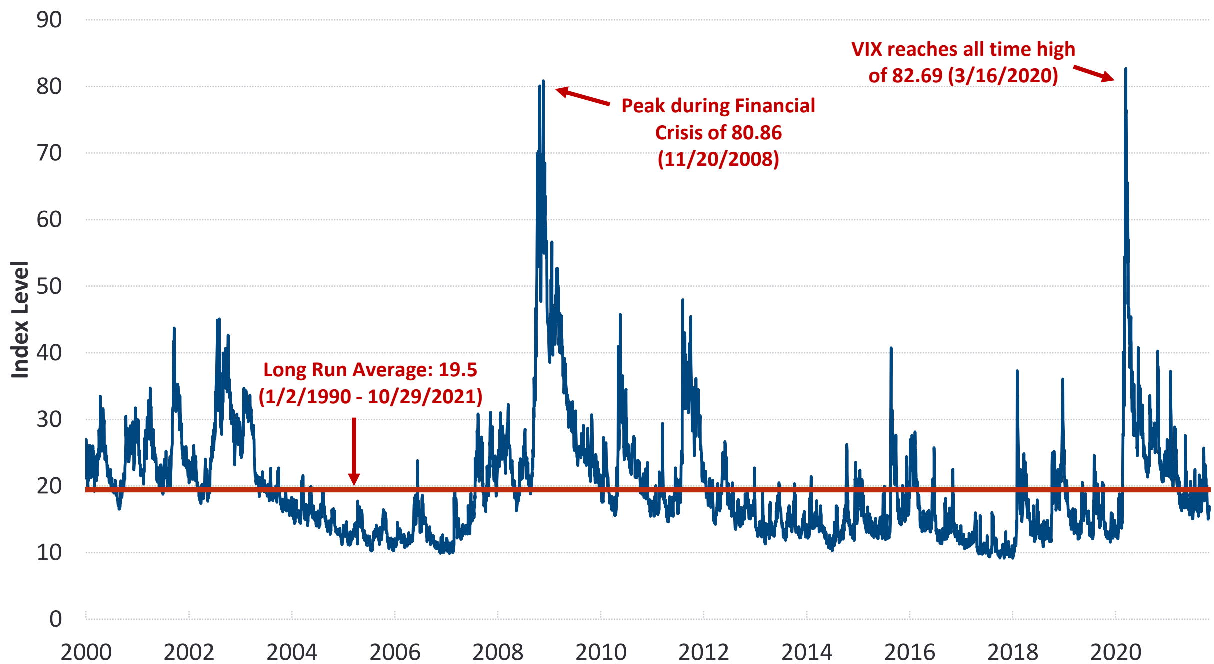
[33] In past cost of capital proceedings, I have considered the spread between utility bond yields and government bond yields to access the need for a normalization of the risk-free rate or an adjustment to the MRP. However, the spread is currently slightly above 100 basis points, which is only slightly above the long run average. Therefore, I do not consider the impact of this spread in this testimony.

B. RISK PREMIUMS

Q27: What is the current evidence regarding market volatility?

A27: During the early months of the COVID-19 pandemic, financial markets became extremely volatile as shown in near-term common volatility measures, such as the VIX, which is frequently referred to as the market's fear index. The VIX reached an all-time high of 82.69 on March 16, 2020, which was higher than the peak of 80.86 during the Financial Crisis. Since then, VIX has remained elevated for some time but has recently returned to its long-term average level of about 20, which is a bit above the pre-COVID-19 pandemic level.[34]

FIGURE 5: VIX: 2000 THROUGH OCTOBER 2021



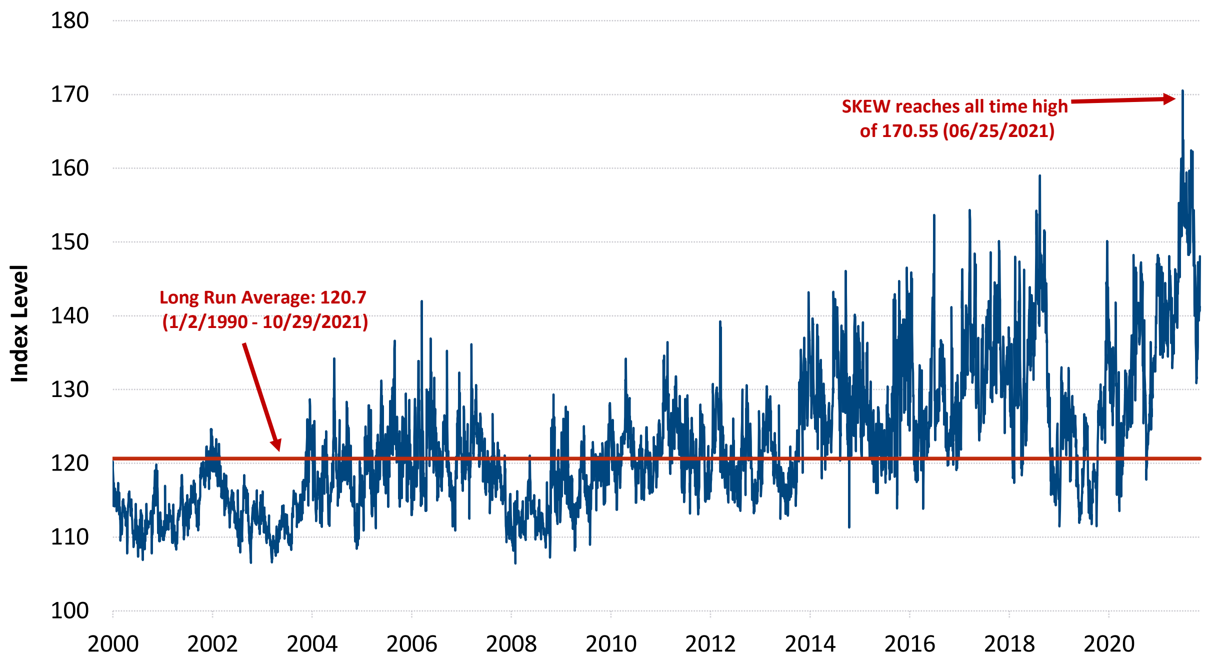
Similarly, the SKEW index, which measures the market's willingness to pay for protection against negative "black swan" stock market events (i.e., sudden substantial downturns),[35] shows that investors are cautious. A SKEW value of 100 indicates outlier returns are unlikely, but as the SKEW increases, the probability of outlier returns becomes more significant. Figure 6 **Error! Reference source not found.** below shows the development in

[34] As of September 30, 2021, the VIX was 23 and as of November 10, 2021 it was 19.

[35] For example, http://www.cboe.com/products/vi5.inde5.volatility/volatility-indicators/skew.

the SKEW since 1990 and that the index has recently increased following a period of declining SKEW. The recent spike in the SKEW shows that investors continue to pay for protection against downside risks.

FIGURE 6: SKEW



As both the VIX and SKEW measures are forward-looking, the variability in VIX and SKEW shows that investors expect volatility to continue (for at least a year) but are cautiously optimistic about investing in equity. The SKEW index spiked over 148.3 on June 30, 2020 and reached its historical high on June 25, 2021 at 170.55—well above the long-term average of 120. It has remained above that level for all of 2021. Such circumstances lead investors to require a higher premium to invest in assets or financial instruments that are not risk-free.

Q28: What is the Market Risk Premium (MRP)?

A28: In general, a risk premium is the amount of "excess" return—above the risk-free rate of return—that investors require to compensate them for taking on risk. As illustrated in Figure

2**Error! Reference source not found.** the riskier the investment, the larger the risk premium investors will require.

The MRP is the risk premium associated with investing in the market as a whole. Since the so-called "market portfolio" embodies the maximum possible degree of diversification for investors,[36] the MRP is a highly relevant benchmark indicating the level of risk compensation demanded by capital market participants. It is also a direct input necessary to estimating the cost of equity using the CAPM and other risk-positioning models.

Q29: Please explain the current evidence related to the MRP.

A29: The heightened volatility in the market has increased the premium that investors require to hold risky assets, especially when measured utilizing forward-looking methodologies that estimate expected market returns with reference to current dividend yields. Bloomberg's forward-looking estimate of the MRP for the U.S. increased to as high as 9.84 percent in March 2020 and remained high at 8.39 percent as of October 2021.[37] The current forward market risk premium investors require to hold risky assets remains substantially elevated compared to both the long-term historical premium and premiums required during pre-pandemic years since capital markets' slow recovery following the financial crisis. Academic research has shown that market disruptions lead to a prolonged MRP impact as discussed below.

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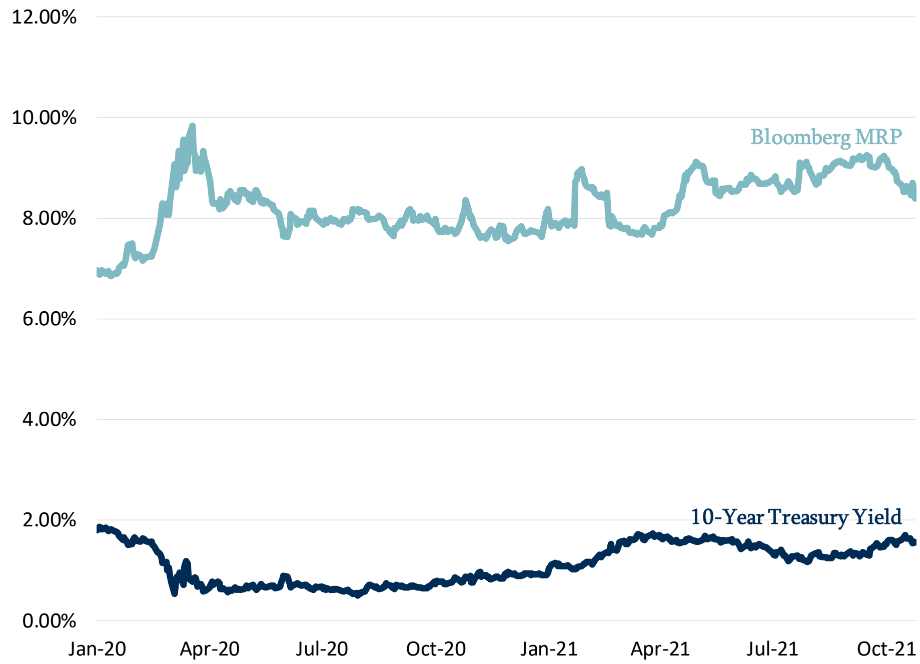
[36] In finance theory, the "market portfolio" describes a value-weighted combination of all risky investment assets (e.g., stocks, bonds, real estate) that can be purchased in markets. In practice, academics and financial analysts nearly always use a broad-based stock market index, such as the S&P 500, to represent the overall market.

[37] Bloomberg, as of October 31, 2021. Measured over a 10-year U.S. Treasury bond.

Figure 7: Bloomberg's Daily Market Risk Premium and Risk-Free Rate (Nov. 2019 – October 2021).



Q30: Are higher risk premiums relevant given that treasuries are near historic lows?

A30: Yes—this is highly relevant for cost of equity estimation, as current risk-free rates are extremely low. As shown in Figure 7 above, the MRP has increased as the risk-free rate declined. Both academic and industry analyses have found that the allowed risk premium over the risk-free rate is inversely related to the risk-free rate. For example, Villadsen, et al. (2017) found that the allowed risk premium increases by approximately 0.44 percent for each 1 percent decline in the risk-free rate for the period 1990 to 2015.[38] Morin finds that the risk premium increases by 0.52 percent for each 1 percent decline in the risk-free rate.[39] This is consistent with Figure 7 above, which focuses on the risk premium for the forward-looking market risk premium calculated by Bloomberg. According to Bloomberg, the MRP is currently 7.89 percent over the 20-year Treasury bond,[40] which is higher than the historical

[38] Bente Villadsen, Michael J. Vilbert, Dan Harris, and A. Lawrence Kolbe, "*Risk and Return for Regulated Industries*," Academic Press, 2017, pp. 118-119.

[39] Roger A. Morin, "*New Regulatory Finance*," Public Utilities Reports, Inc., 2006, pp. 123-125.

[40] Bloomberg, as of October 31, 2021. The 7.89% MRP is relative to the contemporaneous yield over a 20-Yr treasury bond. Relative to the contemporaneous yield over a 10-Yr treasury bond, the Bloomberg reported MRP is 8.39%, which is what Bloomberg reports.

average MRP of about 7.25 percent. It is also an increase over the forward-looking MRPs measured at the end of 2019 (pre-COVID) of 6.48 percent and the approximately 7 percent I reported in the last CECONY rate cases.[41]

Q31: Is there evidence that the MRP will remain elevated going forward?

A31: Yes. In 2015, Duarte and Rose of the Federal Reserve of New York performed a study that aggregated the results of many models of the required MRP in the United States and tracked them over time.[42] This analysis found a very high MRP after the financial crisis, relative to time periods prior the crisis.

The authors estimated the MRP that resulted from a range of models each year from 1960 through the time of their study. The authors then reported the average, as well as the first principal component of the results.[43] The authors found that the models used to determine the risk premium were converging to provide comparable estimates and that the average annual estimate of the MRP had reached an all-time high in 2012-2013. (**Error! Reference source not found.** below is a copy of the summary chart from Duarte and Rosa's 2015 paper). These directional trends identified by Duarte and Rosa are reasonably consistent with those observed from Bloomberg and they further support the proposition that the elevation of the MRP over its historical pre-crisis levels was a persistent feature of capital markets in the time following the financial crisis. Specifically, the financial crisis saw high volatility and a flight to quality – similar to conditions seen in 2020 in response to the COVID-19 pandemic. Therefore, it is reasonable to expect that the current MRP will remain elevated compared to historical levels, especially given the uncertainty related to the extent of economic and financial impacts from the COVID-19 pandemic and the historically low interest rates.

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[41] *Id*.

[42] Fernando Durate and Carlo Rosa, "The Equity Risk Premium: A Review of Models," *Federal Reserve Bank of New York*, December 2015 ("Duarte and Rosa, 2015")

https://www.newyorkfed.org/research/staff_reports/sr714.html.

[43] Duarte and Rosa emphasize the "first principal component" of the 20 models. This means that the authors used statistics to compute the weighted average combination of the models that captures the variability among the 20 models over time.

FIGURE 8: DUARTE AND ROSA'S CHART 3
ONE-YEAR AHEAD MRP AND CROSS-SECTIONAL MEAN OF MODELS

Q32: Please summarize how the economic developments discussed above have affected the return on equity and debt that investors require.

A32: Utilities rely on investors in capital markets to provide funding to support their capital expenditure programs and efficient business operations. Investors consider the risk-return tradeoff in choosing how to allocate their capital among different investment opportunities. It is therefore important to consider how investors view the current economic conditions, including the plausible developments in the risk-free rate and the growth in the U.S. GDP.

These investors have been affected by the recent market volatility, so there are reasons to believe that their risk aversion remains and will remain elevated relative to pre-COVID-19 levels and therefore require will require a higher return. As CECONY is expected to be compensated as a utility on the equity component of its rate base, the same factors would affect CECONY's equity.

C. Utilities Systematic Risk

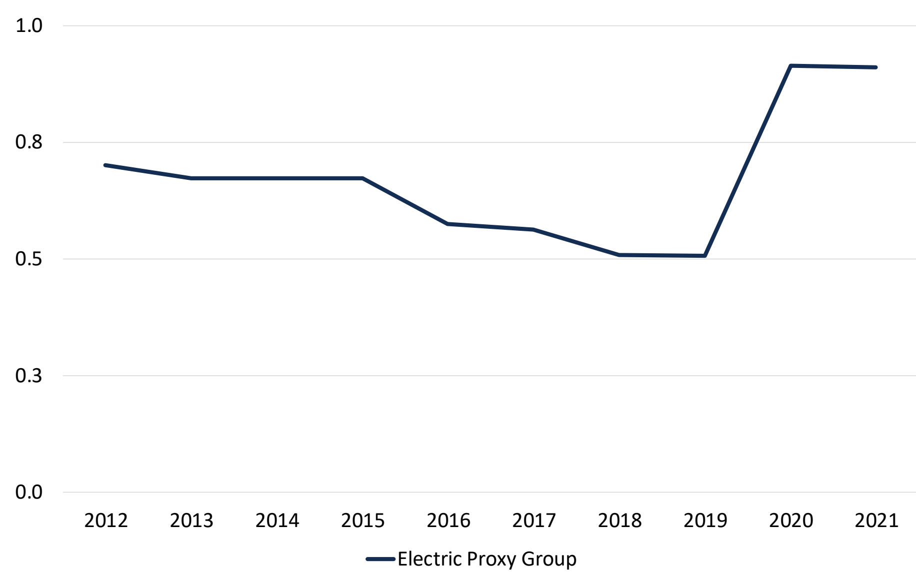
Q33: Are there indications that electric utilities systematic (non-diversifiable) risk has changed?

A33: Yes. The relative risk of electric utilities such as CECONY has increased as demonstrated by the substantial increase in the systematic (non-diversifiable) risk (measured by beta) with electric utilities moving closer to exhibiting risks similar to the market in general as shown in Figure 9 and Figure 10 below. Specifically, the figures below depict the development in

Value Line betas since 2013 (Figure 9) and estimated 3-year weekly betas (Figure 10).[44] Whether I use the Value Line reported beta or estimate betas, the result is clear – the systematic risk of electric utilities has increased. Today's beta of approximately 0.91 for electric utilities is higher than in the past.[45] At the time of the last cost of capital proceeding for CECONY, I found an average Value Line beta of 0.58 and my estimated 3-year beta as of year-end 2019 was below 0.51. The increase in beta is material because a higher beta, all else equal, will lead to a higher cost of equity regardless of the yield on government bonds. Specifically, the risk premium investors require to hold electric utility stock today is higher than at the time of the last cost of capital proceeding. The change in the risk-free rate therefore cannot in and of itself be used to assess the level of or the directional change in the cost of equity. Simply put, other factors influence the cost of equity (e.g., beta and market risk premia) and these factors have moved in a direction that increases the cost of equity.

FIGURE 9

AVERAGE VALUE LINE BETA FOR THE ELECTRIC UTILITY PROXY GROUP OVER TIME

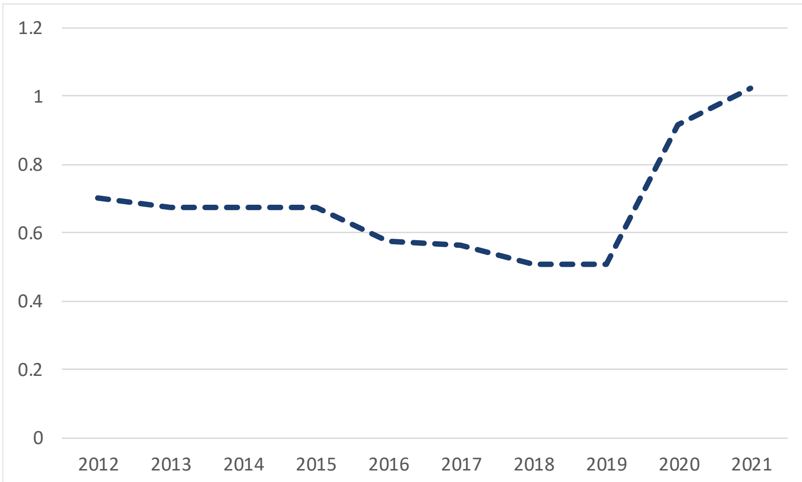


44 3-year weekly betas were estimated using weekly total returns for the electric utilities in my peer group and combining the returns in proportion to the market capitalization. A standard least square regression against the S&P 500 was used.

45 Value Line as of June 30, 2021.

Looking to a more recent measure of systematic risk, Figure 10 shows rolling three-year average betas for the sample of proxy group of electric utilities used to estimate the cost of equity.[46] The most recent measure is 0.90. Figure 9 and Figure 10 are clear indications that the systematic risk of the industry has increased.

FIGURE 10
ROLLING THREE YEAR BETAS[47] OVER TIME



Q34: What conclusions do you draw from the discussion above regarding beta?

A34: Because the utility-specific risk premium is the multiple of the market risk premium and the utility beta, the dramatic increase in beta combined with an increase in the MRP has resulted in a substantially higher utility-specific risk premium. Put simply, the return over and above the risk-free rate that utility investors require has increased and it has increased by more than the risk-free rate has declined since the last CECONY rate cases.

D. INFLATION EXPECTATIONS AND IMPACT

Q35: Why is inflation relevant to the return on CECONY's equity?

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46 Each beta in Figure 10 is calculated as the using weekly data from the prior 156 weeks. The estimate as of year-end 2020 thus uses data for 2018, 2019 and 2020 to calculate the beta estimate. Of note, the estimate for year-end 2021 is 1.0.

47 Rolling 3-year weekly betas calculated per the Value Line method.

A35: The return on equity that is being determined now is expected to be applicable in future years (e.g., 2023 and beyond), so CECONY will be exposed to economic developments over the period for which rates are set. Because the allowed return on equity is a nominal return, it includes today's inflation, but going forward the inflation could readily change. Historically, inflation has impacted not only product prices but also the cost of capital.[48]

Q36: What are recent indicators of the growth and inflation for the US economy?

A36: Recent surveys by economists, such as the BCEI survey, indicate that U.S. real GDP will increase by 4.1% in 2022 and 2.5% in 2023 for a nominal GDP at about 6%, and a bit below 5%, respectively.[49] In August 2020, the U.S. Federal Reserve announced a policy change whereby it would target inflation of 2% on average, noting that the Federal Reserve would hold overnight borrowing interest rates lower for longer.[50] The Federal Reserve has remained cautious about the pace and extent of the ongoing recovery. Until recently, the Federal Reserve indicated that inflation was transitory. For example, in the July 2021 meeting of the FOMC, the FOMC concluded[51]

> *The sectors most adversely affected by the pandemic have shown improvement but have not fully recovered. Inflation has risen, largely reflecting transitory factors.*

And

> *The path of the economy continues to depend on the course of the virus.*

More recently, however, the Federal Reserve as well as other government officials have indicated that inflation may last a bit longer. For example, Mr. Powell's recently stated that he expects inflation will linger "well into next year"[52] and the December 2021 meeting of

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48 For example, the correlation between the allowed ROE and the CPI inflation the prior period since 1992 has been about 34%.

49 Wolters Kluwer Blue Chip Economic Indicators, October 2021, pp. 2-3, 14. As of January 10, 2022, Blue Chip Economic Indicators forecasted the 2022 and 2023 nominal GDP at 8.0 and 5.2 percent, respectively.

50 U.S. Federal Reserve, "Federal Open Market Committee announces approval of updates to its Statement on Longer-Run Goals and Monetary Policy Strategy," August 27, 2020, accessed March 2, 2021, https://www.federalreserve.gov/newsevents/pressreleases/monetary20200827a.htm.

51 Federal Reserve Press Release, July 28, 2021.

52 High Inflation, Falling Unemployment Prompted Powell's Fed Pivot - WSJ

the Federal Board of Governors made clear that the Federal Reserve will reduce its purchases of treasury bills and bonds – i.e., allow prices to decline and yields to increase. These purchases have driven the government issued bond prices up and hence the yield down. Therefore, if inflation expectations changes Federal Reserve policy, it could have a substantial impact on government bond yields.

At the same time, the Federal Government has engaged in substantial fiscal stimulus. For example, since January 2021, several government assistance programs were passed to stimulate the U.S. economy. In early March, the Government passed a $1.9 trillion American Rescue Plan, which provided direct economic impact payments and extended unemployment benefits.[53] More recently, the President signed the $1.2 trillion infrastructure bill into law. The bill allocates funds for infrastructure (including energy) and other items.[54] Other programs, such as the Paycheck Protection Program, continued to disburse aid to businesses. This infusion of cash into the economy has created concerns about inflation.[55]

Following these initiatives, the CPI, a common measure of inflation, increased by 6.8% from November 2020 to November 2021, which is the largest 12-month increase since June 1982.[56] More recently, the December 2021 CPI increase was 7.0 percent.[57] These figures have caused Larry Summers,[58] to warn that "inflation is here" and that a soft landing from inflation is unprecedented.[59] [60] More recently Larry Summers has warned that

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[53] Alan Fram, "Congress Oks $1.9T virus relief bill in win for Biden, Dems," *Associated Press*, March 11, 2021, accessed May 24, 2021, https://apnews.com/article/joe-biden-bills-legislation-coronavirus-pandemic-7eb383e58c8fcf50f6f586b6d5cfc523.

[54] See, for example, Massive Bipartisan Infrastructure Bill Includes Billions in Funding and Process Improvements for Energy and Infrastructure | Publications | Kirkland & Ellis LLP

[55] Federal Reserve Press Release, July 28, 2021.

[56] U.S. Bureau of Labor Statistics, "Economic News Release: Consumer Price Index Summary," December 10, 2021.

Consumer Price Index Summary - 2021 M10 Results (bls.gov)

[57] U.S. Bureau of Labor Statistics, "Economic News Release: Consumer Price Index Summary," accessed Jan. 12, 2022, https://www.bls.gov/news.release/cpi.nr0.htm.

[58] Larry Summers is an economist and a former Secretary of the Treasury (Clinton), Chair of the National Economic Counsel (Obama), Chief Economist at the World Bank, and President of Harvard,

[59] Former Treasury Secretary On Consumer Prices, Inflation, U.S. Role In Global Pandemic Efforts | Here & Now (wbur.org)

[60] WBUR, "Former Treasury Secretary On Consumer Prices, Inflation, U.S. Role in Global Pandemic Efforts," August 11, 2021, https://www.wbur.org/hereandnow/2021/08/11/larry-summers-inflation-prices

> *I don't think we're anywhere close to the kind of Carter-era double-digit inflation, but I do think we're in very serious danger of repeating almost all the mistakes of the 1960s and early 1970s.*[61]

At the same time the Federal Reserve Board in its July meeting stated that "the Committee will aim to achieve inflation moderately above 2 percent for some time so that inflation averages 2 percent over time …"[62] However, Mr. Powell recently stated that he expects inflation will linger "well into next year"[63] and the December 2021 meeting of the Federal Board of Governors made clear that the Federal Reserve will reduce its purchases of treasury bills and bonds – i.e., allow prices to decline and yields to increase. These purchases have driven the government issued bond prices up and hence the yield down. Therefore, if inflation expectations changes Federal Reserve policy, it could have a substantial impact on government bond yields.

Regardless, rising inflation has introduced new uncertainties to the financial markets and points to an increase in the return required by investors to hold risky assets. With the risk of inflation increasing, there is an increased risk that the authorized as well as any currently calculated ROE will be downward biased over the upcoming period.

Finally, although substantial progress has been made on distributing the COVID-19 vaccine, the length and extent of the economic impacts from the COVID-19 pandemic are unknown, and the impacts are expected to persist for some time even as expanded vaccination reduces the risk of spread of COVID-19 and social distancing measures in the US are reduced. In addition, substantial risk remains due to the emergence of the so-called Omicron variant, which, as the Federal Reserve pointed out, means that "[t]he path of the economy continues to depend on the course of the virus."[64]

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[61] Bloomberg Economics, "Summers Sees Dangerous Policy Parallels With High-Inflation Era," September 10, 2021; Summers Sees Dangerous Policy Parallels With High-Inflation Era - Bloomberg

More recently, Larry Summers urged stronger action by the Federal Reserve.

Economist Larry Summers says White House misread inflation | TheHill

[62] Federal Reserve Press Release, July 28, 2021.

[63] Nick Timiraos, "High Inflation, Falling Unemployment Prompted Powell's Fed Pivot," Wall Street Journal, Dec. 6, 2021, https://www.wsj.com/articles/high-inflation-falling-unemployment-prompted-powells-fed-pivot-11638786601.

[64] NPR, "The Fed Says Inflation Is Hotter Than Expected – But It Should Cool Next Year," September 22, 2021; The Fed Says Inflation Is Hotter Than Expected But It Should Cool : NPR

Q37: How do these events impact the cost of equity estimation for CECONY?

A37: The expected interest rate, market risk premium and GDP growth rate directly impact the cost of equity as determined by the CAPM and DCF model. Additionally, inflation expectations and the broader economic conditions affect investors' return and growth expectations. Thus, the factors discussed above impact the cost of equity, which inherently is a forward-looking concept.

5. ESTIMATING THE COST OF EQUITY

A. Proxy Group Selection

Q38: How do you identify proxy companies of comparable business risk to CECONY?

A38: CECONY is primarily engaged in the regulated electric and natural gas distribution business. The business risk associated with these endeavors depends on many factors, including the specific characteristics of the service territory and regulatory environment in which the provider of these services operates. Consequently, it is not possible to identify publicly traded proxy companies that replicate every aspect of CECONY's risk profile. However, selecting companies with business operations concentrated in regulated industries or having similar lines of business and/or business environments is an appropriate starting point for selecting one or more proxy groups of comparable risk to CECONY. As a second step, I must evaluate CECONY, service-territory or New York-specific risks so that the Company's ROE is placed appropriately relative to the sample companies.

To this end, I have selected a sample of electric and natural gas companies. Jointly these companies comprise the "Full Sample." I also report results for the electric utilities that are included in the Full Sample and refer to that sample as the "Electric Sample." I similarly report the results for natural gas utilities that are included in the full sample and refer to that as the "Natural Gas Sample." The proxy companies are similar to CECONY in that they are rate regulated by state utility commissions, provide customers a product through a network of assets, and rely on substantial capital to provide service; i.e., they are capital intensive as is CECONY. Additionally, all regulated utilities are subject to conservation initiatives, many have recently faced moratoriums on shut-offs,[65] and consumption patterns have changed towards residential use during the COVID-19 pandemic period.[66]

It is important that a proxy group used to assess the cost of equity for CECONY (absent of any unique New York or Company characteristics) is regulated, because regulation tends to place substantial requirements and also protections on the companies. I also believe the physical characteristics of the industry – e.g., network, capital intensive, serving different customer groups (residential, commercial, industrial) – is a characteristic of CECONY and of the selected electric and natural gas distribution utilities. The network characteristic implies that assets cannot readily be employed in a different capacity, capital intensity affects the operating risks through the split between fixed and variable costs, and the customer composition affects the demand risk. For example, many electric and natural gas utilities face declining per-customer demand due to conservation and regulation (legislation or voluntary commitments).

Q39: Please summarize how you selected the Electric and Natural Gas samples?

A39: To identify companies suitable for inclusion in the Full Sample, I started with the universe of publicly traded companies in the electric and natural gas utility industry as identified by Value Line Investment Analyzer ("Value Line"). Next, I reviewed business descriptions and financial reports of these companies and eliminated companies that had less than 50 percent of their assets dedicated to regulated utility activities in their industry.[67]

With this group of companies, I applied further screening criteria to eliminate companies that have had recent significant events that could affect the market data necessary to perform cost of capital estimation. Specifically, I identified companies that have cut their dividends or engaged in substantial merger and acquisition ("M&A") activities over the relevant

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[65] Lillian Federico, "Bans on utility shut-offs during COVID-19 pandemic challenge regulators," *S&P Market Intelligence*, August 28, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/blog/bans-on-utility-shut-offs-during-covid19-pandemic-challenge-regulators.

[66] Darren Sweeney, "Warm weather, residential power sales help utilities offset demand declines," *S&P Market Intelligence*, August 4, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/warm-weather-residential-power-sales-help-utilities-offset-demand-declines-59727866

[67] For electric utilities, I rely on Edison Electric Institute (EEI), 2019 Financial Review. This report gives industry financial information as well as a percentage of regulated assets for each of the companies.

estimation window.[68] I eliminated companies with such dividend cuts because the announcement of a cut may produce disturbances in the stock prices and growth rate expectations in addition to potentially being a signal of financial distress. I eliminated companies with significant M&A activities because such events typically affect a company's stock price in ways that are not representative of how investors perceive its business and financial risk characteristics. For example, a utility's stock price will commonly jump upon the announcement of an acquisition to match the acquirer's bid.

Further, I require companies have an investment grade credit rating[69] and more than $300 million in market capitalization to avoid microcap companies. A final, and fundamental, requirement is that the proxy companies have the necessary data available for estimation.

Q40: What are the characteristics of the Electric and Natural Gas Utility samples?

A40: I calculate my results for both the electric proxy group and for the natural gas utility proxy group. The proxy group(s) are comprised of electric and natural gas utilities whose primary source of revenues and majority of assets are subject to regulation. The final proxy group consists of the 27 electric utilities and 8 natural gas utilities listed in Figure 11 and Figure 12 below, respectively.

The figures below report the proxy companies' annual revenues for the most recent four quarters as of 3Q 2021 and also report the market capitalization, credit rating, beta and growth rate. The annual revenue, as well as the market cap, was obtained from Bloomberg. The credit rating is reported by Bloomberg.[70] The growth rate estimate is a weighted average between estimates from Thomson Reuters and *Value Line*. Betas were obtained from *Value Line*.

[68] As described below, the CAPM requires five years of historical data, while the DCF relies on current market data.

[69] In some cases, a proxy company does not have a credit rating from any of the major rating agencies. However, if they were to be rated, they would receive an investment grade rating. In these instances, I assign the company the average credit rating of the rest of the proxy group.

[70] In cases where a company does not have an S&P rating from Bloomberg, Moody's rating was obtained from Moody's, annual reports, or Bloomberg.

Figure 11: Electric Utility Proxy Group

Company	Annual Revenue (Q2 2020) ($MM)	Regulated Assets	Market Cap. (Q3 2021) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
ALLETE	$1,341	MR	$3,200	0.90	BBB	6.6%
Alliant Energy	$3,559	R	$14,457	0.85	A-	5.8%
Amer. Elec. Power	$16,341	R	$42,359	0.75	A-	5.8%
Ameren Corp.	$6,177	R	$21,583	0.85	BBB+	7.3%
Avista Corp.	$1,388	R	$2,817	0.95	BBB	6.9%
Black Hills	$1,873	R	$4,138	1.00	BBB+	4.9%
CMS Energy Corp.	$7,164	R	$17,788	0.80	BBB+	6.1%
CenterPoint Energy	$8,092	R	$15,792	1.15	BBB+	4.2%
Dominion Energy	$13,605	R	$60,572	0.85	BBB+	6.2%
Duke Energy	$24,636	R	$76,655	0.90	BBB+	5.6%
Edison Int'l	$14,731	R	$21,921	1.00	BBB	5.7%
Entergy Corp.	$11,391	R	$21,467	0.95	BBB+	5.7%
Evergy Inc.	$5,559	R	$14,690	0.95	A-	5.0%
Exelon Corp.	$34,833	MR	$48,431	0.95	BBB+	4.4%
Hawaiian Elec.	$2,732	MR	$4,504	0.85	BBB-	1.5%
IDACORP Inc.	$1,439	R	$5,249	0.85	BBB	3.6%
MGE Energy	$581	R	$2,762	0.75	AA-	5.6%
NextEra Energy	$16,418	MR	$160,201	0.95	A-	10.1%
NorthWestern Corp.	$1,339	R	$3,368	0.95	BBB	3.4%
OGE Energy	$3,558	R	$6,780	1.05	BBB+	4.5%
Otter Tail Corp.	$1,090	R	$2,324	0.90	BBB	3.1%
Pinnacle West Capital	$3,746	R	$8,263	0.95	A-	-1.5%
Public Serv. Enterprise	$9,068	MR	$31,055	0.95	BBB+	3.9%
Sempra Energy	$12,184	R	$37,693	1.00	BBB+	16.2%
Southern Co.	$22,463	R	$67,909	0.95	A-	6.9%
WEC Energy Group	$8,048	R	$28,674	0.80	A-	6.7%
Xcel Energy Inc.	$13,023	R	$34,475	0.80	A-	6.7%
Electric Sample	$9,125		$28,116	0.91	BBB+	5.6%

Sources and Notes:
[1]: Bloomberg as of October 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of October 31, 2021.
[6]: See Schedule No. BV-5.

Figure 12: Natural Gas Utility Proxy Group

Company	Annual Revenue (Q2 2020) ($MM)	Regulated Assets	Market Cap. (Q3 2021) ($MM)	Value Line Beta	S&P Credit Rating	Long-Term Growth Estimate
	[1]	[2]	[3]	[4]	[5]	[6]
Atmos Energy	$3,407	R	$11,824	0.80	A-	7.1%
Chesapeake Utilities	$547	R	$2,170	0.80	BBB+	6.1%
New Jersey Resources	$1,992	MR	$3,407	1.00	BBB+	4.9%
NiSource Inc.	$4,702	R	$9,477	0.85	BBB+	8.6%
Northwest Natural	$827	R	$1,455	0.85	BBB+	5.1%
ONE Gas Inc.	$1,699	R	$3,479	0.80	BBB+	4.2%
South Jersey Inds.	$1,838	R	$2,529	1.05	BBB	9.2%
Spire Inc.	$2,273	R	$3,206	0.85	A-	5.7%
Gas Sample	$2,161		$4,693	0.88	BBB+	6.4%
Combined Sample	$2,161		$4,693	0.88	BBB+	6.4%

Sources and Notes:
[1]: Bloomberg as of October 31, 2021.
[2]: Key R - Regulated (80% or more of assets regulated).
MR - Mostly Regulated (less than 80% of assets regulated).
[3]: See Schedule No. BV-3 Panels A through I.
[4]: See Schedule No. BV-10
[5]: Bloomberg as of October 31, 2021.
[6]: See Schedule No. BV-5.

Q41: How do the proxy companies compare to CECONY in terms of financial metrics?

A41: CECONY's regulated electric and gas operations generated an annual revenue of $10,647 million in 2020,[71] which is comparable to that of the electric utility proxy group. CECONY's credit rating is A- and Baa1 from Standard & Poor's and Moody's, respectively, which again is comparable to that of the samples. Lastly, as noted above, CECONY is a regulated distribution company as are all the companies in the natural gas proxy group, while the electric proxy group include a mixture of distribution and vertically integrated electric utilities.

Q42: What regulatory capital structure did you use for CECONY?

A42: As recommended by CECONY Company witness Saegusa, I use a capital structure including 50% equity and 50% debt in my recommendation, which is slightly higher than the capital structure awarded in CECONY's prior rate cases.[72]

[71] Con Edison, Inc. 2020 Annual Report, p. 61.

[72] See testimony of company witness Saegusa.

B. The CAPM Based Cost of Equity Estimates

Q43: Please briefly explain the CAPM.

A43: CAPM assumes the collective investment decisions of investors in capital markets will result in equilibrium prices for all risky assets such that the returns investors expect to receive on their investments are commensurate with the risk of those assets relative to the market as a whole. The CAPM posits a risk-return relationship known as the Security Market Line (see Figure 2 in Section 3), in which the required expected return on an asset (above the risk-free return) is proportional to that asset's relative risk as measured by that asset's beta.

More precisely, the CAPM states that the cost of capital for an investment, S (*e.g.*, a particular common stock), is determined by the risk-free rate plus the stock's systematic risk (as measured by beta) multiplied by the market risk premium. Mathematically, the relationship is given by the following equation:

$$\boldsymbol{r_s = r_f + \beta_s \times MRP} \qquad (1)$$

$\boldsymbol{r_S}$ is the cost of capital for investment S;

- $\boldsymbol{r_f}$ is the risk-free interest rate;
- $\boldsymbol{\beta_S}$ is the beta risk measure for the investment S; and
- $\boldsymbol{MRP}$ is the market equity risk premium.

The CAPM is a "risk-positioning model," which operates on the principle (corroborated by empirical data) that investors price risky securities to offer a higher expected rate of return than safe securities. It says that an investment, whose returns do not vary relative to market returns, should receive the risk-free interest rate (that is the return on a zero-risk security, the y-axis intercept in Figure 2), whereas investments of the same risk as the overall market (*i.e.*, those that by definition have average systematic market risk) are priced so as to expect to return the risk-free rate plus the MRP. Further, it says that the risk premium of a security over the risk-free rate equals the product of the beta of that security and the MRP.[73]

[73] Of note, empirical evidence indicates that the CAPM estimates are too low for smaller companies such as CECONY. For example, Duff & Phelps provide an adder for companies by size. While I do not provide a size adder, regulators such as the Federal Energy Regulatory Commission do add a premium to smaller companies cost of equity.

1. Inputs to the CAPM

Q44: What inputs does your implementation of the CAPM require?

A44: As demonstrated by equation (1), estimating the cost of equity for a given company requires a measure of the risk-free rate of interest and the MRP, as well as a measure of the stock's beta. There are several choices and sources of data that inform the selection of these inputs. I discuss these issues below. (Additional technical detail, along with a discussion of the finance theory underlying the CAPM is provided in Exhibit BV-2).

Q45: What value did you use for the risk-free rate of interest?

A45: I use the yield on a 20-year U.S. Treasury bond as the risk-free rate for purposes of my analysis. Recognizing the fact that the cost of capital set in this proceeding will be in effect starting 2022 and through 2024, I rely on a forecast of the average Government bond yields in the rate period. In October 2021, the BCEI survey estimated the average 10-year U.S. Treasury bond yields between 2022 and 2024 will be 2.23%.[74] I then adjust this value upwards by 50 basis points to reflect the historical maturity premium for the 20-year U.S. Treasury bond yield over the 10-year U.S. Treasury bond yield.[75] This gives me a risk-free rate of 2.73%.

Q46: What value did you use for the MRP?

A46: Like the cost of capital itself, the MRP is a forward-looking concept. It is by definition the premium above the risk-free interest rate that investors can expect to earn by investing in a value-weighted portfolio of all risky investments in the market. The premium is not directly observable. Rather, it must be inferred or forecasted based on known market information. One commonly used method for estimating the MRP is to measure the historical average premium of market returns over the income returns on government bonds a long historical

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[74] Wolters Kluwer Blue Chip Economic Indicators and PwC Analysis, Consensus Forecasts, October 2021, p. 14.

[75] This maturity premium is estimated by comparing the average excess yield on 20-year versus 10-year U.S. Treasury bonds over the period 1990-2020, using data from Bloomberg.

period.[76] The average market risk premium from 1926 to the present (2020) is 7.25 percent.[77] I use this value of the MRP along with a risk-free rate of 2.73% in one of my CAPM scenarios.

However, investors may require a higher or lower risk premium, reflecting the investment alternatives and aggregate level of risk aversion at any given time. As explained in Section 4, there is evidence that investors' level of risk aversion is elevated relative to the time before the COVID-19 pandemic and may remain elevated for some time, even after the pandemic. In recognition of the evidence that forward-looking measures of expected market equity risk premium are higher than the long-term historical average, I also perform a CAPM calculation using Bloomberg's forecasted MRP of 7.89 percent.[78]

Q47: Please summarize the parameters of the scenarios and variations you considered in your CAPM and ECAPM analyses.

A47: The parameters are displayed in Figure 13 below. In my CAPM and ECAPM analyses, I consider two sets of scenarios based on the empirical observation that the yield spread is higher than normal as is the forecast MRP, as discussed above in Section 4. The increase yield spreads could reflect the increase in MRP or downward pressure on the yield of government bonds due to monetary policy and flight-to-quality behaviors. Therefore, I use an unadjusted historic average MRP with the increased estimate of the risk-free rate in one scenario; whereas, in the second scenario I use an unadjusted forecasted risk-free rate with a higher estimate of the MRP. To be conservative, I do not simultaneously normalize the risk-free rate and elevate the MRP.

Scenario 1 uses an unadjusted risk-free rate based on the forecasted 20-year U.S. Treasury rate for 2021 of 2.73%. I pair this with the long-term average historic MRP of 7.25% as estimated by Duff & Phelps.

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[76] The longest period for which Duff & Phelps reports data is 1926 to current. Based on financial textbooks such as Ross, Westerfield and Jaffe, "*Corporate Finance*," 10'th Edition, 2013, pp. 324-327, I use the longest period for which reliable estimates are available – in this case 1926 to 2020.

[77] Duff & Phelps, *Ibbotson SBBI 2020 Valuation Yearbook* 10-21.

[78] Bloomberg as of October 31, 2021.

In my second scenario, I use an unadjusted risk-free rate based on the forecasted 20-year U.S. Treasury rate for 2021 of 2.73%. I then use Bloomberg's forecasted MRP of 7.89%.[79]

Figure 13: CAPM and ECAPM Scenarios

	Scenario 1	Scenario 2
Risk-Free Interest Rate	2.73%	2.73%
Market Risk Premium	7.25%	7.89%

Q48: What betas did you use for the companies in your proxy groups?

A48: I used *Value Line* betas, which are estimated using the most recent five years of weekly historical returns data.[80] The *Value Line* levered equity betas are reported in Figure 11 above. Importantly, these betas—which are measured (by *Value Line*) using the market stock return data of the proxy companies—reflect the level of financial risk inherent in the proxy companies' market value leverage ratios over the estimation period. Because CECONY's regulatory capital structure includes a substantially higher proportion of debt financing than does the market data on the proxy companies used to estimate the ROE[81], the financial risk associated with an equity investment in CECONY's rate base is correspondingly greater than the financial risk borne by investors in the proxy companies' publicly traded stock. Importantly, the DCF model and the CAPM-based models use market data to estimate the ROE, so that it is the market value capital structure that is the relevant comparison across companies. As the risk premium model's ROE estimates are based on book value capital structures, the relevant comparison is across book value capital structures for that model.

[79] Calculated as the Bloomberg forecasted MRP of 8.39% minus the spread between the yield on a 20-year and a 10-year government bond as Bloomberg measures the MRP over 10-year yields, while I rely on 20-year yields.

[80] See Value Line Glossary, accessible at http://www.valueline.com/Glossary/Glossary.aspx

[81] CECONY's proposed regulatory debt ratio of 50% is significantly above the average five-year average debt ratio measured for the Electric and Natural Gas Proxy Groups. The average debt percentages of the Electric and Natural Gas proxy groups over the past five years are 39% and 38%, respectively. As of October 31, 2021, the Electric and Natural Gas proxy groups average debt percentages are 43% and 47%, respectively.

Consequently, standard textbook techniques are applied to unlever the *Value Line* betas reported in Figure 11 above and relever the resulting asset betas at CECONY's regulatory capital structure. See Exhibit BV-3, Tables BV-13 to BV-15.[82]

2. The Empirical CAPM

Q49: What other equity risk premium model do you use?

A49: Empirical research has long shown that the CAPM tends to overstate the actual sensitivity of the cost of capital to beta: low-beta stocks tend to have higher risk premiums than predicted by the CAPM and high-beta stocks tend to have lower risk premiums than predicted.[83] A number of variations on the original CAPM theory have been proposed to explain this finding, but the observation itself can also be used to estimate the cost of capital directly, using beta to measure relative risk by making a direct empirical adjustment to the CAPM.

The second variation on the CAPM that I employ makes use of these empirical findings. It estimates the cost of capital with the equation,

$$\boldsymbol{r_S = r_f + \alpha + \beta_S} \times (\boldsymbol{MRP - \alpha}) \qquad (2)$$

where $\boldsymbol{\alpha}$ is the "alpha" adjustment of the risk-return line, a constant, and the other symbols are defined as for the CAPM (see equation (2) above).

I label this model the Empirical Capital Asset Pricing Model, or "ECAPM." The alpha adjustment has the effect of increasing the intercept but reducing the slope of the Security Market Line in Figure 2, which results in a Security Market Line that more closely matches the results of empirical tests. This adjustment is portrayed in Figure 14 below. In other words,

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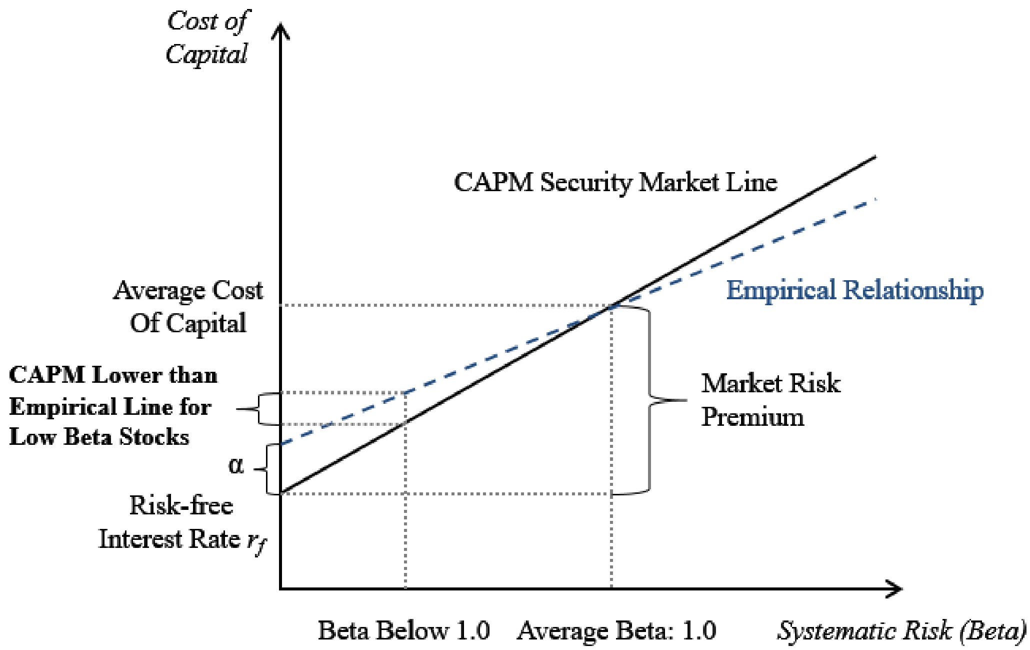
[82] The Technical Appendix (Exhibit BV-2) to this testimony provides a detailed description of the standard textbook formulas used to implement the "Hamada" technique for unlevering measured equity betas based on the proxy companies' capital structures to calculate "asset betas" that measure the proxy companies' business risk independent of the financial risk impact of differing capital structures. The proxy group average asset betas are then relevered at the target capital structure (i.e., CECONY's regulatory capital structure), with the precise relevered beta depending on the specific version of the unlevering/relevering formula employed.

[83] *See* Figure A-2 in Exhibit BV-2 for references to relevant academic articles.

the ECAPM produces more accurate predictions of eventual realized risk premiums than does the CAPM.

Figure 14: The Empirical Security Market Line



Q50: Why do you use the ECAPM?

A50: Academic research finds that the CAPM has not generally performed well as an empirical model. One of its shortcomings is directly addressed by the ECAPM, which recognizes the consistent empirical observation that the CAPM underestimates the cost of capital for low beta stocks. In other words, the ECAPM is based on recognizing that the actual observed risk-return line is flatter and has a higher intercept than that predicted by the CAPM. The alpha parameter (α) in the ECAPM adjusts for this fact, which has been established by repeated empirical tests of the CAPM. In summary, these studies estimate alpha parameters that range between 1%[84] and 7.32%.[85] I apply an alpha parameter of 1.5% in my application

[84] Black, Fischer. Beta and Return. *The Journal of Portfolio Management* 20 (Fall): 8-18.

[85] Eugene F. Fama and Kenneth R. French. 1992. The Cross-Section of Expected Stock Returns. *Journal of Finance* 47 (June): 427-465.

of the ECAPM. Exhibit BV-2 provides further discussion of the empirical findings that have tested the CAPM and also provides documentation for the magnitude of the adjustment, α.

3. Results from the CAPM Based Models

Q51: Please summarize the results of the CAPM-based models.

A51: The results of CAPM and ECAPM estimation for the three proxy groups are presented in Figure 15 below. The ranges of results for each model (CAPM and ECAPM) reflect the application of different specific versions of the textbook formulas used to account for the impact of different financial leverage on financial risk.

Figure 15: CAPM and ECAPM Summary at 50% Equity Capital Structure

Estimated Return on Equity	Scenario 1 [1]	Scenario 2 [2]
Electric Sample		
Financial Risk Adjusted Method		
CAPM	10.8%	11.5%
ECAPM (α = 1.5%)	11.0%	11.7%
Hamada Adjustment Without Taxes		
CAPM	10.7%	11.4%
ECAPM (α = 1.5%)	10.6%	11.3%
Hamada Adjustment With Taxes		
CAPM	10.4%	11.1%
ECAPM (α = 1.5%)	10.3%	11.0%
Gas Sample		
Financial Risk Adjusted Method		
CAPM	10.7%	11.4%
ECAPM (α = 1.5%)	11.0%	11.6%
Hamada Adjustment Without Taxes		
CAPM	10.6%	11.3%
ECAPM (α = 1.5%)	10.5%	11.2%
Hamada Adjustment With Taxes		
CAPM	10.3%	10.9%
ECAPM (α = 1.5%)	10.2%	10.9%

Sources and Notes:
[1]: Long-Term Risk Free Rate of 2.73%, Long-Term Market Risk Premium of 7.25%.
[2]: Long-Term Risk Free Rate of 2.73%, Long-Term Market Risk Premium of 7.89%.

Q52: How do you interpret the results of your CAPM and ECAPM Analyses?

A52: The results in Figure 15 above range from 10.2% to 11.7% with the majority of the results in the range of 10.25 to 11.25 percent.[86] As I discussed above, the established academic evidence indicates that the traditional CAPM tends to underestimate the cost of equity for lower-than-average risk companies, such as the electric and natural gas utilities in Figure 11, so the ECAPM results are more reliable and the CAPM results are conservative. I also note that the CAPM may under-estimate the cost of equity for smaller companies such as CECONY. As a result, I consider a reasonable range of 10.25 to 11.25 percent for both the electric and the natural gas sample and the overall recommendation of 10.0 to 10.5 percent is conservative.

C. DCF Based Estimates

Q53: Please describe the DCF model's approach to estimating the cost of equity.

A53: The DCF model attempts to estimate the cost of capital for a given company directly, rather than based on its risk relative to the market as the CAPM does. The DCF method assumes that the market price of a stock is equal to the present value of the dividends that its owners expect to receive. The method also assumes that this present value can be calculated by the standard formula for the present value of a cash flow—literally a stream of expected "cash flows" discounted at a risk-appropriate discount rate. When the cash flows are dividends, that discount rate is the cost of equity capital:

$$\boldsymbol{P_0 = \frac{D_1}{1+r} + \frac{D_2}{(1+r)^2} + \frac{D_3}{(1+r)^3} + \cdots + \frac{D_T}{(1+r)^T}} \qquad (3)$$

Where,

$\boldsymbol{P_0}$ is the current market price of the stock;

$\boldsymbol{D_t}$ is the dividend cash flow expected at the end of period $\boldsymbol{t}$;

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[86] I round to the nearest 0.25 percent when determining ranges of reasonable results. There are numbers below 10.25 percent and above 11.25 percent in Figure 15, but if rounding to the nearest 0.25 percent, I have a small number of observations above and below the range. I focus on the results obtained from the Hamada approach. I round to the nearest 0.25 percent because the cost of capital cannot, in my opinion, be determined with greater precision.

$\boldsymbol{T}$ is the last period in which a dividend cash flow is to be received; and

$\boldsymbol{r}$ is the cost of equity capital.

Importantly, this formula implies that if the current market price and the pattern of expected dividends are known, it is possible to "solve for" the discount rate r that makes the equation true. In this sense, a DCF analysis can be used to estimate the cost of equity capital implied by the market price of a stock and market expectations for its future dividends.

Many DCF applications assume that the growth rate lasts into perpetuity, so the formula can be rearranged algebraically to estimate directly the cost of capital. Specifically, the implied DCF cost of equity can then be calculated using the well-known "DCF formula" for the cost of capital:

$$\boldsymbol{r = \frac{D_1}{P_0} + g = \frac{D_0}{P_0} \times (1 + g) + g} \qquad (4)$$

where $\boldsymbol{D_0}$ is the current dividend, which investors expect to increase at rate $\boldsymbol{g}$ by the end of the next period, and over all subsequent periods into perpetuity.

Equation (4) says that if equation (3) holds, the cost of capital equals the expected dividend yield plus the (perpetual) expected future growth rate of dividends. I refer to this as the single-stage DCF model; it is also known as the Gordon Growth model, in honor of its originator, Professor Myron J Gordon.

Q54: Are there other versions of the DCF model?

A54: Yes. There are many alternative versions, notably (i) multi-stage models, (ii) models that use cash flow rather than dividends, or versions that combine aspects of (i) and (ii).[87] One such alternative expands the Gordon Growth model to three stages. In the multistage model,

[87] The Surface Transportation Board uses a cash flow based model with three stages. See, for example, Surface Transportation Board Decision, "STB Ex Parte No. 664 (Sub-No. 1)," Decided January 23, 2009. Confirmed in STB EP No. 664 (Sub-No. 4), decided 23, 2020.

earnings and dividends can grow at different rates, but must grow at the same rate in the final, constant growth rate period. [88]

In my implementation of the multi-stage DCF, I assume that companies grow their dividend for five years at the forecasted company-specific rate of earnings growth, with that growth then tapering over the next five years toward the growth rate of the overall economy (i.e., the long-term GDP growth rate forecasted to be in effect ten years or more into the future).

1. DCF Inputs and Results

Q55: What growth rate information do you use?

A55: The first step in my DCF analysis (either constant growth or multi-stage formulations) is to examine a sample of investment analysts' forecasted earnings growth rates for companies in my proxy group. For the single-stage DCF and for the first stage of the multi-stage DCF, I use investment analyst forecasts of company-specific growth rates sourced from *Value Line* and Thomson Reuters *IBES*.

For the long-term growth rate for the final, constant-growth stage of the multistage DCF estimates, I use the long-term U.S. GDP growth forecast of 4.0 from Blue Chip Economic Indicators.[89] Thus, the long-run (or terminal) growth rate in the multi-stage model is nominal GDP growth.

Additionally, I relied on the dividend yield of the companies, which I estimate using the most recently available dividend information (currently) and the average of the last 15 days of stock prices ending October 29, 2021. As the single largest advantage of the DCF model is that it uses current market information, I find it is important to use a relatively short time period to determine the dividend yield – yet to avoid the bias caused by any one day. I

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[88] See Exhibit BV-2 for further discussion of the various versions of the DCF model, as well as the details of the specific versions I implement in this proceeding.

[89] See Blue Chip Economic Indicators, October 2021, p. 15.

believe a 15-day average accomplishes that goal. Because some companies engage in share buybacks,[90] the dividend yield may underestimate the yield on cash distributions to investors.

Q56: Please explain how input data can affect the DCF models.

A56: The Gordon Growth/single-stage DCF models require forecast growth rates that reflect investor expectations about the pattern of dividend growth for the companies over a sufficiently long horizon, but estimates are typically only available for 3-5 years.

One issue with the data is that it includes solely dividend payments as cash distributions to shareholders, while some companies also use share repurchases to distribute cash to shareholders. To the extent that companies in my samples use share repurchases, the DCF model using dividend yields will underestimate the cost of equity for these companies. While there are companies in my sample that have engaged in share buybacks in the past, the magnitude is currently not large.

A second issue is that the flight to quality has resulted in higher than usual stock prices for electric and natural gas utilities and hence lower than usual dividend yields. As a result, the dividend yield may be downward biased. The multi-stage DCF model additionally requires a measure of the long-term GDP growth.

Q57: Please summarize the DCF-based cost of equity estimates for the proxy groups.

A57: The results of the DCF based estimation for the proxy groups are displayed below in Figure 16.

[90] For example, in the electric utility sample Dominion Energy is engaged in a share buyback program; Dominion Energy, "Dominion Energy Provides Update on Closing of Gas Transmission, Storage Assets Sale and Status of Share Repurchases," Press Release, September 30, 2020.

Figure 16: DCF Model Results at 50% Equity Capital Structure

	Simple	Multi-stage
	[1]	[2]
Electric Sample	10.4%	8.7%
Gas Sample	10.4%	8.5%
Full Sample	10.4%	8.6%

Q58: How do you interpret the results of your DCF Analyses?

A58: The DCF model estimates presented in Figure 16 exhibit a range from 8.5% to 10.4%. As discussed above, there are unprecedented changes occurring in financial markets and electric and gas utilities systematic risk has increased. When market prices fall (increase), dividend yields increase (fall) and result in an increased (decreased) cost of equity. However, the DCF model requires forecasted growth rates that are based on stable economic conditions to satisfy the constant dividend growth assumption. Growth rates may also be slower than dividend yields to reflect market uncertainty. Consequently, I symmetrically narrow the range from the estimated 8.5% to 10.5% (rounding to the nearest ¼ percent) to 9 to 10 percent, but note that the upper end is consistent with the CAPM results.

D. Risk Premium Model Estimates

Q59: Did you estimate the cost of equity that results from analysis of risk premiums implied by allowed ROEs in past utility rate cases?

A59: Yes. In this type of analysis, sometimes called the “risk premium model,” the cost of equity capital for utilities is estimated based on the historical relationship between allowed ROEs in utility rate cases and the risk-free rate of interest at the time the ROEs were granted. These estimates add a “risk premium” implied by this relationship to the relevant (prevailing or forecast) risk-free interest rate:

$$Cost\ of\ Equity = r_f + Risk\ Premium \quad (5)$$

Q60: What are the merits of this approach?

A60: First, it estimates the cost of equity from regulated entities as opposed to holding companies, so that the relied-upon figure is directly applicable to a rate base. Second, the allowed returns are readily observable to market participants, who will use this one data input in making investment decisions, so that the information is at the very least a good check on whether the return is comparable to that of other investments. Third, I analyze the spread between the allowed ROE at a given time and the then-prevailing interest rate to ensure that I properly consider the interest rate regime at the time the ROE was awarded. This implementation ensures that I can compare allowed ROE granted at different times and under different interest rate regimes.

Q61: How did you use rate case data to estimate the risk premiums for your analysis?

A61: The rate case data from 1990 through Q3 2020 is derived from Regulatory Research Associates.[91] Using this data I compared (statistically) the average allowed rate of return on equity granted by U.S. state regulatory agencies in electric utility rate cases to the average 20-year Treasury bond yield that prevailed in each quarter.[92] I calculated the allowed utility "risk premium" in each quarter as the difference between allowed returns and the Treasury bond yield, since this represents the compensation for risk allowed by regulators. Then I used the statistical technique of ordinary least squares ("OLS") regression to estimate the parameters of the linear equation:

$$Risk\ Premium = A_0 + A_1 \times (Treausury\ Bond\ Yield) \tag{6}$$

I derived my estimates of A_0 and A_1 using standard statistical methods (OLS regression) and found that the regression has a high degree of explanatory power in a statistical sense. I report my results for the respective classifications of rate cases below in Figure 17.[93] I note that the results displayed in Figure 17 below show that the risk premium model fits the data well as

[91] S&P Market Intelligence, as of October 2020.

[92] I rely on the 20-year government bond to be consistent with the analysis using the CAPM to avoid confusion about the risk-free rate. While it is important to use a long-term risk-free rate to match the long-lived nature of the assets, the exact maturity is a matter of choice.

[93] Exhibit BV-3, Table No. BV-16 contains my risk premium analysis.

the R-squared is above 0.87 and R-squared is a measure of how well the data fits the model. An R-squared above 0.8 indicates a solid result.

Figure 17: Implied Risk Premium Model Estimates: Electric Utilities

	R Squared	Estimate of Intercept (A0)	Estimate of Slope (A1)	Implied Cost of Equity Range
	[1]	[2]	[3]	[4]
Electric Utility	86.1%	8.5%	-55.3%	9.8%

Sources and Notes:
[1]-[3]: Estimated Using S&P Market Intelligence, as of October 2021
[4]: Risk-free rate of 2.73%

Figure 18: Implied Risk Premium Model Estimates: Natural Gas Utilities

	R Squared	Estimate of Intercept (A0)	Estimate of Slope (A1)	Implied Cost of Equity Range
	[1]	[2]	[3]	[4]
Gas Utility	88.5%	8.6%	-57.0%	9.7%

Sources and Notes:
[1]-[3]: Estimated Using S&P Market Intelligence, as of October 2021
[4]: Risk-free rate of 2.73%

Q62: What conclusions did you draw from your risk premium analysis?

A62: The results in Figure 17 and Figure 18 indicate a ROE of 9.8 percent for an average electric utility and a ROE of 9.7% for an average natural gas utility based on the risk premium model, which is consistent with the reasonable range of CAPM and DCF estimates. While the risk premium model is based on historical allowed returns and not underpinned by fundamental financial principles in the manner of the CAPM and DCF models, I believe that this analysis, when properly designed, executed, and placed in the proper context, is a valid and useful approach to estimating utility ROEs. Because the risk premium analysis as implemented considers the interest rate prevailing during the quarter the decision that granted an ROE used in the analysis was issued, it provides a useful benchmark for the cost of equity in any interest environment. Because it relies on the returns for regulated utilities, I believe this method provides a good way to directly assess whether the ROE is commensurate with that available to alternative regulated investments of similar risk.

E. Summary of Results

Q63: Please summarize your results before considering where to place CECONY.

A63: Assuming a 50% equity capital structure for CECONY, I find the reasonable range of ROE results displayed in Figure 19. Next, I consider CECONY and New York specific risks to inform my recommendation of a reasonable ROE for CECONY.

Figure 19: Summary of Reasonable Ranges at 50% Equity

	Electric Sample	Gas Sample	Full Sample
CAPM/ ECAPM	10.25% - 11.25%	10.25% – 11.25%	10.25-% - 11.25%
DCF	9.0% - 10.0%	9.0% - 10.0%	9.0% - 10.0%
Risk Premium	9.8%	9.7%	9.7% – 9.8%

6. CECONY SPECIFIC CIRCUMSTANCES

A. Business Risk Characteristics

Q64: How does the regulatory environment in which CECONY operate compare with the environments of the other sample companies?

A64: The details of New York regulation are discussed in the testimony of Company Witness Saegusa. I note two key developments: (i) proposed changes to regulatory oversight leading to S&P Global Ratings putting Consolidated Edison on negative outlook and (ii) the Climate Leadership and Community Protection Act ("CLCPA"), which adopts aggressive targets related to greenhouse gas ("GHG") reduction and clean energy targets for the state of New York. I address each of these below.

Q65: Please explain the reactions to the changes in the regulatory environment and the impact on CECONY.

A65: In response to the proposed changes to regulatory oversight and potential fines announced by the former New York Governor in 2020, S&P Global Ratings put Consolidated Edison, Inc. and its subsidiaries on negative credit outlook.To the extent that regulatory independence risks continue to materialize, S&P notes that it could increase Con Edison, Inc.'s business risk assessment, which would likely lead to a credit downgrade given the company's current FFO to debt of approximately 16%.The impact on CECONY's credit measures is discussed in detail in Company Witness Saegusa' testimony.

Q66: How have recent energy and climate policies impacted the business risk of CECONY's gas utility operations?

A66: New York State also recently passed the Climate Leadership and Community Protection Act ("CLCPA"), which adopts aggressive targets related to greenhouse gas ("GHG") reduction and clean energy targets.[94] Specifically, the CLPCA requires the State to reach a 70% renewable energy target by 2030 and then a carbon-free electricity system by 2040. The CLPCA also mandates a reduction in GHG emissions by 85% below 1990 levels by 2050.[95]

For CECONY's natural gas operations, the emphasis on decreasing carbon emissions and transitioning to a carbon neutral system creates some uncertainty about CECONY's future gas demand. At the same time, there are substantial efforts to increase non-carbon heating through, for example, incentives for heat pump installation, which will reduce the amount of gas (and/or oil) used for heating.[96] The general uncertainty surrounding the future of CECONY's gas business in New York increases the Company's business risk, but may have a load increasing effect on its electric business. The key point is that the uncertainty that surrounds the implementation of the CLCPA increases CECONY's business risk.

[94] New York State, "Governor Cuomo Executives the Nation's Largest Offshore Wind Agreement and Signs Historic Climate Leadership and Community Protection Act," July 18, 2019, https://www.governor.ny.gov/news/governor-cuomo-executes-nations-largest-offshore-wind-agreement-and-signs-historic-climate.

[95] Ibid.

[96] For example, CECONY offers residential customers rebates for installing heat pumps. https://www.oru.com/en/save-money/rebates-incentives-credits/rebates-incentives-tax-credits-for-residential-customers/clean-heating-cooling-with-heat-pumps.

Q67: How does the use of regulatory mechanisms in the state of New York compare to those of the comparable companies?

A67: Looking to the list of commonly used regulatory mechanisms, I note that New York broadly is comparable to other jurisdictions. According to Regulatory Research Associates, CECONY has a decoupling mechanism, as do more than half of the electric and natural gas proxy companies, although the specifics of each plan differ.[97] Because a decoupling mechanism is common, any impact on the ROE or the ability to earn the allowed ROE would be included in the proxy group data, so there is no impact on what the Company should be allowed. In addition, research has shown that statistically the presence of a decoupling mechanism has no impact on the cost of capital for electric or gas utilities.[98]

Q68: Are there any other business risk factors for CECONY?

A68: Yes. As discussed in the testimony of the Company's EIOP and Storm Response and Resilience Panel , CECONY has a large infrastructure program even for a New York utility given its service territory, which means the Company has large capital needs. Capital intense companies with large fixed cost (as opposed to variable costs) are more exposed to variations in revenue as fixed cost do not change with revenue. Therefore, the higher the capital intensity, the more vulnerable a company is to changes in revenue. The impact of these capital expenditures on CECONY is discussed in the testimony of Ms. Saegusa.

Q69: Can you please summarize your assessment of CECONY's business risk relative to the sample?

A69: Similar to other utility companies, the Company has seen substantial impacts from the on-going COVID-19 pandemic due to economic hardships within its service territory, changing consumption patterns, and changes in financial market conditions. Relative to the sample companies, CECONY has sometimes had a multi-year rate plan, which generally serves to reduce business risk, but may increase risks during times of high, unexpected inflation. However, CECONY's other regulatory mechanisms, such as reconciliations and revenue

[97] Regulatory Research Associates, "Adjustment Clauses: A state-by-state overview," November 12, 2019.

[98] *See*, for example, Joe Wharton and Michael J. Vilbert, "Decoupling and the Cost of Capital," The Electricity Journal vol. 28, 2015, pp. 19-28.

decoupling, are widespread and do not reduce risk as compared to other utilities. In addition, CECONY faces a notably challenging regulatory environment when compared to the proxy group companies. With recent climate and energy policies in New York State, the Company is facing significant changes to its operations, such as the reduction of fossil fuel usage – the exact implementation of which is uncertain.[99] In addition, regulatory intervention by the State has been high and noted by ratings agencies. Such factors add to the uncertainty CECONY faces.

B. Flotation Costs

Q70: Are there any other CECONY-specific flotation considerations relevant to the determination of its allowed ROE?

A70: Yes. It is my understanding that the Company (through its parent company Consolidated Edison, Inc.) has incurred flotation costs associated with equity issuances that have not been recovered in rates. These costs take the form of underwriting fees and discounts to the offer price. For example, if flotation costs represent approximately 2.5% of the proceeds raised by the issuances, only $97.50 out of every $100 raised in equity issuances would actually be available to finance CECONY's assets and operations. A straightforward method of recovery is to include such costs as an expense in the revenue requirement and allow recovery in rates. It is common among utilities to recover flotation costs either through a direct addition to the revenue requirements or through a ROE adder. To the extent these costs are not recovered as an expense item in the revenue requirement, they should appropriately be recovered via an adjustment to the return on equity going forward.

Q71: How should CECONY recover flotation costs?

[99] While the impact of carbon reduction on CECONY's risk profile could be substantial, I have not taken this aspect into account in my ROE recommendation as (1) I do not yet have sufficient information to quantify the effect and (2) I want to be relatively conservative. As such, I simply note that these are factors that need to be monitored closely as the impact could be substantial in future years.

A71: CECONY can either recover flotation costs as a straightforward addition to the revenue requirement or through an adjustment to the allowed ROE. I only consider the magnitude required if the amount is recovered as an adder to the ROE.

A standard approach to adjusting the allowed ROE to provide recovery of all past equity issuance costs can be implemented via a straightforward adjustment to the single-stage DCF model. In place of the standard single-stage DCF formula (equation 7), the following formula is used.

$$r = \frac{D_1}{P_0(1-f)} + g$$

where f is the percentage of proceeds lost to underwriting fees or other flotation costs. This formula recognizes that if shares trade at (for example) \$100, but 2.5% of the proceeds of the initial issuance of those shares was consumed by flotation costs, only $\$100 \times (1 - 0.025) = \$97.5$ represents value invested in cash-flow generating assets. Therefore, it is relative to this “adjusted” price, not the nominal market price, that investors’ required return should be measured.

Comparing the flotation cost-adjusted formula to the standard DCF formula for values of the dividend yield, growth rate, and financial leverage that are representative of the Electric Proxy Group (see Figure 20 below), I find that 10 basis points is an appropriate ROE adjustment to allow recovery of costs amounting to 2.5% of equity issuance proceeds.

Figure 20: Representative Flotation Cost Adjustment Calculation

		Without Flotation Cost Adjustment	With Flotation Cost Adjustment
Flotation Cost Share of Issuance Proceeds	[a]		2.5%
Sample Average Dividend Yield	[b]	3.4%	3.5%
Growth Rate Estimate	[c]	5.7%	5.7%
Single Stage DCF Cost of Equity	[d]	9.1%	9.2%
Sample Average Equity to Market Value Ratio	[e]	56%	56%
Sample Average Debt to Market Value Ratio	[f]	44%	44%
Sample Average Implied Marginal Cost of Debt	[g]	3.1%	3.1%
Tax Rate of CEONY	[h]	26%	26%
Single Stage DCF Overall Cost of Capital	[i]	6.09%	6.14%
Con Edison's Regulatory Equity Ratio %	[j]	50%	50%
Con Edison's Regulatory Debt Ratio %	[k]	50%	50%
Con Edison's Cost of Debt Estimate	[l]	3.05%	3.05%
Implied Cost of Equity	[m]	9.92%	10.02%

7. COST OF CAPITAL RECOMMENDATION

Q72: What do you recommend for CECONY's cost of equity in this proceeding?

A72: The CAPM/ ECAPM show a reasonable range of 10.25% to 11.25%, while the DCF model shows a reasonable range of 9.0% to 10.0% for the electric proxy group rounding to the nearest ¼ percent (and after I symmetrically truncated the estimated range). This is supported by a similar range for the Natural Gas proxy group and by a risk premium result of 9.8 percent for the electric group and 9.7 for the gas group. Consequently, I find a range a range of approximately 9.5% to 10.5% to be the reasonable range for electric utilities. In addition, for the reasons discussed above, I find CECONY to have at least as high risk as the average sample company. As noted previously, the fact that inflation has become an issue in recent months and is expected to remain high for a while, it is plausible that the cost of equity will increase during the time rates will be in effect (*i.e.*, 2023 onward). I recommend a ROE of in the upper half of the range of reasonableness for CECONY given its specific risks. As such, I recommend a range of 10 -10.5 percent on 50 percent equity. I also recommend that CECONY be allowed to recover flotation costs as an expense item in its revenue requirement.

Q73: Does this conclude your Direct Testimony?

A73: Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.
DIRECT TESTIMONY OF
DEPRECIATION PANEL

Table of Contents

I. INTRODUCTION AND PURPOSE OF TESTIMONY

Q. Would each member of the Depreciation Panel please state your name and business address?

A. My name is Qun Li. My business address is 4 Irving Place, New York, New York.

My name is Ned W. Allis. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. Ms. Li, by whom are you employed and in what capacity?

A. I am employed by Consolidated Edison Company of New York, Inc. ("Con Edison"). I hold the position of Accounting Supervisor in the Property Record department. I supervise the book depreciation accounting functions as well as being the rate case lead on depreciation studies for the Company.

Q. Ms. Li, please briefly outline your educational background and business experience.

A. I earned a Bachelor of Science degree from Wuhan Science and Technology University and later a Master of Accountancy from Bowling Green State University. I started my career working at Bao Steel Group as a civil engineer and holding positions of increasing responsibilities. I rose to the title of Assistant Project Manager. I am a Certified Cost Engineer. I also worked as a Senior Accountant/Accounting

Supervisor in the Peninsula Hospital Center and education fields. I have been employed by Con Edison since March 2012 as a Senior Accountant. I am a member of the Society of Depreciation Professionals ("SDP") and have completed several training courses conducted by the Society.

Q. Mr. Allis, by whom are you employed and in what capacity?

A. I am employed by Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"), where I am Vice President. I am responsible for conducting depreciation, valuation and original cost studies, determining service life and net salvage estimates, conducting field reviews, presenting recommended depreciation rates to clients, and supporting such rates before state and federal regulatory agencies. I am also responsible for Gannett Fleming's proprietary depreciation software, training of depreciation staff, and the development of solutions for technical issues related to depreciation.

Q. Mr. Allis, please briefly outline your educational background and business experience.

A. I have a Bachelor of Science degree in Mathematics from Lafayette College in Easton, PA. I am a member of the SDP and am a past president of SDP. I am certified as a depreciation expert by the SDP, which has established national standards for certification via an examination that I passed in September 2011. I was re-certified as a depreciation professional in March 2017 and January 2022.

I became employed by Gannett Fleming in October 2006 as an Analyst. My duties included assembling basic data required for depreciation studies, conducting statistical analyses of service life and net salvage data, calculating annual and accrued depreciation, and assisting in preparing reports and testimony setting forth and defending the results of the studies. In March 2013, I was promoted to the position of Supervisor, Depreciation Studies. In March 2017, I was promoted to the position of Project Manager, Depreciation and Technical Development. In January 2019, I was promoted to my current position of Vice President.

Q. Have the members of the Depreciation Panel previously testified before any utility commission on the subject of utility plant depreciation?

A. **(Li)** Yes. I have previously testified before the New York Public Service Commission (“NYPSC” or

"Commission") in Cases 13-E-0030, 13-G-0031 and 13-S-0032 for Con Edison and in Cases 21-G-0073 and 21-E-0074 for Con Edison's affiliate, Orange and Rockland Utilities, Inc. ("O&R").

(Allis) Yes. I have testified on the subject of depreciation before the NYPSC in several Con Edison and O&R cases, including Con Edison's most recent Cases 19-E-0065 and 19-G-0066. Additionally, I have testified on the subject of depreciation before the Florida Public Service Commission, the Nevada Public Utilities Commission, the District of Columbia Public Service Commission, the New Jersey Board of Public Utilities, the California Public Utilities Commission, the Connecticut Public Utilities Regulatory Authority, the Rhode Island Public Utilities Commission, the Massachusetts Department of Public Utilities, the Kansas Corporation Commission, the Maryland Public Service Commission, the New Hampshire Public Utilities Commission, and the Federal Energy Regulatory Commission ("FERC").

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

A. The Depreciation Panel's testimony:

- Presents the depreciation study performed by Gannett Fleming for the Company’s electric, gas and common plant;
- Presents annual depreciation accruals as of December 31, 2020 based on the Company’s existing rates and the proposed depreciation rates;
- Identifies the Accumulated Provision for Depreciation recorded on the Company’s books (“book reserve”) as of December 31, 2020, the computed reserve (also referred to as the theoretical reserve or calculated accrued depreciation) based on existing depreciation factors, and the computed reserve based on the proposed depreciation factors for electric, gas and common plant;
- Presents the variations between the book and computed reserves based on existing rates and the proposed depreciation factors for electric, gas and common plant and the Company’s proposal to recover the reserve deficiencies that exceed 10% of the theoretical reserve for electric and gas plant over 20 years; and
- Discusses the impact of New York’s law requiring decarbonization of the energy sector, how this

may impact depreciation for the electric and natural gas industries, and how the recommended service lives and reserve variation recovery for gas assets represent an initial step to recognize the potential impact of these goals.

Q. Is the Depreciation Panel sponsoring any exhibits in these proceedings?

A. Yes. The depreciation study, which was prepared by Gannett Fleming and reviewed by Ms. Li, is presented in the following exhibits prepared under our supervision and direction:

- Exhibit ___ (DP-1) entitled: "Consolidated Edison Company of New York, Inc., Depreciation Study, Electric, Gas and Common Plant as of December 31, 2020" ("Depreciation Study");
- Exhibit ___ (DP-2) entitled: "Consolidated Edison Company of New York, Inc., Electric, Gas and Common Plant, Summary of Annual Depreciation Rates as of December 31, 2020;"
- Exhibit ___ (DP-3) entitled: "Consolidated Edison Company of New York, Inc., Summary of the Computed Reserves for Depreciation as of December 31, 2020."

- Exhibit ___ (DP-4) entitled: "Consolidated Edison Company of New York, Inc., Electric, Gas and Common Plant, Summary of Annual Depreciation Rates for the Rate Years as of December 31, 2020;" and
- Exhibit ___ (DP-5) entitled: "Consolidated Edison Company of New York, Inc., Summary of the Computed Reserves for Depreciation for the Rate Years as of December 31, 2020."

Q. Please summarize any changes to depreciation expense levels due to Gannett Fleming's depreciation recommendations.

A. As set forth in its direct testimony, the Company's Accounting Panel has computed, based on depreciation rates we have supplied, that depreciation expense will increase in the Rate Year by $71.4 million for electric plant (i.e., from $1,363.4 million to $1,434.8 million) and by $107.8 million for gas plant (i.e., from $361.7 million to $469.5 million).

Q. Do the Company's proposed depreciation rates account for the Climate Leadership and Community Protection Act ("CLCPA")?

A. Yes. Counsel has advised us that the Commission has determined that the CLCPA applies to utility rate cases.[1] It is, therefore, appropriate to consider the potential impacts of New York’s carbon emissions goals in establishing the Company’s depreciation rates and recovery of reserve deficiencies. In doing so, we recommend a decrease in the service lives for the longer-lived gas accounts by as much as ten years (when compared to the results of service life analysis that does not consider the CLCPA impact). However, as discussed further in the Company’s Accounting Panel testimony, in order to mitigate the rate impact, the Company proposes to use depreciation rates based on a more gradual change to service lives for these accounts. As a result, the depreciation rates and reserve variations used in the Rate Years are those set forth in Exhibit ___ (DP-4) and Exhibit ___ (DP-5).

II. DEPRECIATION STUDY

Q. Please define the concept of depreciation.

[1] Case 19-G-0309 *et al.*, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service*, Order Approving Joint Proposal, As Modified, And Imposing Additional Requirements (August 12, 2021), pp. 69-70 (“National Grid Rate Proceeding”).

A. The Electric FERC Uniform System of Accounts defines depreciation as follows:

> Depreciation, as applied to depreciable electric plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of electric plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[1]

The Gas FERC Uniform System of accounts is similar:

> Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.[2]

We note that both the Electric and Gas Uniform Systems of Accounts specifically enumerate obsolescence,

[1] 18 C.F.R. 101 (FERC Electric Uniform System of Accounts), Definition 12.

[2] 18 C.F.R. 201 (Gas FERC Uniform System of Accounts), Definition 12.

changes in demand, and requirements of public authorities as factors that should be considered. These factors are addressed in this testimony and will continue to be assessed by the Company in future depreciation studies.

Q. In preparing the Depreciation Study, did you follow generally accepted practices in the field of depreciation?

A. Yes.

Q. Are the methods and procedures used in the Depreciation Study consistent with the Company's past practices?

A. Yes. We used the same methods and procedures in the Depreciation Study as those used in past depreciation studies conducted by the Company, as well as depreciation studies presented by other companies in rate proceedings before the Commission. The approach is to determine depreciation rates based on the straight-line method, the broad group average service life procedure and the whole life technique. Consistent with the prior depreciation study and the Company's current depreciation rates, we have used Iowa type survivor curves to estimate service lives.

Q. Please describe the presentation of the Depreciation Study in your exhibits.

A. The Depreciation Study, set forth in Exhibit ___ (DP-1), is presented in nine parts. Part I, Introduction, presents the scope and basis for the depreciation study. Parts II through V include descriptions of the methods and procedures used for the estimation of survivor curves and net salvage and the calculation of annual depreciation and the theoretical reserve. Part VI, Results of Study, presents a description of the results and a summary of the depreciation calculations. Parts VII through IX present graphs and tables that relate to the service life analyses, the net salvage analyses and the detailed depreciation calculations.

The tables on pages VI-4 through VI-7 of Exhibit ___ (DP-1), present the estimated survivor curve, the net salvage percent, the original cost of plant and the book depreciation reserve as of December 31, 2020, and the calculated annual depreciation accrual and applicable depreciation rate for each plant account or subaccount. The section beginning on page VII-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-1 presents the results of the net salvage analysis. The section beginning on page IX-1 presents the section beginning on page IX-1 presents the depreciation calculations related to surviving original cost as of December 31, 2020.

Q. Please explain how you performed the Depreciation Study.

A. The Depreciation Study began with a planning meeting held on July 1, 2021. We conducted the Depreciation Study over the next several months and concluded with the report that is included as Exhibit ___ (DP-1). The Depreciation Study included as Exhibit __(DP-1) used the straight-line whole life method of depreciation, with the broad group average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the service value (original cost of plant assets plus estimated costs of removal less estimated net salvage at the time of retirement) over the estimated service life of each group of assets in a systematic and rational manner.

Q. Were there other factors from the Company's previous rate case that influenced the Depreciation Study?

A. Yes. As part of the settlement in the Company's 2019 rate cases (Cases 19-E-0065 and 19-G-0066), the Company agreed to prepare a study on the potential depreciation impacts of climate change policies. That study, which we will refer to as the "Concentric Report" in our testimony, was prepared by Concentric Energy Advisors and filed with the Commission on June 1, 2021. The Concentric Report made recommendations for the Depreciation Study.

Q. What recommendations did the Concentric Report make for the Depreciation Study?

A. The Concentric Report found that the Company's prior depreciation study (p. 11) resulted in appropriate depreciation rates "as of the date of the [prior] depreciation study," the prior study's estimates were "reasonable" and "in line with industry wide best practices," and that the prior study adhered to the steps typically performed for a depreciation study. At the same time, it recommended the following potential modifications to the next study's presentation (p. 12):

a) Include a description of the utility in the depreciation study.

b) Include a description of significant property accounts including the type of assets included in the account, information learned during site tours and management meetings, a summary of the retirement rate analysis, and any other factors that resulted in the selection of depreciation parameters.

c) Consideration should be given to filing the data used in the completion of the retirement rate analysis, net salvage analysis, and depreciation calculations at the time of the initial depreciation study filing. In various jurisdictions these notes are filed as a package of additional workpapers and the Concentric Report recommends a similar practice.

d) The Concentric Report recommends that the depreciation study report continue the practice established in the 2019 Depreciation Study of preparing the retirement rate analysis using Iowa curves rather than H curves.

e) The Concentric Report notes that the accumulated depreciation reserve variance is not fully recovered through the use of a true-up mechanism in New York. The Concentric Report recommends the consideration of a move to a remaining life approach in order to recover fully the service value.

Q. Have these recommendations been incorporated into the Depreciation Study or testimony in this case?

A. Yes, except for recommendation (e). The Depreciation Study includes a description of the utility, descriptions of the factors that led to the selection of depreciation parameters for each significant property account, and the use of Iowa curves rather than h-curves. Additionally, the data and other supplemental information have been included as workpapers with the Company’s filing.

While we agree with the Concentric Report that a move to the remaining life technique would be appropriate and consistent with the predominant practices in the utility industry, the Commission has expressed a preference for the whole life technique. For this reason, we have used the whole life technique for the Depreciation Study. However, as we discuss later in our testimony, we believe it is important to address the reserve variations identified in the Depreciation Study, particularly for gas assets.

Q. How did you determine the recommended annual depreciation accrual rates?

A. This was done in two phases. In the first phase, we developed estimates of the service life and net salvage factors for each depreciable group (that is, each plant account or subaccount identified as having similar characteristics). In the second phase, we calculated the annual depreciation accrual rates using the applicable average service lives and net salvage factors.

Q. What part does the average service life play in the determination of depreciation rates?

A. The average service life is the period over which the original cost of plant will be depreciated. For example, with an average service life of 25 years, annual depreciation is 1/25, or 4%, of the original cost of the plant before taking into account the net salvage factor.

Q. What is the effect on annual depreciation expense of a change to an average service life?

A. The depreciation expense accrual varies inversely with its underlying average service life, and all else being equal, the longer the average service life, the lower the annual depreciation rate and the lower the annual depreciation expense. Conversely, the shorter the average service life, the higher the annual depreciation rate and the higher the annual depreciation expense.

Q. What part does net salvage play in the determination of depreciation rates?

A. Depreciation is intended to recover the full costs of Company assets over the period of time they are in service. The full cost of an asset includes both the original cost when the asset was installed and the net salvage at the end of the asset’s life. Thus, in addition to providing for recovery of the original cost of plant over its estimated average service life, annual depreciation rates include an estimated net salvage factor. The purpose of this estimated net salvage factor is to reflect, over the life of the plant, the expected gross salvage value of plant less the expected cost of removal upon retirement. With few exceptions, most plant assets result in negative net salvage upon retirement, which means that removal costs exceed gross salvage value. Gross salvage and removal cost values are netted, expressed as a percentage of the plant’s original cost, and included in the annual depreciation rate. As a result, and in accordance with basic depreciation principles and the NYPSC's Uniform System of Accounts, the service value of an asset is allocated evenly over the estimated useful life of the asset.

Q. Please describe the first phase of the Depreciation Study in which you estimated the average service life and net salvage factors for each plant account or subaccount.

A. The service life and net salvage study consisted of compiling historical data from records related to Con Edison's plant; analyzing the data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning practices and plans as they relate to plant operations; making visits to various sites to view the physical condition of facilities; and interpreting the data and information along with the average service lives and net salvage factors used by other electric and gas utilities to form judgments of average service lives and net salvage factors applicable to Con Edison's plant and equipment.

Q. You mentioned that preparing the Depreciation Study involved visits to Con Edison facilities. What is the significance of these visits?

A. We made a field review of Con Edison property as part of the Depreciation Study during September 2021. Mr. Allis also conducted field reviews in December 2018, October 2015 and November 2014 for the Company’s previous depreciation studies. Depreciation studies should not be limited only to statistical analysis or visual comparisons of smoothed survivor curves based on actual mortality experience and standardized survivor curves. Field reviews, as well as discussions with operating and engineering personnel, are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected causes of future retirements. We incorporated this knowledge, as well as information from other discussions with management, in the interpretation and extrapolation of the statistical analyses.

Q. What historical data did you analyze to estimate average service lives?

A. We analyzed the Company’s accounting entries that record plant asset transactions during the period 1938 through 2020. These transactions included additions, retirements, transfers and related balances.

Q. What method did you use to analyze the data?

A. We used the retirement rate method. This is the most appropriate method when retirement data, covering a long period of time, is available because it determines the average rates of retirement experienced by the Company during the period of time covered by the Depreciation Study. It is also the method Con Edison used in past depreciation studies and is the overwhelmingly predominant approach used in depreciation studies across the country when aged data are available.

Q. Please describe how you used the retirement rate method to analyze the Company's service life data.

A. We performed the retirement rate analysis for each different group of property, generally a particular plant account, in the Depreciation Study. For each property group, we used the retirement rate data to form life tables which, when plotted, show original survivor curves for that property group. Each original survivor curve represents the average survivor pattern experienced by the vintage groups during the experience and placement band studied. Because original survivor curves do not include the complete experience of most vintages of plant and because future survivor characteristics may be different from those experienced in the past, the experienced survivor patterns do not necessarily describe the property group's life characteristics. Therefore, interpretation of the original survivor curves is required for them to be valid considerations in estimating future service lives. Standard survivor curves, such as the Iowa-type survivor curves, are used to perform these interpretations.

Q. What is an "Iowa-type survivor curve" and how can it be used to estimate the average service life characteristics for each property group?

A. Iowa-type survivor curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. The Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired. Iowa curves were used in the previous depreciation study and are the basis for Company’s current depreciation rates. Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves can be used to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements.

The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. Take the Iowa 50-R1.5, for example. The first designation indicates an average service life of fifty years. The second designation indicates a right-moded, or R, type curve (the mode occurs after average life for right-moded curves). The third designation indicates a relatively low height of 1.5, for the mode (possible modes for R type curves range from 1 to 5).

Q. What approach did you use to estimate the lives of significant facilities such as electric production plants or gas storage facilities?

A. We used the life span method to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. We used the life span method for electric portion of the Company’s steam production plants and the gas LNG facility. In this method, the survivor characteristics of such facilities are described using interim survivor curves and estimated probable retirement dates.

The interim survivor curves describe the rate of retirement related to replacements elements of the facility, such as piping, pumps, boiler tubes, and turbine blades, during the facility’s life. The probable retirement date provides the final retirement rate for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of assets installed over multiple years for a particular facility, inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. Has the Company previously used the life span method?

A. Yes. The Company used the life span method for the same facilities in the Company's previous depreciation study. The life span method has been accepted by many public utility commissions across the United States and Canada, including the NYPSC.

Q. What are the bases for the probable retirement dates that you have estimated for each facility?

A. The probable retirement dates are based on estimated life spans that reflect our consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other utilities for similar facilities. For certain facilities, the life spans result in probable retirement years that are many years in the future. The retirements of these facilities are not yet subject to specific management plans, as such plans would be premature. At the appropriate time, detailed studies of the economics of rehabilitation and continued use or retirement of the facility may be performed, and the results incorporated in the estimation of the facility's life span. However, in order to allocate the costs of these facilities properly, a probable retirement date must be estimated based on the information available today.

Q. Are the recommended life spans the same as those the Company used in the depreciation study it submitted in its previous rate case?

A. Yes.

Q. Is the life span method consistent with the whole life technique?

A. Yes. The life span method is a method of determining the average service life and dispersion pattern for each vintage of plant within a depreciable group. This method can, therefore, be used with either the whole life or the remaining life technique. When using the life span method with the whole life technique, as is used in the Depreciation Study, the average service life is calculated for each vintage based on the estimated retirement date and interim survivor curve. The average service life is then used to calculate depreciation expense.

Q. Please provide an example of how the annual depreciation accrual rate for a particular plant account is presented in the Depreciation Study.

A. We will use electric plant Account 367, Underground Conductors and Devices, as an example because it is the largest depreciable account.

The Company used the retirement rate method to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1938 through 2020 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1938-2020 and 1981-2020 experience bands are presented on pages VII-84 through VII-91 of Exhibit ___ (DP-1). The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-84 shows $61,136,869 retired at age 0.5 years with $7,996,364,637 having been exposed to retirement. Consequently, the retirement ratio is 0.0076 ($61,136,869/$7,996,364,637) and the survivor ratio is 0.9924 (1 – 0.0076). These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 55-R0.5, on page VII-83.

The calculation of the annual depreciation accrual and the theoretical reserve related to the original cost of plant for Account 367 as of December 31, 2020 is presented on pages IX-59 through IX-62. The calculations are based on the 55-R0.5 survivor curve and 90% negative net salvage factor, and the attained age for each vintage. The tabulation sets forth the installation year, the original cost, average service life, calculated annual depreciation rate and accrual, average remaining life, and calculated accrued depreciation factor and amount (that is, the theoretical reserve ratio and theoretical reserve). The total annual accrual of $249,973,598 and theoretical reserve of $2,315,990,536 for the account are brought forward to the table on page VI-5. The reserve variation of negative $600,084,164 shown on page VI-5 is calculated by subtracting the $2,315,990,536 theoretical reserve from the book reserve for the amount of $1,715,906,372. A negative variation indicates that there is a book reserve deficiency for this account.

Q. Please describe how you determined the proposed net salvage factors.

A. Consistent with well-established industry practices, we determined the net salvage factors by considering relevant information such as the results of historical net salvage analyses, the existing net salvage rates in effect, the Company's current practices with regard to net salvage, and the net salvage factors used by other electric companies.

Q. Please describe the statistical net salvage analyses.

A. In the statistical net salvage analyses, net salvage is expressed as a percentage of the book cost of plant retired by calendar year. This method provides a statistical basis for the level of net salvage that can be expected to occur in the future.

Q. Are the net salvage analyses and approach you used to reflect net salvage in depreciation rates consistent with authoritative depreciation texts?

A. Yes. The *National Association of Regulatory Utility Commissioners Public Utility Depreciation Practices* ("NARUC Manual") and Wolf and Fitch's *Depreciation Systems* ("Wolf and Fitch") are well-regarded texts that are considered to be authoritative depreciation sources by depreciation professionals. These texts describe the method of estimating net salvage and explain that expected net salvage at the time of retirement of plant assets is expressed as a percentage of original cost of the plant that will be retired and is estimated using the same methods we have employed.

Q. Are the methods used in the Depreciation Study for the net salvage analysis widely accepted in the industry?

A. Yes. The net salvage analysis used in the Depreciation Study is the predominant approach in the utility industry. In the vast majority of jurisdictions, including New York, a portion of depreciation expense includes a provision for the prospective recovery of future net salvage over the service life of the underlying assets, and the net salvage factors are estimated using the same methods used in the Depreciation Study. This approach is consistent with the NYPSC Uniform System of Accounts, the ratemaking practices of most other state regulatory commissions, and the ratemaking approach of the FERC.

Q. What have you proposed for gas assets expected to be retired as a result of the Company's leak-prone pipe replacement program?

A. For the Depreciation Study, the Company's mains and services accounts were segregated into the portion that will be retired through the Company's pipe replacement program and all other mains and services. Con Edison plans to complete this program by the end of 2040. Accordingly, our proposal for the assets that are planned to be replaced, which consist primarily of older cast iron and bare steel pipe, is to recover the remaining costs by 2040. This is similar to the approach used in O&R’s most recent rate case (Case 21-G-0073).

Q. In addition to the pipe replacement program, are there any other notable changes in this case to the service life estimates for gas assets?

A. Yes. We propose to shorten the service lives for the longer-lived gas accounts (*i.e.,* structures and improvements, mains, services, meters, meter installations, house regulators and house regulator installations) from what the Company has historically experienced due to potential CLCPA impacts . For most of these accounts, our recommendation is to shorten the average service lives by ten years when compared to the lives that would result from a depreciation study that does not incorporate CLCPA impact. For the same reason, we also recommend the full recovery of the reserve variation for gas plant. These impacts will be discussed in more detail in the next section. However, in order to mitigate the overall rate increase, the Company’s proposal in this case is based on a more modest change in service lives and proposal to address the gas reserve deficiency.

III. CLIMATE LEADERSHIP AND COMMUNITY PROTECTION ACT

Q. Does the Company's rate filing reflect potential impacts of the CLCPA?

A. Yes. Con Edison supports the State's law to reduce greenhouse gas emissions to net zero by 2050. Because the State is still developing CLCPA recommendations and regulations, the pathway to achieve the necessary carbon emissions reductions is uncertain -- and may continue to be uncertain even after the State adopts regulations. The precise role of heating electrification is still to be determined, but it is clear that it will be a component as evidenced by: (1) the heating electrification programs that Con Edison is already implementing; (2) New York City's new law that prohibits the use of gas in new buildings;[1] and (3) Governor Hochul's stated intent to prohibit the use of natural gas in new construction by 2027.[2] Nevertheless, it would also be incorrect to state now that the State will move to full electrification by

[1] The New York City Council - File #: Int 2317-2021, *available at* https://legistar.council.nyc.gov/LegislationDetail.aspx?ID=4966519&GUID=714F1B3D-876F-4C4F-A1BCA2849D60D55A&Options=ID%7CText%7C&Search=combustion.

[2] Governor Hochul Announces Plan to Achieve 2 Million Climate-Friendly Homes By 2030 – NYSERDA, *available at* https://www.governor.ny.gov/news/governor-hochul-announces-plan-achieve-2-million-climate-friendly-homes-2030.

2050. The State could rely on a combination of renewable generation for heating electrification and efforts to decarbonize the fuels delivered using the Company’s existing gas infrastructure, which could then require additional investment. The differences in pathways are significant in terms of the impact on the gas system (and on the electric system) and it is premature to forecast which will occur. The eventual pathway will depend on specific CLCPA regulations, as well as new and next generation technologies. Other potential impacts of the CLCPA are discussed in more detail in the testimony of the CLCPA Panel.

Q. Does the uncertainty regarding the specific pathway to achieve the CLCPA’s goals mean that the potential impacts should not be considered for the Company’s depreciation analysis?

A. No. Uncertainty does not mean that nothing will change or that the future will be the same as the past. While we do not believe the current CLCPA implementation status dictates an overly aggressive approach to depreciation, we do believe that there is enough information to reasonably expect that many of the Company’s assets will have shorter lives than has historically occurred. We note, as discussed previously, the Commission's Uniform System of Accounts specifically states that factors such as obsolescence and the requirements of public authorities should be considered when determining the appropriate depreciation expense. Based on the information available today, it is highly likely and reasonable to expect that the CLCPA's goals for greenhouse gas emissions reductions will reduce natural gas usage. As a result, we considered these impacts when estimating gas service lives and net salvage factors in this case.

Q. How has the Company considered the CLCPA impact for gas assets?

A. Because the Company and the State can reasonably expect at least a material reduction in total delivered gas volume due to the CLCPA, the Company believes it should begin the necessary process of aligning gas depreciation rates with the future. Accordingly, we recommend a reduction to certain gas average service lives in this case. This is appropriate because changes in energy consumption would impact the Company's service lives. For example, if a customer leaves the system, there would be retirements of the meter, service line and any other customer-specific infrastructure at the customer locations. If enough customers left the system, this could impact other assets such as gas mains and measuring and regulating station equipment. The Company has also implemented a non-pipeline alternatives program as part of its overall plan for helping the State achieve CLCPA goals. In certain cases, this will result in the replacement of natural gas assets with heat pumps or geothermal alternatives.

In addition, the service lives of many gas assets are already quite long and in some instances are longer than many other gas utilities. For example, the average service life for the Company's current depreciation rates for gas mains (excluding cast iron mains) is 85 years (in the previous depreciation study we had recommended an 80-year average service life). This is an average – the current survivor curve estimate for gas mains assumes that many will last much longer than 85 years. As a result, even if the Company's lives were shortened by 10 or 15 years they would still represent fairly long lives – and in many cases still be as long as or longer than many used in the industry for gas mains.

Q. Have you prepared any analyses of the results of different scenarios showing the impact of different service life assumptions on depreciation?

A. Yes. Table 1 below is a summary of different scenarios considered and compares each to the depreciation expense that results from the Company's current depreciation rates. The first scenario, labeled "Historical Experience," shows the results of a study if depreciation is determined in a more traditional sense, with service life estimates more consistent with the Company's historical service life experience and using the straight-line method. The other scenarios in the table, which show the results of different approaches of incorporating CLCPA impacts, include three scenarios with shorter service lives, labeled "5-Year Shorter Lives" and "10-Year Shorter Lives," and "15-Year Shorter Lives." As the names imply, these scenarios incorporate varying degrees of shorter service lives for certain accounts.[1] Finally, we show the result of a scenario in which all costs are recovered by 2050.

[1] We note that in each scenario the shorter lives are not necessarily strictly all identical, e.g., 10-years shorter. However, for the larger accounts, such as mains and services, the degree to which lives have been shortened corresponds to the scenario name.

Table 1: Comparison of Depreciation Scenarios for Gas Plant

Function	Current Depreciation	Historical Experience	5-Year Shorter Service Lives	10-Year Shorter Service Lives	15-Year Shorter Service Lives	Recover by 2050
Other Storage	$5.8	$6.9	$6.9	$6.9	$6.9	$6.9
Transmission	21.2	22.5	23.9	26.0	27.3	39.5
Distribution	202.3	222.0	238.7	256.7	277.5	424.8
Reserve Variation Amortization	8.0	26.0	34.7	47.2	56.8	102.1
Total	**$237.3**	**$277.5**	**$304.2**	**$336.8**	**$368.5**	**$573.3**

Q. Does Table 1 also reflect the impact of each scenario on the amortization of reserve deficiencies?

A. Yes. All else equal, shorter service lives result in a higher theoretical reserve which, in turn, results in larger reserve deficiencies. The Reserve Variation Amortization row in Table 1 shows the result of amortizing the full reserve variation over a 20-year period for each scenario. Reserve Variation is discussed in more detail in the next section.

Q. What do you recommend?

A. In consideration of the results of the scenarios shown above, as well as the factors that will potentially impact the service lives of the Company’s assets, we recommend the 10-Year Shorter Lives scenario shown in Table 1, which includes a 20-year amortization of the full reserve variation for gas plant resulting from these service lives. We believe that the 10-Year Shorter Lives appropriately balances the reasonable expectation of potential CLCPA impacts and the uncertainty that exists at this stage of CLCPA implementation.

Q. Does the Company propose to adopt the 10-Year Shorter Lives scenario in this rate case?

A. No. As discussed in more detail by the Accounting Panel, the Company's revenue requirement incorporates the depreciation rates from the "5-Year Shorter Service Lives" scenario with the recovery of the reserve deficiency that exceeds 10% of the theoretical reserve based on the "5-Year Shorter Service Lives Scenario." The Company is making this proposal to mitigate the overall rate increase in this case.

Q. Why is adopting the "5-Year Shorter Service Lives" scenario reasonable?

A. Although not the optimal approach, the "5-Year Shorter Service Lives" scenario is reasonable because it moves forward while accounting for necessary factors, including CLCPA requirements, customer bill impacts, and the early stage of CLCPA implementation. Moving at a more gradual pace in consideration of customer bill impact is within the realm of reasonable outcomes. Not moving at all is not. Given the potential for significant changes in the gas industry, we consider the Company's proposal to be the minimum CLCPA impact that the Commission should recognize in this proceeding.

Moreover, the Company is well ahead of other utilities in examining this issue. The Concentric Report filed in Cases 19-E-0065 and 19-G-0066 included preliminary evaluation of the impact of climate change legislation on depreciation. The Company was the first of the investor-owned utilities to commit to and perform such a study. For other utilities, these studies are, as the Commission recently indicated, "an appropriate way to address concerns … over the need to consider proper depreciation rates that should apply to reflect the CLCPA's impacts on natural gas delivery infrastructure."[1] Having completed the study, the Company is in a different position. In order for it to move forward with a CLCPA-compliant future, the Company should be permitted to take the next step and

[1] See Cases 20-E-00380, *et al.*, *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric and Gas Service*, Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements, at p. 87.

implement at least a modest reduction in gas depreciable lives.

Q. Are any of the scenarios shown in Table 1 accelerated depreciation?

A. No. The shortening of service life estimates that we are proposing in the depreciation study, and as shown above in Table 1, is not accelerated depreciation. Accelerated depreciation describes methods of depreciation in which depreciation is higher in the earlier years and lower in the later years of an asset's life (when compared to the straight-line method). None of the scenarios shown in Table 1 use accelerated depreciation. Each uses the straight-line method, and the only differences are assumptions about the service lives of the Company's assets.

Q. Are you familiar with the Commission's decision related to the impact of the CLCPA on depreciation in a recent case involving Corning Gas Company?

A. Yes. In Case 20-G-0101, Corning Gas Company proposed to depreciate gas assets consistent with the Recover by 2050 scenario shown above. We note this is also similar to an Economic Planning Horizon of 2051 scenario considered in the Concentric Report. The

Commission did not adopt Corning's proposal, stating in its order (pp. 30-31):

> We find that the Company has not demonstrated that its proposed useful lives are anything more than speculation. The dire circumstances raised by the Company are far from the only potential outcomes from the CLCPA. If in the future we were to take the drastic step of directing a regulated gas utility to cease operations, the mechanism to do so would not be what the Company proposes in this case – a large transfer of cash from ratepayers to shareholders. We note also that the Company proposes no plan for its customers to transition away from gas by 2050 and proposes no limitations on its use of the proposed incremental ratepayer funding. The implementation of the CLCPA by the Commission will be difficult, complicated and potentially expensive, but however it is implemented the plan will not look like what the Company has proposed here.

Q. Is your proposal foreclosed by the Corning decision?

A. No. First, what Con Edison has proposed is very different from Corning's proposal. We are not proposing to recover all costs by 2050; the Company's proposal incorporates the far more limited step of reducing gas service lives by five years. As Table 1 shows, the Recover by 2050 Scenario is almost $230 million higher than our recommended 10-Year Shorter Service Lives scenario. It is almost $280 million greater than the 5-Year Shorter Service Lives scenario the Company has proposed.[1] While our recommendation would result in an increase in depreciation of approximately 41% when compared to current depreciation rates and reserve variation amortizations (and the Company's proposal an increase of approximately 23%), the Recover by 2050 Scenario would result in an increase of more than 140% - more than doubling current depreciation expense.

Second, while the Recover by 2050 scenario represents one end of the range of possible CLCPA outcomes (that is, it is an upper extreme with regard to depreciation expense), we note that a "business-as-usual" approach represents the lower end of the range of possible outcomes. That is, similar to the Recover by 2050 scenario, the depreciation expense resulting from the Historical Experience scenario is at the outer end of the range of possible outcomes. Indeed, just as the Commission considered the Recover by 2050 Scenario to be speculative, we believe the same should be said of the Historical Experience scenario, because in our view there is no scenario where CLCPA requirements are met and there is no corresponding material reduction

[1] This is with recovery of the reserve variation above 10% of the theoretical reserve.

in gas usage. In this context, our recommendation of a 10-year decrease to long-lived lives is reasonable (and the Company's proposal of a 5-year reduction is conservative).

Q. What are the risks of using a "business as usual" approach such as the Historical Experience scenario?

A. Such an approach involves several risks. The first risk is the potential for future customers to have to bear the impact of cost recovery associated with infrastructure that is not used to meet their energy needs, causing intergenerational inequity. If depreciation rates are too low today, future customers will have to pay an excessive share of the cost of the Company's assets as a transition to other energy sources takes place. Further, there is the risk that customers will leave the system as they electrify their energy usage, which would push additional costs to the future customers that remain. These risks are related – if depreciation is higher in the future and customers have left the system, there will be fewer customers to pay the remaining costs of the Company's assets, further compounding intergenerational inequity resulting from depreciation rates being too low today. Finally, there are additional equity concerns because the customers who remain may be disproportionately low- and moderate-income customers who are not able to electrify their energy usage as easily as customers with more resources. That is, if the recognition of the CLCPA's impact on depreciation is deferred to future cases, there is a risk that the customers who bear a disproportionate share of the costs of the CLCPA will be those least able to afford these costs.

Q. Are there similar risks if depreciation rates are set too high today?

A. No. The risks are not symmetrical. If depreciation rates are set too high today – and if in the future assets live longer and customers have not left the system – then depreciation rates will be adjusted through the amortization of reserve variations.[1] Customers will pay lower costs for depreciation in the future. Additionally, rate base will be lower than it otherwise would have been, further reducing costs for customers (as well as Company earnings). In contrast if depreciation rates are too low today – and if customers electrify and leave the gas system – then

[1] Because the Company has reserve variations for both electric and gas service, in actuality this likely means that there would be smaller reserve variations to address in the future.

the impact on future customers will be much greater because there will likely be fewer customers to pay the remaining capital costs. They will also have to pay a higher return on rate base, further compounding the issue. Lastly, they will likely have to bear the costs of assets that are retired without being fully recovered, which is also inequitable.

For these reasons, the risks resulting from the CLCPA's goals are most appropriately dealt with by incorporating the potential for shorter asset lives into depreciation rates today. The sooner the Commission incorporates these factors, the lower the risk to future customers, the lower the potential for rate shock in the future, and the lower total cost to customers over time. Deferring these decisions will both increase the risk of dramatic impacts on future rates and will cost customers, particularly low- and moderate-income customers, more in the long run.

Q. Will the Company continue to assess the impact of the CLCPA in future depreciation studies?

A. Yes. As the pathways to achieving CLCPA requirements further develop, the Company will assess their impact on the depreciable lives of its gas assets. This stepped approach recognizes the CLCPA and the reality that the pathways to reach it are likely to affect the gas business, while maintaining flexibility. This approach will allow the Company to adapt to future trends, regulations and technological advances. Finally, the Company notes that if it turns out that gas heating will be eliminated at some point in the future as part of CLCPA goal achievement,[1] then this is an important first step that the Company can continue and/or increase in future gas rate cases.

Q. How has the impact of the CLCPA been considered for electric assets?

A. As also discussed in the testimony of the CLCPA Panel, the CLCPA will impact electric assets in a variety of ways. The change in electric generation from fossil power plants to renewables will cause changes in the transmission system, as substations and transmission lines will have to be added, upgraded or replaced to incorporate energy from different sources in different locations. There will potentially be similar changes to the distribution system due to both the additions of Distributed Energy Resources ("DERs") and changes in the load due to electrification.

[1] The New York City Council voted on December 15, 2021 to ban the use of natural gas in certain new buildings in 2023.

New technologies will be needed for the grid to incorporate the changing energy mix. Reliability and resiliency will be of increasing importance as the electric grid serves additional energy needs (*e.g.*, winter heating). Investments to upgrade the grid will also have to incorporate the impact of a warming climate and the potential for more frequent and severe weather events.

At this time, we do not expect the total impacts of these factors to result in changes to the average service lives of electric assets. However, the CLCPA is likely to result in significant investments in the electric system, and these investments may result in the replacement of a variety of assets. As a result, while we do not recommend changes in the service lives for electric assets as the result of the CLCPA, we do believe that any increases in service lives should be limited, particularly because Con Edison’s service lives are already fairly long when compared to those of others in the industry.

IV. HISTORICAL TREATMENT OF RESERVE DEFICIENCIES

Q. Please provide background information on depreciation reserve variations.

A. In order to test the adequacy of the book reserve for depreciation, we have compared the book reserve at year-end to a theoretical reserve calculated using average service lives, survivor curves and net salvage factors based on the Depreciation Study. The results are summarized in Exhibit ___ (DP-3) and Exhibit ___ (DP-5) and discussed later in this direct testimony. The variation between the book and theoretical reserves can be expressed both in total dollars and as a percentage of the theoretical reserve. Results of such a study can indicate either a positive variation (sometimes referred to as a “book reserve excess”) or a negative variation (sometimes referred to as a “book reserve deficiency”). For example, a book reserve of $190 and a theoretical reserve of $200 would result in a book reserve deficiency of $10, or 5%.

Q. What factors could lead to a book reserve deficiency?

A. The deficiency may be the result of historic depreciation rates set at a level lower than required to provide for the level of annual depreciation expense necessary to match actual experience. Reasons for “inadequate” depreciation rates can be average service lives that are too long to recover the plant at a fast enough rate, and thus do not allow for the timely recovery of the investment, or a negative net salvage component of the depreciation rate that does not provide an adequate level of recovery for removal costs. In addition to service lives and salvage factors, the actual dispersion of retirements (*i.e.*, when retirements occur in relation to average service lives) may have changed or varied from the historical pattern that led to the selection of the survivor curves being used.

Q. Is it common to have a reserve variation?

A. Yes. Service life and net salvage estimates can change over time, and these estimates are updated when a new study is performed. It is expected that there will be some variation between the book and theoretical reserves. However, because New York has historically used whole life rates, rather than remaining life depreciation rates (which automatically correct for any reserve variations), corrective action is often required. At a minimum, corrective action should be taken when the variation is large. In New York, corrective action has typically been taken when the variation exceeds 10% of the theoretical reserve.

Q. Is there a book reserve deficiency related to the Company's electric, gas and common plant?

A. Yes. There is a reserve deficiency for electric, gas and common plant.

Q. Has the Commission previously taken action to address the large and persistent reserve deficiency for the Company's electric plant?

A. Yes, but only for a portion of the deficiency. In Case 07-E-0523, due to concern about the potential size of the rate increase, the Commission, in its Order Establishing Rates for Electric Service (issued March 25, 2008), stated (p. 75) it would "limit the recovery of the depreciation reserve deficiency to a 15-year amortization of $162.5 million which is the amount in excess of the minus 10% level of the tolerance band that we have traditionally employed to measure the significance of reserve deficiencies." The Commission employed a similar approach in Case 09-E-0428 when an incremental amount of deficiency was again set for amortization and recovery as a result of the settlement of issues in that case.

More recently, Cases 16-E-0060 and 16-G-0061 resulted in a settlement. That settlement agreement resulted in an annual amortization of approximately

$11.6 million for electric service (plus an annual amortization of approximately $3.8 million for the unrecovered costs of the Hudson Avenue Station). No amortization for gas service resulted from that settlement.

The settlement agreement from the Company's most recent rate cases (Cases 19-E-0065 and 19-G-0066) moved towards a more reasonable approach to addressing the electric reserve deficiency and a moderate amortization of the gas reserve deficiency. For electric service, the settlement (p. 54) resulted in a $71.3 million annual recovery (in addition to the $11.6 million recovery for electric service and $3.8 million for Hudson Avenue from Case No. 16-E-0060). For gas service, the settlement resulted in an $8.0 million annual recovery related to the reserve deficiency.

Q. How have the reserve deficiencies changed from the previous depreciation study?

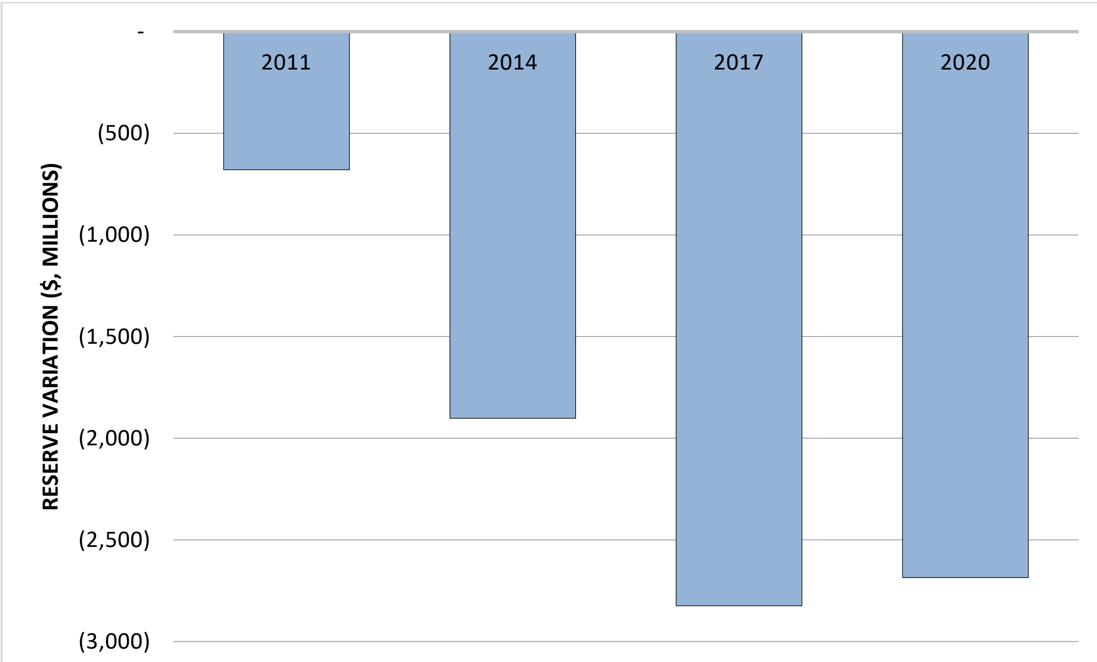
A. The electric reserve deficiency has moderated somewhat due in part to the result of the settlement agreement in Case No. 19-E-0065. Nevertheless, it remains very large and is relatively similar to the reserve variation in the previous depreciation study. The gas reserve deficiency has continued to grow. We note that if the CLCPA's impacts are greater than anticipated in our recommended depreciation rates, particularly for gas, then the reserve deficiencies would grow even larger.

Q. How have the reserve deficiencies grown over time?

A. Over the past decade, the reserve deficiencies for both electric and gas have grown significantly. This has occurred both because of reserve activity over this time, but also because the depreciation rates and corrective action adopted has not been sufficient to materially address the reserve deficiencies.

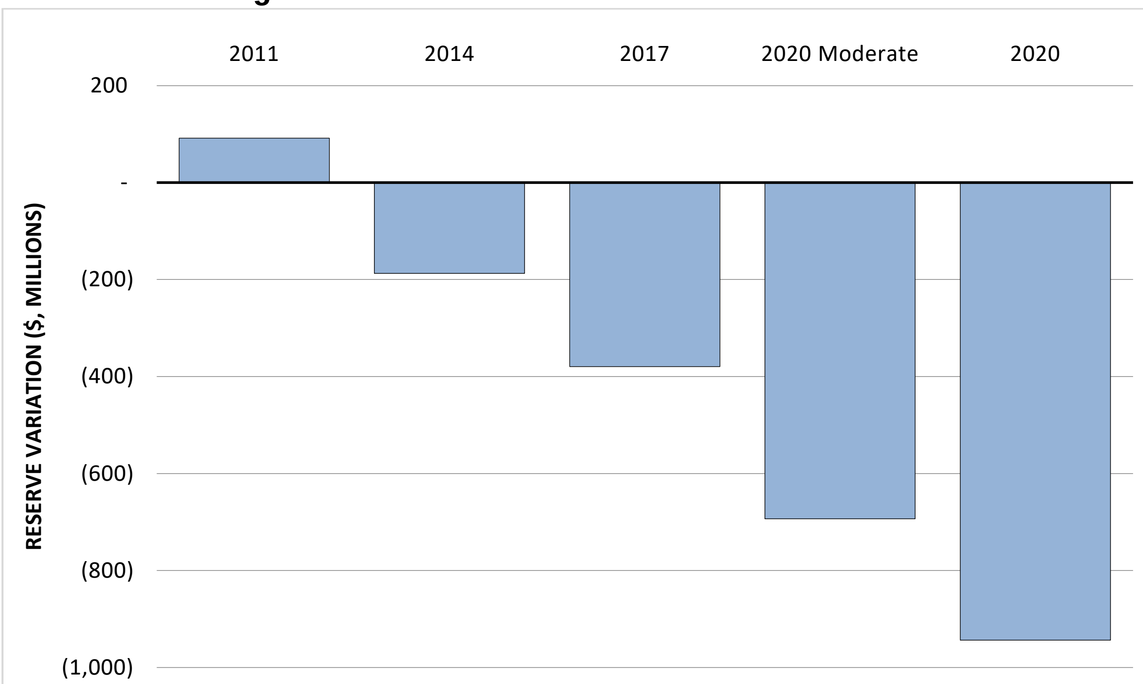
Figures 1 and 2 below show the reserve deficiencies resulting from the four most recent depreciation studies (including the current study) and illustrate that the reserve deficiencies have grown significantly (*i.e.*, the reserve variations have become more negative) from 2011 to 2020. For electric service, the reserve deficiency grew from approximately $680 million in 2011 to $2.8 billion in 2017, although it has moderated slightly to $2.7 billion in 2020. However, this is still a very large reserve deficiency and continued remedial action will be necessary so that the Company has an opportunity for the return of its capital investments.

Figure 1: Electric Plant Reserve Variations



For gas service, the reserve variation has changed from a $92 million reserve “excess” to a $944 million reserve deficiency over the same period. The trend to a growing reserve deficiency has been apparent in each of the two previous depreciation studies. However, the potential CLCPA impacts have caused the reserve deficiency to grow even larger. Figure 2 below shows the reserve deficiency in 2020 that would result from our recommended depreciation rates, as well as the more moderate proposal incorporated into the Company's revenue requirement in this case.

Figure 2: Gas Plant Reserve Variations



Q. Given the growth in the reserve deficiencies for both electric and gas service, is it important that the Commission address reserve deficiencies in this case?

A. Yes. The growth in the reserve deficiency illustrates that action is needed to address the reserve deficiencies. Additionally, while there has been some improvement in the electric reserve deficiency, additional action is needed both because the reserve deficiency remains very large and because it has only declined slightly since the last depreciation study. It is important to keep in mind that deferring the recovery of reserve deficiencies does not reduce rates in the long run. Rather, by pushing costs out into the future, depreciation deferrals increase costs to customers over time. This traditionally occurs for two reasons and the CLCPA adds a third. First, additional costs need to be recovered through depreciation or amortization of reserve deficiencies in the future. Second, because accumulated depreciation is a reduction to rate base, customers pay a return on any reserve deficiencies, which is an increase to cost in both the short- and long-run. Third, as discussed in the previous section, the impacts of the CLCPA could result in customers leaving the gas system, leaving those who remain to bear the full costs of the reserve deficiency. In light of all of these considerations, we recommend remedial action to address the reserve deficiencies for both electric and gas service, which is discussed further in the next section.

Q. You noted previously that the Concentric Report recommends the remaining life technique as opposed to the whole life technique. Would the remaining life technique address reserve variations?

A. Yes. The remaining life technique calculates depreciation rates such that the remaining service value (original cost less net salvage less book accumulated depreciation) is allocated over the remaining life of the Company's assets. As a result, it automatically includes corrective action related to reserve variations. The remaining life technique is used in the vast majority of U.S. regulatory jurisdictions and had the remaining life technique been used previously in New York, it is likely that Con Edison's reserve variations would not have grown as large. However, we recognize that in the past the Commission has preferred the whole life technique and for this reason our recommendation in this case is an amortization of the Company's reserve variations rather than the remaining life technique.

V. TEST OF THE BOOK RESERVES

Q. What are the amounts of the variations between the book reserves and theoretical reserves that you mentioned earlier in your testimony?

A. For electric plant, the amounts we will address are summarized on Exhibit ___ (DP-3). This Exhibit indicates that for total electric plant as of December 31, 2020, the Accumulated Provision for Depreciation per books, or book reserve, amounted to approximately $7.342 billion. The computed or theoretical reserve based on existing rates was calculated on the average service lives, net salvage percentages and life tables currently in use by the Company and amounted to approximately $9.584 billion. The computed reserve recommended in the Depreciation Study amounted to approximately $10.028 billion.

This Exhibit also indicates that the book reserve is approximately $2.242 billion, or 23.39 percent less than the computed reserve based upon existing rates and is approximately $2.686 billion, or 26.78 percent less than the computed reserve based upon the rates recommended in the Depreciation Study.

Q. Please continue with gas plant.

A. For gas plant, the amounts we will address are also summarized on Exhibit ___ (DP-3). This Exhibit indicates that for total gas plant as of December 31, 2020, the book reserve amounted to approximately $1.749 billion. The computed reserve based on existing rates was calculated on the average service lives, net salvage percentages and life tables currently in use by the Company and amounted to approximately $2.089 billion. The computed reserve recommended in the Depreciation Study amounted to approximately $2.692 billion.

This Exhibit also indicates that the book reserve is approximately $340.5 million, or 16.30 percent less than the computed reserve based upon existing rates and is approximately $943.7 million, or 35.05 percent less than the computed reserve based upon the proposed rates.

However, as discussed previously, the Company’s proposal is for a more moderate recognition of the impact of the CLCPA. The resultant theoretical reserve and reserve variation from this proposal is summarized in Exhibit ___ (DP-5). The computed reserve for this scenario is $2.442 billion and the book reserve is approximately $693.5, or 28.29% less than the computed reserve based on the depreciation parameters used for the Company’s revenue requirement in this case.

Q. Please continue with common plant.

A. For common plant, the amounts we will address are also summarized on Exhibit ___ (DP-3). This Exhibit indicate that for total common plant as of December

31, 2020, the book reserve amounted to approximately $1.180 billion. The computed reserve based on existing rates was calculated on the average service lives, net salvage percentages and life tables currently in use by the Company and amounted to approximately $1.256 billion. We have not recommended any changes to service lives or net salvage factors for common plant and as a result the computed reserve recommended based on the recommendations in the depreciation study is the same $1.256 billion.

This Exhibit also indicates that the book reserve is approximately $75.7 million, or 6.03 percent less than the computed reserve based upon both proposed and existing rates.

Q. Do you have a recommendation regarding the reserve variations?

A. Yes. For common plant, we recommend no action be taken related to the reserve variations, at the levels indicated, at this time. The NYPSC’s typical practice is to take no remedial action when the book reserve varies from the theoretical reserve by less than 10% (plus or minus). The variation for common plant falls within that range.

For electric plant, the Company proposes that the reserve deficiency that exceeds 10% of the theoretical reserve be recovered over a 20-year period and that the current recovery of Hudson Avenue continue. To calculate the recovery amount for the electric reserve deficiency, we first adjust the reserve deficiency to remove the remaining amount to recover for Hudson Avenue, which reduces the reserve deficiency to $2.624 billion. The amount that exceeds 10% of the theoretical reserve is $1.621 billion, which amortized over 20 years results in an annual recovery of $81.1 million. We propose that this amount replace the current $71.3 million annual recovery from Case No. 19-E-0065 and $11.6 million recovery from Case No. 16-E-0060. In addition, the current amortization of $3.8 million for Hudson Avenue should continue, resulting in a total annual recovery of $84.9 million. This is generally consistent with the approach from prior cases for the Company.

For gas plant, we recommend that the full reserve variation amount be recovered over a 20-year period. The estimated reserve variation for gas plant differs from the theoretical reserve by more than 10%, which indicates a need for remedial action. Even if they did not, this recovery period would be appropriate in light of the factors discussed in the previous section related to the CLCPA. Absent any action to address the reserve variation, if decarbonization does result in the loss of customers and shorter service lives, then the Company would not have the opportunity to recover the full costs of its assets over their service lives. Even if cost recovery were deferred, the result would be future customers paying for assets that are already retired, which would result in intergenerational inequity.

However, as discussed previously, to mitigate the overall impact to customers, the Company's proposal is to recover the gas reserve deficiency that exceeds 10% of the theoretical reserve over 20 years. The portion of the gas reserve deficiency from Exhibit ___(DP-5) that exceeds 10% of the theoretical reserve is $449.1 million. Amortizing this amount over 20 years results in an annual recovery of $22.5 million. We propose that this amount replace the current $8.0 million recovery established in Case No. 19-G-0066.

VI. ADVANCED METERING INFRASTRUCTURE ("AMI")

Q. Please discuss the Company's recovery of its investment in “legacy” meters due to the implementation of its AMI program.

A. AMI is a technology for improving efficiencies related to meter reading and providing other system and customer benefits. These initiatives involve installing electric “smart meters” across Con Edison’s service territory, resulting in the phasing-out of the older, “legacy” technology (*i.e.*, electro-mechanical and solid state meters) before they are fully depreciated. The Company began deploying AMI meters in 2017 and expects to complete the initiative in 2023. In the Joint Proposal in Cases 16-E-0060 and 16-G-0061, the parties agreed that (p. 51) “[t]he currently effective depreciation rates for electro-mechanical and solid state electric and gas meters will apply during the AMI deployment period. Any remaining undepreciated investment in the legacy meters will be amortized over a 15-year period.”

Q. What is the Company’s proposal regarding the recovery of the remaining book cost for electric meters that have been and will be retired due to the implementation of AMI?

A. Consistent with the Joint Proposal in Cases 16-E-0060 and 16-G-0061, the Company proposes begin amortizing the remaining undepreciated investment in legacy meters upon completion of the program. The AMI program is currently scheduled to be completed by 2023. As a result, as discussed further in the testimony of the Accounting Panel, the Company’s proposal conservatively begins the amortization of the unrecovered investment in 2024.

Additionally, it is our understanding that a relatively small number of meters will remain in service at the completion of the AMI program. The recommended depreciation rate for the small number of legacy meters that will remain is based on a 20-year average service life, which is the same average service life that had been used for solid state meters and is currently used for AMI meters.

Q. Does this conclude your direct testimony?

A. Yes, it does.

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.

CLIMATE LEADERSHIP AND COMMUNITY PROTECTION ACT PANEL

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I. Panel Introduction

A. Panel Introduction and Qualifications of Panel Members

Q. Would the members of the Panel please state their names and business addresses?

A. Yes. Patrick G. McHugh, Katherine Boden, Milovan Blair, Leonard P. Singh, Gurudatta Nadkarni, Christopher Ivan Kimball, Christopher Raup, and Venetia Lannon. The business address for each panelist is 4 Irving Place, New York, NY 10003.

Q. By whom are you employed, in what capacity, and what are your backgrounds and qualifications?

A. (McHugh)

I am Patrick G. McHugh, Senior Vice President of Electric Operations. I assumed this responsibility in July 2021, after serving as Vice President of Engineering and Planning for Con Edison. I currently have overall responsibility for Con Edison’s Electric Distribution Operations, Engineering and Planning, and Con Edison’s Energy Services organization, which coordinates all aspects of the delivery of electric service to customers.

I have been with the Company for over 30 years after joining in 1991 as a Management Intern, and have held various positions with increasing responsibility including Vice President of Engineering and Planning, Vice President of Brooklyn/Queens Electric Operations, Chief Engineer of Distribution Engineering, General Manager Protective Systems Testing, Senior System Operator, and Chief District Operator. I hold a Bachelor of Science degree in electrical engineering from Clarkson University, a Bachelor of Arts degree in physics from Plattsburgh State University, and a master's degree in electrical engineering from Clarkson University. I have also completed the Siemens PTI Transmissions course.

(Boden)

I am Katherine Boden, Senior Vice President of Gas Operations for Con Edison. I am responsible for the overall Con Edison Gas Operations, Engineering, and Compliance and Quality Assessment groups, within Gas. I joined Consolidated Edison in 1990 as a Management Intern. I have held various positions of increasing responsibility in Construction, Operations, and Engineering in Electric Operations. In 2005, I was promoted to Vice President Manhattan Electric Operations, a position that I held through 2010. In 2010 I was assigned to Gas Operations as

Vice President. In 2017, I was assigned to Gas Engineering as Vice President. In 2021, I was promoted to my current position as Senior Vice Present Gas Operations.

I hold a bachelor's degree in Electrical Engineering from Polytechnic University, and a Master of Business Administration in Management from Hofstra University. I also completed PTI's Power Technology Course, PTI's Electric Distribution System Engineering Course, and Gas Technology Institute's (GTI) Registered Gas Distribution Professional Course. I sit on the Board of Solar One, the Board of the Institute of Gas Innovation Technology (I-GIT) at Stony Brook University, the Board of the Northeast Gas Association and am a member of American Gas Association Leadership Council. I am engaged in several R&D initiatives, most notably the EPRI-GTI Low Carbon Resources Initiative.

(Blair)

I am Milovan (Milo) Blair, Senior Vice President of Central Operations for Con Edison. My responsibilities include the planning, design, operation and maintenance (O&M) of the Company's electric transmission system, substations, primary control center, electric and steam generating plants, and steam distribution system. I am also responsible for the Company’s engineering and construction activities. I joined Con Edison in 1991 as a Management Intern and have served as General Manager, Substation Operations-Northern region, General Manager, System Operations; Vice President, System and Transmission Operations and Vice President Brooklyn/Queens Electric Operations.

I hold an MBA in Information Systems from St. John’s University and a Bachelor of Science degree in Electrical Engineering from the City University of New York. I have completed the Senior Executive Program at Columbia University and the Siemens PTI Power Technology course. I currently serve on the executive board of the YMCA Bedford Stuyvesant Chapter and as a leadership council member of the City College of New York Grove School of Engineering.

(Singh)

I am Leonard P. Singh, Senior Vice President of Customer Energy Solutions at Con Edison, a position I have held since 2021. I lead a team responsible for distributed resource integration into infrastructure planning, battery storage, energy efficiency, rate design, heating electrification and electric vehicle initiatives, non-wires and non-pipeline solutions, utility of the future, as well as the implementation of the Company’s smart meter program, its new customer information system, the integrated data energy resource, and data access framework. Prior to my current position, I held numerous positions in operations and engineering across the Company’s three commodities (Electric, Gas, and Steam) since joining the company in 1991, including an operating supervisor, Construction Manager, Chief Engineer, General Manager and Vice President, with increasing responsibility and breadth. I hold a Bachelor of Science in Electrical Engineering from Massachusetts Institute of Technology, Master of Science in Electrical Engineering from Brooklyn Polytechnic University, and a Master of Business Administration from Columbia University.

(Nadkarni)

I am Gurudatta Nadkarni. I am employed by Con Edison and currently hold the position of Vice President, Strategic Planning. I am responsible for the Company’s long-range planning, climate risk and resilience, strategic initiatives, and mergers and acquisitions efforts. The most recent Long-Range Plans were completed January 2022. Before joining Con Edison, I held a number of positions in corporate strategy and development including Managing Director of growth at Duke Energy and a management consultant at McKinsey & Company. I was also a Senior Research Scientist at International Paper. I graduated from Vassar College with a Bachelor of Arts degree in Physics and Mathematics-Computer Science. I earned Master of Science degrees in Physics and Colloid, Polymer and Surface Science, and a Ph.D in Physics from Carnegie Mellon University. I also earned a Master of Business Administration degree in Finance and Marketing from the University of Chicago. I joined Con Edison as Vice President, Strategic Planning in 2008.

(Kimball)

I am Christopher Ivan Kimball, Vice President of Energy Management, a position I have held since July of 2012. I joined Con Edison in 1987 as a Management Intern and held various positions of increasing responsibility. In December 1998 I was transferred to Consolidated Edison Energy, Inc. ("Con Edison Energy") as Director of Asset management where my responsibilities included day-to-day scheduling, fuel procurement, electricity market sales and planning, and associated regulatory and accounting matters of generating facilities owned by Consolidated Edison Development, Inc. ("Con Edison Development") and other contracted generating facilities. In August 2008, I returned to Con Edison as Director of Electricity Supply, responsible for day-to-day electricity supply operations, including the scheduling of generation and load bids with the New York Independent System Operator ("NYISO") and neighboring control areas; developing the overall electric power procurement plans for full service customers; developing and implementing Con Edison's electric hedging program; strategically evaluating and participating in capacity and transmission congestion contract ("TCC") auctions; managing contractual rights with various non-utility generators; and processing monthly invoices for wholesale purchases and sales of capacity, energy, and TCCs for Con Edison and its affiliates, Orange and Rockland Utilities, Inc. ("ORU") and Rockland Electric Company ("RECO").

I hold a Bachelor of Science degree and a Master of Science degree in Nuclear Engineering from Rensselaer Polytechnic Institute.

(Raup)

I am Christopher Raup, Vice President, Energy Policy and Regulatory Affairs (EPRA). In my current position, as of January 1, 2022, I oversee the State Regulatory Affairs and Energy Markets Policy Group, with responsibility for managing the regulatory relationship with our state utility regulators (the New York Public Service Commission and the New Jersey Board of Public Utilities) and federal economic regulator (the Federal Energy Regulatory Commission). The EPRA team also represents the Company at business meetings of the two independent system operators which the Company participates in (NYISO and PJM, Inc.) and coordinates the development and advocacy of energy policy positions for the Company, for example, our efforts to participate in the Climate Leadership and Community Protection Act ("CLCPA") implementation process. I have over 20 years of utility industry experience in a variety of positions of increasing responsibility, including from 1996 through 2004, working at KeySpan Energy as a compressed natural gas ("CNG") station designer, CNG station operations manager, and project specialist in Strategic Planning; and since 2006, working at Con Edison as a project specialist in the Energy

Markets Policy Group, project manager and, later, director in State Regulatory Affairs, project manager and, later, director in the REV Demonstration Projects group, and director in the Utility of the Future group.

I hold a Bachelor of Engineering degree in Mechanical Engineering from The Cooper Union for the Advancement of Science and Art in New York City, and a Master of Business Administration from the Rotterdam School of Management in the Netherlands.

(Lannon)

I am Venetia Lannon, Vice President, Environment, Health and Safety. I joined Con Edison in April 2021. Prior to joining the Company, I was Vice President at Matrix New World Engineering, with market development responsibilities including climate adaptation services with a focus on nature-based systems for waterfront facilities, green infrastructure, and renewable energy. Before joining the private sector, I spent 20 years in public service most recently as former Governor Cuomo's Deputy Secretary for the Environment. In this capacity, I served as environmental policy advisor to the Governor and his cabinet and oversaw the operations of the state’s environmental agencies, including the Department of Environmental Conservation ("DEC"), the Office of Parks Recreation & Historic Preservation, the Environmental Facilities Corporation and the Adirondack Park Agency. Previously, I was appointed by former Governor Cuomo as Regional Director for the DEC, overseeing 200 staff and all aspects of the DEC's work in New York City. Prior to that, I held several positions working for the City of New York, as a Senior Vice President of the New York City Economic Development Corporation ("EDC") and as Deputy Director of the Recycling Bureau at the New York City Department of Sanitation, was responsible for the composting program.

I hold a Bachelor of Arts degree from Vassar College and a master's degree in public administration, focusing on environmental policy, from Columbia University.

B. Testimony Purpose and Format

Q. What is the purpose of your testimony?

A. Our purpose is to discuss Con Edison's support for the clean energy transition and to demonstrate that the Company's rate filings are consistent with and otherwise comply with the requirements of the CLCPA applicable to utility rate cases. In making this showing, we summarize the investments and programs the Company is proposing in this filing to help the State achieve CLCPA requirements, as well as the Company's existing efforts to contribute to meeting CLCPA goals. We also calculated emissions reductions associated with our clean energy investments and emissions associated with our electric and gas delivery volume forecasts, which show that the electric and gas filings are directionally consistent with the CLCPA at this early stage of its implementation.

Q. Please briefly summarize Con Edison's approach to climate change.

A. Con Edison is addressing climate change through a two-pronged approach: mitigation and adaptation. We aim to mitigate climate change by:

- Building a grid that facilitates delivery of 100% clean energy by 2040, targeting net-zero emissions by 2040;
- Decarbonizing and reducing the use of fossil natural gas, and pursuing new opportunities to use our gas system to help achieve CLCPA objectives; and

- Engaging our customers in the clean energy future with increased energy efficiency program offerings; development of electric vehicle charging infrastructure; innovative heating electrification program offerings; and programs to increase distributed energy resource offerings for customers, particularly low-and-moderate customers and those residing in disadvantaged communities.

We are also adapting our system to reliably serve customers under projected future atmospheric conditions (for example, higher temperatures) that are the result of expected climate change. This includes enhancing our ability to withstand and recover from more severe and frequent extreme weather events, as discussed in more detail in the Electric Storm Response and Resilience and Electric Infrastructure and Operations Panels. Accordingly, this testimony is focused on, with respect to the CLCPA, our efforts to mitigate climate change as reflected in this rate filing.

Q. Please describe how the remainder of this testimony is organized.

A. The testimony below is organized as follows:

- Section II describes Con Edison’s support for a clean energy future and the CLCPA
- Section III covers the long-term impact of the CLCPA on our business
- Section IV discusses proposed investments and programs in this rate case that further the CLCPA
- Section V discusses the CLCPA requirements applicable to utility rate cases.

II. Con Edison’s Support for Clean Energy and the CLCPA

A. Con Edison’s Clean Energy Commitment

Q. Does Con Edison support New York State’s transition to clean energy?

A. Yes. Con Edison is all-in on clean energy and has adopted a Clean Energy Commitment that sets forth its pledge to be a leader in the clean energy transition.

Q. Please explain Con Edison’s Clean Energy Commitment.

A. Con Edison is committed to investing in, building, and operating reliable, resilient, and innovative energy infrastructure, advancing electrification of heating and transportation, and aggressively transitioning away from fossil fuels to a net-zero economy by 2050 while being informed by principles of affordability, equity, and environmental justice. Our Clean Energy Commitment has five pillars:

1. **Build the Grid of the Future**: Build a resilient, 22nd century electric grid that delivers 100% clean energy by 2040.
2. **Empower All of Our Customers to Meet Their Climate Goals**: Accelerate energy efficiency with deep retrofits, aim to electrify most building heating systems by 2050, and go all-in on electric vehicles.
3. **Reimagine the Gas System**: Decarbonize and reduce the utilization of fossil natural gas, and explore new ways to use our existing, resilient gas infrastructure to serve our customers' future needs.
4. **Lead by Reducing Our Company's Carbon Footprint**: Aim for net-zero emissions by 2040, focusing on decarbonizing our steam system and other company operations.
5. **Partner with Our Stakeholders**: Enhance our collaboration with our customers and stakeholders

to improve the quality of life of the neighborhoods we serve and live in, focusing on disadvantaged communities.

Each pillar includes initiatives that identify current or proposed future Company programs. These initiatives may be viewed at this link: Our Clean Energy Commitment | Con Edison.[1]

Q. Does Con Edison review its Clean Energy Commitment?

A. Yes. The Clean Energy Commitment is a "living" document capable of being updated to reflect policy or technological changes.

Q. What past efforts has Con Edison undertaken that demonstrate its commitment to clean energy?

A. Con Edison has a history of promoting clean energy, including:

Energy Efficiency & Heating Electrification

Con Edison's energy efficiency programs have grown 21% since 2019, serving more than 600,000 customers in 2021. Its Clean Heat heating electrification program has grown by 354% since inception in 2020, reaching more than 9,500 customers and exceeding its program targets by more than

[1] https://www.coned.com/en/our-energy-future/our-energy-vision/our-energy-future-commitment

two-fold in 2021. The Company has recently expanded its programs that serve low-income customers, offering greater support and additional funding to support these customers in benefiting from the clean energy transition.

Electric Vehicles

The Company has two programs that promote Electric Vehicles (“EV”): the SmartCharge NY program and the PowerReady program. The SmartCharge NY program, launched in April 2017, incents EV drivers to shift to off-peak charging (past midnight) and thereby lessen the impacts of EV charging on the local grid. Approximately 15% of passenger EVs in our service territory have enrolled in SmartCharge NY. The PowerReady program, launched in July 2020, provides incentives for make-ready infrastructure (both on the utility and customer side) to facilitate installing chargers, lowering the upfront cost of building chargers with higher levels of incentives available to customers in disadvantaged communities. The PowerReady program has resulted in the development of the largest public universal charging hub in the Americas in Brooklyn. PowerReady has set targets of 457 direct current fast charging and 18,539 level 2 in the Company's territory. Applications in and around disadvantaged communities have been robust.

Interconnection of Solar and Storage

Con Edison has a robust process for integrating distributed clean energy sources into its distribution system. We changed our network system design to safely allow power to flow back on the network system, which provided our grid the ability to interconnect and integrate Distributed Energy Resources ("DERs") onto our system. Through 2021, we have interconnected 398 MW of solar and 18 MW of storage. In addition, we participate in the Interconnection Policy and Technical Working Groups. The purpose of the Interconnection Policy Working Group is to explore policy and process issues relevant to the interconnection of distributed generation in New York. The goal of the Interconnection Technical Working Group is to identify, discuss, and resolve technical barriers and challenges associated with the DER interconnection process and the Standardized Interconnection Requirements in New York State in an efficient and effective manner.

Non-Pipes Alternatives (NPA)

Con Edison has advanced NPAs to defer or avoid traditional gas infrastructure in line with evolving Commission and State policy. In 2020, consistent with the terms of the current rate plan, the Company proposed a broad NPA Framework. While that filing was pending, the Company identified several promising NPAs. The Company made three important steps toward implementing NPAs in 2021. First, in July, the Company released an RFP for an Implementation Contractor for its Main Replacement NPA program and expects to select a vendor in Q1 2022. In December, the Company released RFPs for area projects in Soundview in the Bronx and Port Chester in Westchester. Finally, in December 2021, the Company petitioned the Commission for authorization to proceed with those three projects and one in Bayside Queens with specific accounting treatment and incentives.

Non-Wires Solutions (NWS)

The Company also supports clean energy through its NWS programs. The Brooklyn-Queens Demand Management (“BQDM”) program, the first “non-wires” program in New York State, began in 2014 and continues today to support peak demand reduction through customer-sided solutions that help defer traditional infrastructure upgrades. Since BQDM, the Company has launched two additional NWS programs: Water Street/Plymouth Street and Newtown. In 2021, the Water Street/Plymouth Street NWS portfolio achieved its goal of eliminating the need for the Company to install cooling and reconductoring upgrades through implementation of energy efficiency and distributed generation. The Newtown NWS remains an active portfolio with the goal of achieving 21 MW of peak load relief through energy efficiency and energy storage and deferring capital infrastructure upgrades in the area through 2024. Together with BQDM, these NWS programs have supported the installation of over 15 MW of distributed generation, including dispatchable energy storage in specific Brooklyn and Queens networks. The Company continues to evaluate new system expansion projects for pursuit as a Non-Wires Solution across its service territory.

Steam System

Consistent with the CLCPA, by 2040 Con Edison plans to decarbonize its East River cogeneration assets, which provide approximately 50 percent of the Company’s steam production, through low carbon fuels or carbon capture strategies. In addition, the Company plans to retire its five electric production gas turbine units as described in the Electric Infrastructure and Operations Panel testimony.

Company Emissions Reductions

Con Edison also leads by example. Between 2005 and 2020, we reduced our own carbon footprint by 54% (direct emissions), the equivalent of taking 500,000 vehicles off the road with respect to GHG emissions. In addition, in 2020 we released 98% less SF6 than in 1996, well ahead of our commitment in the 1999 memorandum of understanding with the U.S. Environmental Protection Agency (EPA). We also joined the EPA’s Natural Gas STAR Methane Challenge in 2016 with a goal to replace 4% of our cast iron and unprotected steel mains each year. Since 2017, have replaced 342 miles of this main, representing an average replacement rate of 4.5%. We continue to make progress in this area, and in support of the CLCPA, have joined the ONE Future Coalition to reduce industry methane emissions to 1% or less by 2025.

B. The CLCPA

Q. What is the CLCPA?

A. The CLCPA is New York State’s comprehensive climate change, clean energy, and environmental justice act. The CLCPA provides for reducing the State's GHG emissions economy-wide and seeks to improve the resiliency of communities across New York, as well as provide opportunities for residents and communities to partner with businesses, schools, and government to create a green economy and build a more sustainable future. The Act also provides that these goals will be achieved while adhering to environmental justice principles. The CLCPA seeks to achieve these outcomes by establishing GHG emissions limits, requiring specific amounts of renewable energy and other clean energy resources to be built, and mandating a certain portion of benefits be provided to disadvantaged communities.

Q. Please describe the CLCPA's clean energy requirements.

A. The CLCPA requires 70% of Statewide electric generation to be renewable by 2030 and 100% of Statewide electricity to be zero-emissions by 2040. In addition, the law requires the Commission to develop programs to procure 9 GW of offshore wind by 2035, and 6 GW of solar by 2025. While the law requires that 3 GW of energy storage be procured by 2030, the Governor has recently proposed to increase this goal to 6 GW of energy storage by 2030.

Q. Please describe the CLCPA's emissions reduction requirements.

A. The CLCPA establishes Statewide emissions reduction targets of: (1) 40% from 1990 levels by 2030; (2) 85% from 1990 levels by 2050; and (3) a goal of net zero emissions economy wide by 2050.

Q. Please explain the CLCPA's disadvantaged community requirements as they apply to utility rate cases.

A. Our understanding from counsel is that the Commission has determined that the CLCPA prohibits it from approving a rate plan that disproportionately burdens disadvantaged communities. As part of this analysis, the Commission will also evaluate if the approved rate plan provides benefits to disadvantaged communities.

Q. Does Con Edison support the CLCPA's clean energy and disadvantaged community requirements?

A. Yes, and as discussed later in this testimony, Con Edison's rate filing proposes electric and gas rate plans that enable the Commission to determine that the rate plan complies with the CLCPA review requirements applicable to utility rate cases because they are fully consistent with CLCPA goals (to the extent known) and principles.

Q. Why do you say to the extent known?

A. As the Commission noted in *National Grid*[2] and confirmed in Niagara Mohawk,[3] "[t]he CLCPA is still a nascent law whose implementation remains a work-in-progress in the State, albeit an important one."

Q. What is the Climate Action Council?

A. The Climate Action Council is the committee created by the CLCPA that is charged with developing a draft and final Scoping Plan of recommendations to meet the law's requirements and targets.

Q. What is the status of the Climate Action Council's Scoping Plan?

A. The Council released a draft Scoping Plan on December 30, 2021, noting that the draft is for public review and does not carry the Council's formal endorsement. The draft

[2] Case 19-G-0309 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of The Brooklyn Union Gas Company d/b/a National Grid NY for Gas Service*, Order Approving Joint Proposal, As Modified, And Imposing Additional Requirements (Aug. 12, 2021) at 71 (*National Grid*).

[3] Case 20-E-0380 et al., *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation d/b/a National Grid for Electric Service*, Order Adopting Terms of Joint Proposal, Establishing Rate Plans and Reporting Requirements (Jan. 20, 2022) at 78 ("[I]mplementation of the CLCPA remains a work in progress.")(*Niagara Mohawk*).

Scoping Plan states that, as required by the CLCPA, the Council will hold regional public hearings. In addition, the public has 120 days from January 1, 2022 to comment on the draft. The Council will then evaluate the input it receives, determine whether to revise the draft, and issue the final Scoping Plan. The final Scoping Plan is to be released no later than January 1, 2023.

Q. Has the Department of Environmental Conservation (DEC) adopted climate regulations applicable to the utility sector?

A. No. DEC must promulgate regulations by January 1, 2024. State agencies, including the Commission, will work with DEC to promulgate the necessary regulations.

Q. What does the early stage of CLCPA implementation mean for Con Edison?

A. It means that the full picture of what ultimately will be required for CLCPA compliance is not yet clear and depends on decisions of uncertain timing.

Q. What is Con Edison doing in the interim?

A. Con Edison recognizes its crucial role in developing the infrastructure required to facilitate renewable power and storage and to enable increased electrification of heating and transportation. And, as we explain herein, our rate filing reflects this recognition. For example, the Company is proposing emissions mitigation measures as part of these proceedings, planning the electric infrastructure needed to facilitate the achievement of Statewide clean energy goals, including the Reliable Clean City Projects and Gateway Park Area Substation, and investing hundreds of millions of dollars in its nation-leading customer programs to enable participation in the clean energy future. Under current Commission policy, Con Edison is not allowed to build and own electric generation so we cannot play a direct role in achieving the CLCPA's electric generation goals. We note, however, that we believe the Commission should allow us to have a role in achieving these ambitious goals and have included in this filing an innovative solar generation proposal to fund low-income discounts.

III. The CLCPA's Impact Con Edison's Businesses

Q. Do you foresee potential changes to Con Edison's businesses because of the CLCPA's clean energy requirements and the clean energy transition?

A. Yes. We anticipate a decrease in fossil fuel gas consumption and an increase in electric usage driven by building and transportation electrification. We also foresee a shift from fossil fuels to renewable electric generation and low carbon energy sources, and an increased emphasis on demand response, energy efficiency, distributed energy resources, energy storage, and innovative system designs to manage system and customer needs.

A. The CLCPA’s Impact on Long-Term Planning

Q. How is Con Edison planning to prepare for the clean energy future?

A. In order to meet the CLCPA’s clean energy requirements and Con Edison’s Clean Energy Commitment, we have developed Long-Range Plans that examine three possible future pathways to 2050. Each pathway examines a different potential scenario for electrification and adoption of low carbon fuels, which allows us to understand the type of investment decisions we would need to make in each scenario. Regardless of which pathway we pursue in the future, the initial 10 years are consistent and can be reflected in our current 10-year plans and include key investments foundational to the businesses and the clean energy future, including energy efficiency, heat pump incentive programs, and main replacement. This approach allows us to remain flexible and find the best approach for our customers.

Q. Please elaborate on the areas covered by your Long-Range Plan.

A. The Long-Range Plan covers:

- Transmission and distribution infrastructure needed to integrate clean energy sources like offshore and onshore wind, utility scale solar, and distributed resources;
- Infrastructure and programs required for more utility and customer energy storage;
- Investment in community renewable generation to serve our low-and moderate-income customers and more broadly for utility owned renewable generation;
- Supporting R&D efforts in production, transport, and storage of low carbon fuels and integrating them into our existing energy infrastructure.
- Targeting emissions reduction on our gas system today, with continued replacement of leak prone mains.
- Accelerating energy efficiency programs to meet our goals

- Providing customers with financial incentives to electrify heating and transport and shift away from fossil fuel sources.

B. The CLCPA's Impact on Con Edison's Electric System

Q. Please explain how you think the CLCPA will affect Con Edison's electric system.

A. Our electric system is necessary to connect customers to the clean energy sources required to meet the CLCPA's renewable energy and emissions reduction requirements. Further, because of electrification, we expect that our system will experience increased usage and shifting peaks (but we do not expect the electric peak to shift from summer to winter until the end of the 2030s). Thus, we anticipate that the CLCPA and clean energy transition will require Con Edison to make significant investments in its electric transmission and distribution system to enable safe and reliable delivery of large-scale clean energy resources, such as offshore wind, and to accommodate increasing electrification and changes in customer use patterns.

C. The CLCPA's Impact on Con Edison's Gas System

Q. Please explain how you think the CLCPA will affect Con Edison's gas system.

A. We expect to see a decline in gas sales and in usage of our gas delivery system because of energy efficiency and electrification undertaken to help the State meet the CLCPA's clean energy and emissions reduction requirements. For details on the rate filing gas forecast please refer to the Gas Forecasting Panel.

Because we have an obligation to operate our gas system safely and reliably for our 1.1 million existing customers and the public as long as customers are served by the system, we will continue to make safety and reliability investments in our system. But we also note that, as briefly discussed below and further described by the Gas Infrastructure, Operations, and Supply Panel, we are the first utility in the State to propose steps to reduce gas connections such as asking the Commission to waive the revenue test and other customer allotments for new customer connections.

Q. Does the CLCPA permit Con Edison to make safety and reliability investments in its gas system?

A. Yes. In *National Grid* (p.80), the Commission explained that the CLCPA's required emissions reductions do not "override" the statutory mandate that utilities provide safe and reliable gas service at just and reasonable rates or the Commission's obligation to enforce this mandate. The Commission further explained that "[u]ntil technologies advance to a point where natural gas is no longer needed for heat and hot water, the Commission must ensure the reliability of gas delivery systems throughout the State" (p.74). To illustrate the stakes, the Commission cited the deaths and significant inconvenience caused by the long-term gas outages in Texas in the winter of 2021 as an example "of what can go wrong if gas supplies are suddenly halted during the coldest days of the year" (p.74). In *Niagara Mohawk* (p.80), the Commission confirmed that ensuring safe and adequate service remains its "core responsibility" and observed that "failure to maintain safe and adequate electric and gas systems throughout the [S]tate would undermine the intent of the CLCPA." Con Edison also regards safe and reliable service as its core responsibility and is directly subject to the statutory mandate referred to by the Commission.

Therefore, we will continue to propose investments necessary to keep the gas system safe and reliable.

Q. Can you further explain your approach to the gas system in light of the CLCPA?

A. Yes. Our approach is to operate the gas system safely and reliably and to continue reducing fugitive emissions, in particular methane emissions, from upstream sources of natural gas and our existing infrastructure, while we transition gas heating customers to electric heating where feasible and look for opportunities to pivot our existing gas assets to future cleaner usages.

Q. Why is the Company focusing on methane emissions?

A. Natural gas contains methane, a potent greenhouse gas, that once emitted into the air is 86 times more potent than carbon dioxide if modeled on a 20-year time frame, as provided for in the CLCPA. Methane is the largest component of natural gas and can be emitted during normal operating activities such as transportation, prior to combustion. The Company is committed to reducing these emissions whenever possible, including through its leak prone pipe program and proposed certified natural gas procurement pilot.

Q. Does replacing leak prone pipe really reduce methane emissions?

A. Yes. Per our annual reporting to the EPA, emissions from Con Edison's gas system have dropped over 50% since 1990 using the EPA methodology (See Figure 1 below). However, this methodology does not account for our leak backlog reduction, where actual leaks are repaired in a timely manner.

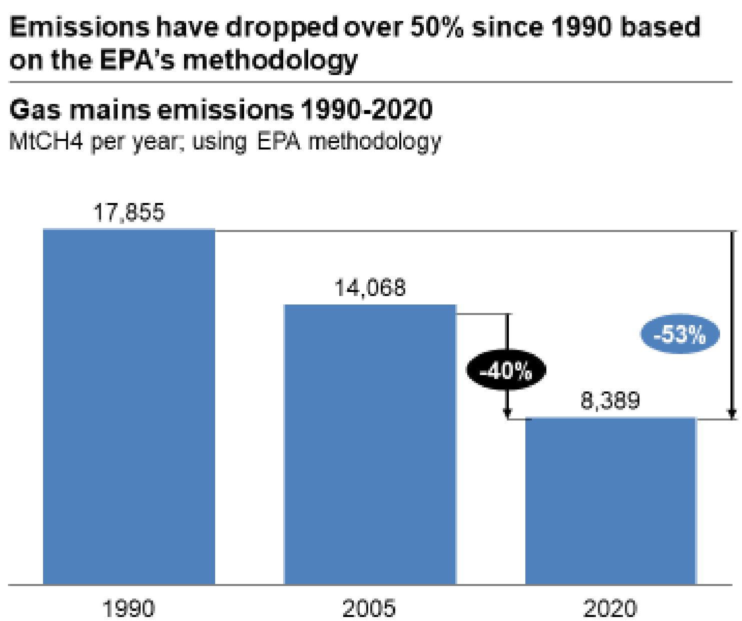

Figure 1: Cummulative emission reductions from gas main replacement (Source: Con Ed's Gas Distribution System Annual DOT Reports combined with the EPA's Subpart W Greenhouse Gas Reporting Program)

Q. Is Con Edison studying alternative fuels for distribution through its gas system?

A. Yes. Con Edison is participating in studies and collaboratives to understand the effects of hydrogen on our system. Some of these collaboratives include the EPRI/GTI collaborative called the Low-Carbon Resources Initiative (LCRI), the Center for Hydrogen Safety, and the Institute of Gas Innovation and Technology (IGIT) at Stony Brook University. We also support research into RNG and synthetic gas.

Q. Why are you studying alternative uses of the gas system?

A. Many studies show that in scenarios where the state achieves its decarbonization goals via electrification, peak load increases substantially and the system becomes winter peaking (as opposed to peaking in the summer, as it does today). The CLCPA Draft Scoping Plan, for example, shows peak electric load nearly doubling, and the electric system becoming winter peaking in 2035. Using the existing gas system to transport clean energy heating may reduce the need to make substantial investments in increasing electric transmission capability. The capability is there: currently the gas system transports three times the energy on a peak winter day than the electric system does on a peak summer day. A low carbon gas distribution system can continue to serve our customers, especially where electrification is difficult or cost prohibitive, contributes to resilience, and can help to mitigate what could otherwise be a costly buildout of the electric system. Additionally, the gas system is comprised of 4,400 miles of useful pipeline infrastructure and represents an embedded value from which future customers can and should continue to benefit, consistent with the CLCPA.

D. The CLCPA’s Impact on Interactions with Customers

Q. Explain how the CLCPA will affect Con Edison’s interactions with its customers.

A. Customers will play an important role in meeting CLCPA goals. Prior to the CLCPA, customers were already beginning to use technologies to reduce emissions through installing more efficient heat pumps in their homes, using electric vehicles, or installing their own energy resources such as rooftop solar. To assist our customers in continuing to adopt clean energy technologies, we will focus on providing resources and educational tools that allow customers to take full advantage of these technologies to decrease emissions. Additionally, the Company will provide additional resources to customers in disadvantaged communities so they can also benefit from the clean energy transition. Con Edison will also require additional infrastructure, both physical and IT, to integrate these new resources safely and reliably into the grid.

Q. Is Con Edison proposing investments in this filing to enhance customer engagement?

A. Yes. As described more fully by the Customer Energy Solutions Panel, the Company's proposed investments include: Customer Recommendations & Analysis tools, DER and heating electrification make-ready proposals, the Clean Energy Credit for Low-Income Customers, a solar smart inverter customer program, and an expansion of its Innovative Pricing Pilot.

IV. Clean Energy Investments and Program Proposals

A. Electric Investments and Programs

Q. What electric investments or programs is Con Edison proposing in this rate case to mitigate emissions and facilitate the State achieving its CLCPA goals?

A. As described more fully by the Electric Infrastructure and Operations Panel, over a three-year term, the Company is proposing:

Gateway Park Area Station

Con Edison plans to invest $250 million to begin construction of the Gateway Park Area Station, which will be supplied with renewable energy by the Brooklyn Clean Energy Hub. This project is needed to reliably electrify parts of Brooklyn and Queens, including disadvantaged communities.

Crown Heights Network Split

Con Edison is proposing to invest $12.5 million to split the Crown Heights network into two load areas to alleviate load growth expected to occur because of electrification. This network serves, in large part, disadvantaged communities. Switches will be installed so load can be shifted between these networks. Splitting the networks and installing switches so load can be transferred in Brownsville and Bensonhurst load areas increases the reliability and resiliency of the networks in the near and long term. The newly formed network will be supplied by the Gateway Park Area Station. The additional system capacity will facilitate the continued customer adoption of building and transportation electrification resources without negatively impact reliability.

Light Duty Electric Vehicle Charging Make-Ready Program

Con Edison is proposing to invest $114.3 million to fund the utility-side capital costs associated with EV charging station deployment.

New Business Capital

Con Edison is proposing to invest $573 million to expand the capability of the distribution system to support the connection of new load, including load for new buildings that are increasingly fully electrified to comply with Local Law 97.

Williamsburg Network Improvement

Con Edison is proposing to invest $65.3 million to create two smaller load areas out of the Williamsburg Network to de-load existing feeders and prepare the network to accommodate load growth from new business and electrification, while increasing reliability.

Primary Feeder Relief

Con Edison is proposing to invest $31.3 million in the reinforcement of primary distribution feeds that are projected to operate above their thermal ratings, in some cases because of increased temperatures and electrification.

Farragut(STATCOM)

Con Edison is proposing to invest $130 million for the establishment of a static synchronous compensator (“STATCOM”) at the Farragut Substation to address reliability needs driven by Fault-Induced Delayed Voltage Recovery caused by future load growth, including growth attributable to heating and transportation electrification, and the retirement of fossil fuel peaking units to reduce emissions.

Parkview TR5 and Feeder 38M85

Con Edison is proposing to invest $102 million for the establishment of a supply feeder from the Mott Haven Substation to the Parkview Substation. The capacity added through this project will accommodate anticipated load growth due to the expansion of the MTA’s 2nd Avenue Subway line and load growth related to building electrification.

Retrofit Over-Duty 13kV and 27kV Circuit Breaker Program

Con Edison is proposing to invest $41.4 million to replace several existing 13kV and 27kV circuit breakers that are currently not rated to interrupt maximum fault, supporting system integrity and facilitating the interconnection of clean distributed generation to the electric system.

Goethals Circuit Switcher

Con Edison is proposing to invest $10 million to establish a new 345kV SF6 circuit switcher at the Goethals 345kV Substation to address Fault-Induced Delayed Voltage Recovery issues related to load growth, including growth attributable to heating and transportation electrification, and the retirement of fossil fuel peaking units to reduce emissions.

Q. Does Con Edison have any previously approved electric system investments that mitigate emissions and facilitate the State achieving its CLCPA goals?

A. Yes. As discussed further by the Electric Infrastructure and Operations Panel, the Commission approved three Con

Edison transmission projects, collectively referred to as the Reliable Clean City Projects, that will allow high emission peaking generators to retire without compromising reliability. The Reliable Clean City Projects will also eliminate some transmission system constraints that would otherwise prevent renewable resources (such as new offshore or upstate wind) from reaching New York City customers.

Q. Why is Con Edison not proposing more electric transmission projects like the Reliable Clean City Projects in this rate case?

A. In the *Phase II Order*,[4] the Commission instructed utilities not to propose local transmission and distribution investments needed to meet CLCPA objectives in their individual rate cases. Instead, the Commission stated that it will establish a Statewide proceeding for utilities to submit "the portfolio of [local transmission and distribution] upgrades that they have determined, through the coordinated planning process [established by the

[4] Case 20-E-0197, *Proceeding on Motion of the Commission to Implement Transmission Planning Pursuant to the Accelerated Renewable Energy Growth and Community Benefit Act* (*Accelerated Renewable Act Implementation Proceeding*), Order on Local Transmission and Distribution Planning Process and Phase 2 Project Proposals (Sept. 9, 2021) at 29, 34 (*Phase II Order*).

Commission in the *Phase II Order*], support timely achievement of CLCPA targets and meet the relevant criteria and approved Benefit-Cost Analysis].” The Commission explained that “[s]uch a proceeding would allow for a holistic review of proposed projects and costs across the state and would also provide Staff and other interested parties opportunities to evaluate and comment on those proposals. Following the review of the project portfolio, the Commission would approve, modify, or reject proposed investments and determine the resulting revenue requirements, just as it would do in a rate case” (p. 29-30).

Q. Does Con Edison have any Phase II projects?

A. Yes.

Q. What are they and what is their status?

A. Con Edison has proposed Phase 2 transmission projects, which include “Clean Energy Hubs” for offshore wind and other new resources to connect and deliver power to New York City customers, aiding the State in meeting the CLCPA goal of 9,000 MW of offshore wind by 2035. These transmission projects will help future NYSERDA solicitations facilitate construction of offshore wind projects through the purchase of Offshore Wind Renewable Energy Credits and produce the most competitive, efficient results for all New Yorkers. On January 20, 2021, the Commission authorized Con Edison to file a comprehensive petition seeking approval of a Clean Energy Hub in Brooklyn.[5]

B. Gas Investments and Programs

Q. What gas investments or programs is Con Edison proposing in this rate case to mitigate emissions and facilitate the State achieving its CLCPA goals?

A. As described more fully by the Gas Infrastructure, Operations, and Supply Panel, over a three-year term, the Company is proposing the following investments and programs:

Main & Service Replacement Program

Con Edison is proposing to invest $404.8 million in RY1, $425.2 million in RY2, and $442.2 million in RY3 to continue to prioritize high risk pipe for replacement to support continued safe and reliable service for existing and future hard-to-electrify

[5] *Accelerated Renewable Act Implementation Proceeding*, Order on Power Grid Study Recommendations (Jan. 20, 2022) at 22.

customers and reduce fugitive emissions from this pipe, which is prone to leaking. The Company is also proposing to enhance methane reduction under this program while maintaining the focus on safety. Non-pipe alternatives and main elimination will also be considered as options to reduce the amount of high-risk pipe on the system.

Natural Gas Detection Devices

Con Edison is proposing to invest $97.1 million to continue installation of Advanced Metering Infrastructure-enabled natural gas detectors in homes and businesses throughout the service territory. These devices are constantly monitoring for methane and can detect gas leaks that the human nose may not. Because they are linked to our emergency response center through our Advanced Metering Infrastructure, we can respond to alarms in real time and quickly mitigate the amount of emissions release by isolating the source of the leak or making repairs.

Methane Capture Technology

Con Edison is proposing to invest $3 million in methane capture technologies as part of its commitment to eliminate emissions during routine operations. Tools, such as ZEVAC (Zero Emissions Vacuum), and others in development, allow the reliability work to continue while significantly reducing the release of methane into the environment.

Advanced Leak Detection

Con Edison is proposing to invest $1.5 million in advance leak detection technology while continuing efficient repair work. Leak detection technology continues to evolve and the Company is seeking to expand its use of advanced leak detection equipment to supplement the extensive work it already does to find leaking main and service pipes. The Company has some of the fastest response and repair times in the industry.

RNG Interconnection

Con Edison is proposing to invest $1.5 million to connect our first RNG facility in Westchester County. The Company will use this interconnection to facilitate other additional interconnection opportunities to our distribution system. RNG, and the use of certified gas, is another tool to reduce the gas system's climate change impact.

Certified Natural Gas

Con Edison is proposing to invest $800,000 to pilot the procurement of natural gas that is certified to have followed the best environmental practices. Certified natural gas is natural gas originating from producing sites that have undergone third-party certification to verify that the operator has met high environmental standards and best practices for methane emissions reduction in their operations.

Q. Is Con Edison taking any other steps to reduce emissions?

A. Yes. We are: (1) proposing to remove many financial incentives for new gas customer connections; (2) increasing our clean energy outreach and education for customers, contractors, and others; and (3) changing our design philosophy.

Q. Please describe the Company's proposal to eliminate financial incentives for new gas customer connections.

A. While the Public Service Law currently requires Con Edison to serve gas customers who request service, the Company's tariff provisions exceed the statutory requirements under the Public Service Law in several respects. In this filing, and as described more fully by the Gas Infrastructure, Operations, and Supply Panel, we are seeking to eliminate these "extra" tariff obligations by:

- Removing language in our gas tariff that allows multiple customers seeking to connect to the Company's gas distribution system to pool their main installation footage and avoid additional connection costs. Eliminating the "concurrent connections" tariff language will preclude sharing of benefits between customers who otherwise would exceed their individual allotment of main footage but for the fact that other customers connected at the same time and did not use their full allotment.
- Seeking a waiver of Commission regulations to permit us to eliminate the "revenue test" in the gas tariff. This would effectively eliminate an incentive to connect a new natural gas service by requiring new customers to pay the costs associated

with serving them beyond the 100 feet the Company must provide at no cost under Public Service Law. Rather than applying a “revenue test” that would potentially result in all customers initially absorbing this extra cost because it would be “paid for” through revenues shortly after the Company placed it into service, the new customer would now pay the extra costs up front.

- Seeking a waiver of Commission regulations to permit us to eliminate from the gas tariff full or partial reimbursement for customers who have paid for a main extension when other subsequent customers connect to the extension within five years.
- Seeking a waiver of Commission regulations to permit us to modify the gas tariff to provide the same main/service allotment to all new customers, regardless of customer type and usage.

Q. Please describe the Company’s proposal to increase its clean energy outreach and education.

A. The Company will educate customers on non-fossil energy options before accepting their work request for gas service. The Company intends to require that all customers affirm that they have been provided information on environmental regulations and non-fossil alternatives at the initiation of an application for gas service.

Q. Please describe the Company's changes to its gas system design philosophy.

A. In the recent past, the Company was converting many oil heating customers to natural gas. This customer growth often required the Company to upgrade the capacity of its distribution mains. With the transition to electrification, the company will maintain safe and reliable gas service for its existing customers but does not expect to be adding significant numbers of new customers. In recognition of increasing electrification, Con Edison has modified its design philosophy to generally end the upsizing of replaced mains for future growth. The Company has also begun the process of including NPA in its gas planning process and proposes a standardized process to facilitate effective implementation. The Company is also requesting funding for a forecasting tool to identify more opportunities, as described in the Gas Forecasting Panel testimony.

Q. Does Con Edison have any existing gas system investments or programs that mitigate emissions and facilitate the State achieving its CLCPA goals?

A. Yes. As mentioned earlier in Section II, in December 2021, the Company filed a petition with the Commission asking for approval of accounting and incentive treatment and authorization to proceed with a set of four NPA projects. The four projects include the Main Replacement Program (“MRP”) to potentially retire certain segments of main by electrifying customers currently receiving gas service from those mains, and three area projects, one each in Westchester, the Bronx, and Queens. The Customer Energy Solutions Panel proposes to facilitate the growth of this program by adopting a long-term framework that would cover future NPA projects.

C. Clean Energy Investments and Programs

Q. What clean energy investments or programs is Con Edison proposing to mitigate emissions and facilitate the State achieving its CLCPA goals?

A. As described more fully by the Customer Energy Solutions Panel, over a three-year term, the Company is proposing the following investments and programs:

DER Integration and Management

The Company proposes to invest $72 million in a DER Integration and Management Program to facilitate increasing amounts of DER in the Company’s service territory to help achieve CLCPA targets. This program includes investments in three areas; a)information system and operational software upgrades to better integrate DER into operations and planning processes, b)a Grid Edge technology environment to safely deploy and test nascent technologies, through partnerships with third party providers and research firms, in order to find grid edge solutions for the monitoring, control and optimization needs in higher DER penetration scenarios, and c) a smart inverter program that will leverage these capabilities and learnings to incentivize DER operations and performance at the grid edge. These investments will help streamline the process for customers to install distributed generation furthering adoption as called for by CLCPA by providing tools to allow DERs to connect to the grid and operate safely and efficiently.

Energy Storage

The Company proposes to invest $121.1 million in four Company owned energy storage equipment facilities at Company substations, adding 34MW/136MWh of capability to our system with 200 kW of clean energy generation. The energy storage systems augment traditional substation equipment and increase station capabilities by providing system support and rapid response to evening increases in energy drawn from the grid as distributed solar output declines. Project specific benefits include demonstrating new configuration to integrate EV chargers, solar, and storage more seamlessly, reducing the need for mobile stand-by diesel generators, and integrating with a 200kW PV array.

Clean Energy Credits for Low-Income Customers

The Company proposes to invest $200 million in a Clean Energy Credits for Low-Income Customers Program to create a source of revenues to fund incremental bill credits for customers who participate in our Energy Affordability Program. The revenue will be generated by Company-owned and operated solar generation in New York State outside Con Edison’s and Orange and

Rockland’s service territories. In addition to the benefits provided to participants in the Energy Affordability Program, the new solar generation will contribute to the CLCPA’s objective of renewable resources providing 70% of all power to the grid by 2030.

DER Make-Ready in Disadvantaged Communities

The Company proposes to invest $25.7 million in a DER Make-Ready Program to incentivize the installation of solar projects in disadvantaged communities or projects that benefit low- income customers by covering the customer’s utility upgrade costs. The DER Make-Ready program will support the distributed solar targets outlined in the CLCPA as well as encourage development of these resources in disadvantaged communities.

Heating Electrification Make Ready

The Company proposes to invest $76.6 million in a Heating Electrification Make Ready Program to enable greater adoption of space and water heating electrification technologies by providing incentives to customers facing the barrier of high cost of behind-the-meter electrical upgrades required to electrify.

Customer Recommendation and Analysis Tools

The Company proposes to invest $35 million in Customer Recommendation and Analysis Tools that will deliver an improved online experience by offering a suite of tools, refined by customer sector, to facilitate decision making and adoption of clean energy programs. This program will provide customers with a personalized and interactive experience that helps them better engage in the clean energy transition, and support contractors and third parties facilitate customer adoption of clean energy technologies.

Continuation of Clean Energy Earnings Adjustment Mechanisms

The Company proposes to continue earnings adjustment mechanisms for both electric and gas to encourage it to over-achieve on its targets to help customers reduce energy use, encourage the adoption of heat pumps, electric vehicles, and distributed energy resources, and reduce greenhouse gas emissions, in furtherance of the CLCPA’s goals.

Q. What clean energy investments or programs does Con Edison already have that are addressed in proceedings outside of this rate case?

A. As described by the Customer Energy Solutions Panel, the Company has the following existing programs that are addressed by proceedings outside of this rate case: the New Efficiency New York Energy Efficiency and Clean Heat (heating electrification) programs and the Electric Vehicle Charging Make-Ready program. The Company intends to seek authorization for incremental targets and budgets for its energy efficiency and heating electrification programs within the New Efficiency New York proceeding to accelerate achievement of the State’s clean energy goals. Further, the Company will work with Staff and stakeholders on any enhancements and changes to the EV make-ready program as well as those related to the Company’s managed charging program as part of the EV proceeding.

Q. Does the Company propose any changes to these programs within this rate case proceeding?

A. Yes. As discussed further by the Customer Energy Solutions Panel, the Company proposes to expand eligibility for its electric energy efficiency and heating electrification programs to customers served by the New York Power Authority who are currently excluded from participation.

D. Investments in Con Edison Facilities

Q. What clean energy investments is Con Edison proposing to its own facilities to mitigate emissions and facilitate the State achieving its CLCPA goals?

A. As described more fully by the Shared Services Panel, over a three-year term, the Company is proposing the following investments:

EV Charging Expansion

The Company proposes to invest $7.5 million to design and construct 75 Dual-Level 2 EV charging stations and 30 direct current fast charging vehicle charging stations to support fleets at Con Edison’s workout locations. This will support the Company’s addition of almost 500 electric vehicles by 2025 and further the Company’s vision of 80% light duty vehicle fleet by 2030 and 100% by 2035.

Facilities Energy Efficiency Program

The Company proposes to invest $49 million in various EE measures for its Irving Place Corporate Headquarters; Flatbush Avenue, Rye, and Davis Avenue

Regional Headquarters; and The Learning Center. These investments will reduce energy usage at Company-owned facilities and thereby eliminate GHG emissions directly attributable to Company operations.

E. Emissions Calculations

Q. Have you calculated the estimated emissions savings due to the Company's current and proposed clean energy investments and programs?

A. Yes. We estimate that these investments will result in emissions savings of 2,379,453 metric tons of carbon dioxide equivalent ("CO2e") over a three-year rate plan. The following table includes emissions savings by category and source.

Category	Source of CO_2e Reduction	Tons of CO2e Reduction (useful life varies by source)
Vehicles	Electric Vehicle Adoption	261,550
Heating	Heat Pump Adoption	65,395
Electric Consumption	Reduced Electricity Consumption (EE)	1,110,477
	Cleaner Sourced Electricity	290,287
	Conservation Voltage Optimization	163,765
Gas Consumption	Reduced Gas Consumption (EE)	487,981
Total		**2,379,453**

Q. How did you calculate these estimated emissions savings?

A. Con Edison calculated CO_2e reductions for electricity using the total output emission rate for NYC/ Westchester from

EPA's 2019 eGRID Subregion Output Emissions Rates table. The emissions rate for electricity used is 555 lbs of CO_2e per MWh avoided. The electricity emissions rate the Company used in its analysis does not take into account the expected decarbonization of the electric grid. It nevertheless illustrates that Con Edison's clean energy investments and programs are directionally consistent with CLCPA goals.

For avoided combustion of natural gas, Con Edison used 117 lbs of CO_2e per MMBTU of avoided combustion, based on data from EPA's GHG Emission Factors Hub. To calculate the CO_2e factor for natural gas, the Company first converted the nitrous oxide ("N_20") and methane ("CH_4") emission factors to units of CO2e by multiplying emission factors by each gas' respective global warming potential, and then summed the CO_2e factors for CO_2, N_20 and CH_4.

Q. Have other utilities used a similar approach?

A. Yes. Central Hudson and Orange and Rockland in their latest electric and gas rate cases, Cases 20-E-0428 and 20-G-0429 and Cases 21-E-0074 and 21-G-0073, respectively.

Q. Central Hudson and Orange and Rockland also estimated emissions associated with their electric and gas load forecasts. Did Con Edison do the same for informational purposes?

A. Yes. We applied the same aforementioned emissions rates above to the forecasted electric and gas delivery volume forecasts.

Q. Would you please summarize your estimated emissions associated with electric and gas delivery volume forecasts?

A. Con Edison estimated 14,113,095, 14,006,535, and 13,794,525 tons of CO2e emissions associated with its electric delivery volume forecast and 10,044,157, 10,131,820, and 10,039,648 tons of CO2e emissions associated with its gas delivery volume forecast for RY1, RY2, and RY3 respectively.

Q. Can you please elaborate on the emissions over the rate plan associated with the electric and gas delivery volume forecasts as shown in Exhibit_CLCPA-01?

A. This Exhibit generally shows that CO2e emissions are decreasing for delivered electric and are relatively flat for delivered gas over the 3-year rate plan. The primary reason for CO2e emissions reduction contained in electric forecast is energy efficiency. We note that the forecast includes the impact of the Company's energy efficiency programs, as well as organic energy efficiency.

Q. Are you sponsoring an exhibit that further explains the Company's emissions savings and load forecast emissions calculations?

A. Yes. Please see the exhibit entitled "CLCPA - 1."

MARK FOR IDENTIFICATION AS EXHIBIT ___ (CLCPA - 1)

Q. Was this exhibit prepared by you or under your direct supervision?

A. Yes

F. Other Con Edison Actions to Address Climate Change

Q. Earlier you mentioned that the Company has taken steps to adapt its' infrastructure to climate change. Please explain.

A. In 2019, Con Edison completed a Climate Change Vulnerability Study to determine how climate change might affect its operations and to recommend steps the Company can take to respond. In 2020, the Company filed a Climate Change Implementation Plan explaining how it would implement the Vulnerability Study's recommendations.

Q. Please explain how the Climate Change Implementation Plan is reflected in this rate case.

A. As part of the Climate Change Implementation Plan, Con Edison issued a new planning and design guideline. The design thresholds in the guideline incorporate climate variables that can be projected through currently available climate science.

For example, one climate variable is the increase in temperature due to climate change. The Company uses a metric to capture the impact of heat and humidity on our system. This measure is known as the temperature variable ("TV") and the current design criteria is 86 degrees Fahrenheit TV. The projected rise in heat and humidity is expected to result in a 1-degree TV rise each decade. As such, we have incorporated the projected TV in our plan.

Q. What are the consequences of incorporating the projected TV variable in the plan?

A. As discussed further by the Electric Infrastructure and Operations Panel, incorporating the projected TV has affected the Company's load forecast and network reliability model, resulting in a higher load forecast and the increased likelihood for cascading network outages. As that Panel explains, we are proposing investments in our electric infrastructure to maintain the level of service customers require.

Q. Can you give an example?

A. Yes, our Primary Feeder Reliability program. The Company uses the Network Reliability Index ("NRI") to gauge the reliability and resiliency of all 84 networks on its distribution system. The lower the index, the less likely the network is to experience cascading feeder outages. In accordance with its Climate Change Implementation Plan, Con Edison raised the TV in its NRI analysis to account for projected climate change. Raising the TV has a direct impact on NRI, particularly as it relates to heat stress, and results in the need for significant investment to maintain current NRI levels on all networks. As a result, and as discussed by the Electric Infrastructure and Operations Panel, we are proposing to invest $231M in our Primary Feeder Reliability program.

V. Required CLCPA Reviews

Q. What CLCPA requirements are applicable to utility rate cases?

A. We have been advised by counsel that CLCPA sections 7(2) and 7(3) apply to utility rate cases.

Q. What do those sections of the CLCPA require?

A. As we understand from counsel, CLCPA section 7(2) requires the Commission to consider whether its decisions are “inconsistent with or will interfere with” attaining Statewide greenhouse gas emissions limits and that section 7(3) requires the Commission to find that its decisions will not disproportionately burden disadvantaged communities.

A. Emissions Review

Q. Are Con Edison’s rate filings consistent with the CLCPA’s emissions goals?

A. Yes. The Commission approved the rate settlement in *Central Hudson* (pp. 43-44) as consistent with the CLCPA because it was a “significant and necessary step in reaching the CLCPA and other climate related requirements” and it approved the rate settlement in *Niagara Mohawk* (p.83) because it “appropriately balance[d] the interests in reliability, public safety, and reasonable rates with emission reductions and clean energy objectives” and was “an important step in the ongoing process of achieving the CLCPA’s greenhouse gas limits, one that will be built upon in future rate cases and other Commission proceedings.”

Our proposed rate plans contain investments, programs, and commitments, which we have summarized in this testimony, similar to those the Commission found to be consistent with the CLCPA in *Central Hudson* and *Niagara Mohawk*. Moreover, our proposals are important steps in the ongoing process of implementing the CLCPA because they enable electrification of heating, promote energy efficiency and electric vehicles, reduce methane emissions, and maintain safety and reliability, which are all required to meet the CLCPA's goals. As explained earlier in this testimony and more fully by the relevant panels, the clean energy investments and emissions-reducing activities identified in this testimony provide significant emissions savings. In addition, our proposed rate plans create a strong foundation for the Company and the Commission to build on in future rate cases and other Commission proceedings because they further institutionalize the Company's commitment to clean energy and establish benchmark programs and projects for the Commission and the Company to evaluate when considering next steps in the ongoing process of CLCPA implementation. Finally, and as explained more fully by the Electric Infrastructure and Operations Panel and Gas

Infrastructure, Operations, and Supply Panel, the projects and programs funded by Con Edison's rate filing are needed for safe and reliable service. For example, our electric projects address reliability issues arising from increasing electrification and projected climate change and our gas projects address or prevent methane leaks that can create a safety risk and harm the environment. In *National Grid*, the Commission cited safe and reliable service as a reason justifying new infrastructure, even considering the CLCPA, and in *Niagara Mohawk* (p.80) the Commission confirmed that failure to maintain safe and reliable service "would undermine the intent of the CLCPA."

B. Disadvantaged Communities

Q. Do Con Edison's rate filings disproportionally burden disadvantaged communities?

A. No. On the contrary, the Company's proposals provide overall benefits to disadvantaged communities, including because they are needed for safe and reliable service at reasonable rates, which the Commission cited in *National Grid* as important to disadvantaged communities.

Q. How might a project benefit a disadvantaged community?

A. Among other ways, a project could benefit a disadvantaged community because: (1) it is necessary to maintain safe and reliable service; (2) it facilitates access to clean energy; (3) it will maintain access to low-cost energy; (4) it will facilitate electrification; or (5) it will help reduce emissions, including by replacing leak-prone gas main, by permitting the retirement of an existing facility with a greater negative impact, or through some other means. As summarized in this testimony and as more fully explained by the Electric Infrastructure and Operations Panel, Gas Infrastructure, Operations, and Supply Panel, and Customer Energy Solutions Panel, Con Edison's proposed projects benefit disadvantaged communities in one or more of these ways.

Q. Please explain why Con Edison's rate filings provide an overall benefit to disadvantaged communities.

A. In this rate case Con Edison continues to maintain a focus on investments and programs required to provide disadvantaged communities with safe and reliable service at just and reasonable rates.

In addition, Con Edison is proposing investments highlighted in this testimony that benefit disadvantaged communities by reducing emissions in those communities and facilitating the clean energy transition, including:

- DER Make-Ready for Disadvantaged Communities will provide incentives to cover customer’s utility upgrade costs for clean energy projects located in disadvantaged communities.
- Heating Electrification Make Ready proposes higher incentives for LMI-qualifying buildings. These proposed higher incentives cover up to 100% of the expected cost of behind-the-meter electrical upgrades to enable heating electrification, removing a barrier to electrification, and enabling the electrification of LMI-qualifying buildings.
- Gateway Park Area Substation will allow the company to create smaller, more resilient, network areas that will directly benefit the reliability throughout the outer boroughs of Brooklyn and Queens that include disadvantaged communities. Additionally, the capacity created through this investment will allow for a greater portion of offshore wind to be delivered within this area of the Company’s service territory.

- NYPA Eligibility for Energy Efficiency Proposal will expand eligibility for EE and heating electrification programs to NYPA customers, many of which are key institutions serving disadvantaged communities (*e.g.*, schools, housing facilities, community centers, transit depots, and first responder centers).

In addition, as discussed more fully by the Electric Infrastructure and Operations Panel, the Company is proposing a Selective Undergrounding Program. The Selective Undergrounding Program will identify and prioritize sections of Con Edison’s overhead distribution system for potential undergrounding. The program will mitigate the scale of outages, minimize long-duration, low customer impacted outages, and make the Con Edison system more resilient. The program will incorporate disadvantaged community data into the prioritization model that will determine locations for undergrounding.

Finally, through the statewide NENY proceeding, Con Edison will continue to offer energy efficiency and heating electrification programs that offer expanded incentives to low-income customers and multi-family buildings that house low-income customers.

Q. Does this end your testimony?

A. Yes.