nationalgrid

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May 29, 2018

VIA ELECTRONIC DELIVERY

Honorable Kathleen H. Burgess
Secretary
New York State Public Service Commission
Three Empire State Plaza, 19th Floor
Albany, New York 12223-1350

RE: Case 15-E-0751 – In the Matter of the Value of Distributed Energy Resources

Matter 17-01277 – In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design

PROPOSALS OF THE JOINT UTILITIES ON RATE DESIGN SUCCESSOR TO NET ENERGY METERING FOR MASS MARKET CUSTOMERS

Dear Secretary Burgess:

In response to the December 22, 2017 *Revised VDER Value Stack and Rate Design Working Group Process and 2018 Schedule* from the New York State Department of Public Service Staff ("Staff")[1] and Staff's January 30, 2018 *Guiding Instructions to Utilities and Stakeholders on the Approach/ Implementation of Mass Market Rate Reform and Bill Impact Analysis* in the subject proceedings, Central Hudson Gas & Electric Corporation, Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation d/b/a National Grid, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation (collectively, the "Joint Utilities") hereby submit an overview (Attachment A), supported by two rate design proposals, entitled 2 Demand Rate and TOU Demand Rate (Attachments B-E and F-I , respectively, in PDF format), for Staff's consideration. Excel versions of the two rate design proposals are also enclosed.

Respectfully submitted,

/s/ Janet M. Audunson

Janet M. Audunson
Senior Counsel II

Enc.

cc: Marco Padula, DPS Staff, w/enclosure (via electronic mail)
Warren Myers, DPS Staff, w/enclosure (via electronic mail)
Theodore Kelly, DPS Staff, w/enclosure (via electronic mail)

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[1] The filing deadline for rate design proposals was subsequently extended by Staff and a new filing date of May 29, 2018 was established for all parties.

ATTACHMENT A

OVERVIEW

Attachment A
Overview

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of the Value of Distributed Energy Resources	))	Case 15-E-0751
In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design	))))	Matter 17-01277

PROPOSALS OF THE JOINT UTILITIES ON RATE DESIGN SUCCESSOR TO NET ENERGY METERING FOR MASS MARKET CUSTOMERS

On December 22, 2017, Department of Public Service Staff ("Staff") filed its *Revised VDER Value Stack and Rate Design Working Group Process and 2018 Schedule* ("Staff Process Document"),[1] which invited parties to submit proposals for rate designs that could serve as the basis for a mass market net energy metering ("NEM") successor tariff. On January 30, 2018, Staff issued the *Guiding Instructions to Utilities and Stakeholders on the Approach/ Implementation of Mass Market Rate Reform and Bill Impact Analysis* ("Guiding Instructions"), which provides context and guidance for such proposals.[2] Central Hudson Gas & Electric Corporation ("Central Hudson"), Consolidated Edison Company of New York, Inc. ("Con Edison"), New York State Electric & Gas Corporation ("NYSEG"), Niagara Mohawk Power Corporation d/b/a National Grid ("National Grid"), Orange and Rockland Utilities, Inc.

1 Cases 15-E-0751 *et al.*, *In the Matter of the Value of Distributed Energy Resources* ("VDER Proceeding"), Revised VDER Value Stack and Rate Design Working Group Process and 2018 Schedule (filed December 22, 2017) ("Staff Process Document"). Deadlines were subsequently extended via a letter from Staff in the same proceeding filed on April 6, 2018 and then further extended in a letter from Staff filed on May 18, 2018 which established May 29, 2018 as the new filing deadline for rate design proposals.

2 VDER Proceeding, Department of Public Service Staff Guiding Instructions to Utilities and Stakeholders on the Approach/Implementation of Mass Market Rate Reform and Bill Impact Analysis (filed January 30, 2018) ("Guiding Instructions").

("O&R"), and Rochester Gas and Electric Corporation ("RG&E") (collectively, the "Joint Utilities" or the "Utilities") submit the following rate design proposals for Staff consideration.

I. Introduction

The Joint Utilities have long supported the continued development of clean energy and distributed energy resources ("DER") in New York. Issues surrounding rate design for DER customers are nearly as old as DER technologies themselves, with NEM providing the primary basis for rooftop solar compensation since the 1990s. Since that time, understanding and appreciation for the potential size and scope of the DER market in New York has grown significantly. The Utilities have welcomed the expansion and diversification of the DER market as a wider array of clean energy technologies including energy storage, beneficial electrification measures such as heat pumps and electric vehicles, and other technologies becomes available to customers. All of these resources will play a key role in meeting New York's ambitious clean energy, Reforming the Energy Vision ("REV"),[3] and greenhouse gas emissions reduction goals, and will play a growing role in meeting customer heating, cooling, and transportation needs.

In recognition of this growth and change, the Joint Utilities support the efforts of the New York Public Service Commission (the "Commission") and Staff to reform rate designs and, specifically, their effort to develop a NEM successor tariff for mass market customers to support the next phase of DER market development. Increasingly, today's delivery rate designs for mass market customers, which are mainly volumetric in nature, create challenges to the efficient development of the residential and small commercial DER market in New York because current rates recover embedded costs inequitably and therefore send improper price signals. These

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[3] Case 14-M-0101, *Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision* ("REV" or "REV Proceeding").

challenges stem from the fundamental design of the rates themselves. The existing volumetric rates are used to recover the costs associated with an electric grid that is designed, built, and maintained to reliably serve customers based on demands at the customer, local, upstream, and bulk power system levels. This means that demands (measured in kilowatts or "kW") at these various levels form the basis for system design criteria, construction, and maintenance. Once the system is built and maintained to serve a given level of demand, any volume of energy (measured in kilowatt-hours or "kWh") up to that kW design level can flow through the system without having a material impact or creating new costs.

Today's mass market delivery rate structures continue to recover costs based on volumetric charges. Because the current volumetric delivery rate design for mass market customers is not aligned with demand-based utility costs, utility customers and DER developers receive improper price signals that drive suboptimal investment and energy usage decisions. This leads to higher overall costs for customers and economic inefficiency. Today, mass market customers who adopt technologies to reduce their overall volumetric energy usage (kWh) but do not change their overall peak demand receive lower delivery bills even though they may impose the same cost on the system as they did previously. Conversely, mass market customers who adopt technologies to reduce their peak demand but use more energy will see higher delivery bills than they did previously. This mismatch between rates and system design creates a disparity between the costs users impose on the system, and their resulting contribution to maintaining the system. The misalignment results in an inequitable distribution of costs among customers. Further, the bill impact associated with these price signals understandably confuses customer decision-making and contributes to inefficient DER investment.

This underlying mismatch between how utilities' costs are incurred and how they are recovered is at the root of the NEM compensation challenge. In its *Order on Net Energy Metering Transition, Phase One of the Value of Distributed Energy Resources, and Related Matters* ("VDER Phase One Order"),[4] the Commission described this issue, writing that "especially when coupled with volumetric rate structures, NEM does not provide sufficient information to serve as a basis of efficient investment decisions …. For most customers compensated under NEM, compensation … has little or no relationship to the actual values provided to or costs imposed on the system."[5] The VDER Phase One Order finds that existing NEM may lead to the installation of DER that creates lower benefits or higher costs for the electric grid than would otherwise be efficient. The Commission notes that "all utility customers, and in particular non-participants, suffer the impacts of those greater costs and lower benefits"[6] and ultimately found that "the continuation of NEM is inconsistent with REV, Commission policy, and the public interest."[7] The Joint Utilities concur with this finding.

II. Demand-based Delivery Rates Are Critical to Achieving the State's Policy Objectives

As the Joint Utilities have noted throughout the VDER Proceeding working group processes, efforts to implement the changes "necessary to drive achievement of New York's aggressive clean energy goals while also creating the grid of the future envisioned by REV"[8] should be undertaken without delay. A continuation of volumetric delivery rates falls short of

4 VDER Proceeding, Order on Net Energy Metering Transition, Phase One of Value of Distributed Energy Resources, and Related Matters (issued March 9, 2017) ("VDER Phase One Order").
5 *Id.*, p. 21.
6 *Id.*
7 *Id.*, p. 23.
8 *Id.*, p. 27.

the "pressing need to transition away from NEM"[9] highlighted in the VDER Phase One Order and would perpetuate the inaccurate price signals that impede the efficient and cost-effective development of DER in New York.

The Joint Utilities urge Staff, and ultimately the Commission, to adopt demand-based delivery rate structures for mass market customers installing DER in the future. These rate structures appropriately align with the rate design principles adopted by the Commission and, in particular, strike an important balance among the principles of cost causation, customer orientation, and economic sustainability. Because a demand-based rate structure more accurately reflects utility cost causation, it will deliver efficient price signals to these customers and lead to investment decisions that appropriately reflect grid impacts and support REV goals. In the long run, these better-informed decisions will reward customers for investments and behaviors that support the grid, reduce burdens on the electric system, increase grid benefits, and lower costs for all customers compared to what would otherwise occur if current rate designs were left unchanged.

III. Demand-based Delivery Rates Work for Residential and Small-Commercial Customers

Demand-based delivery rates for mass market customers have been successfully implemented across the country and are currently being offered by more than 43 utilities in 22 states.[10] Utilities in Massachusetts, Wyoming, and Arizona have recently instituted mandatory

[9] *Id.*, p. 45.

[10] *See* Matter 17-01277, *In the Matter of the Value of Distributed Energy Resources Working Group Regarding Rate Design*, Ahmad Faruqui & Sanem Sergici, The Brattle Group, Presentation to VDER Rate Design Working Group: Rate Design for DER Customers in New York, A Way Forward (March 6, 2018)("Brattle Rate Design Presentation"), pp. 53-54.

demand-based rates for residential distributed generation customers.[11] Additionally, multiple rate design pilot programs in other jurisdictions have studied customer acceptance of demand rates, including an ongoing program at Xcel Energy's Public Service Company of Colorado. Initial findings from this pilot with nearly 10,000 participants show that customers on a time-varying demand rate have reduced their coincident peak demands by an average of seven percent.[12] This initial finding demonstrates that customers are able to manage their energy use in response to demand charge price signals. Initial surveys show that 86 percent of participants would characterize their experience with these rates as positive and 78 percent would recommend their current rate option to others.[13]

Demand-based rates offered by Arizona Public Service since the 1980s have produced similar results. Customers on the company's demand rate, in place as of 2015, had flatter overall load profiles, with a 37 percent average load factor, compared with customers on a pure time-of-use ("TOU") rate, who had a 29 percent average load factor. These same customers also exhibited a lower peak demand compared to customers on an energy-only TOU rate and those on a standard inclining block rate. Customers on a demand-based TOU rate exhibited peak demand usage 11 to 21 percent lower than customers on the utility's inclining block rate, and 5 to 15 percent lower than customers on an energy-only TOU rate.[14]

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11 *Id*., p. 17. *See, e.g.*, Docket D.P.U. 17-05, Petition of NSTAR Electric Company and Western Massachusetts Electric Company, each doing business as Eversource Energy, Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq., for Approval of General Increases in Base Distribution Rates for Electric Service and Approval of a Performance Based Ratemaking Mechanism, Response of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy to Massachusetts Department of Public Utilities ("D.P.U.") Information Request: DPU-46-14 (dated May 3, 2017) and attachment thereto.

12 Scott Brockett, Xcel Energy, Presentation at the EUCI Residential Demand Charges Conference, Nashville, Tennessee: Update on Public Service Company Residential Demand Charges (May 16, 2018).

13 *Id*.

14 Leland Snook & Meghan Grabel, Arizona Public Service Company, *There and Back Again; Why a Residential Demand Rate Developed 40 Years Ago is Increasingly Relevant Today*, Public Utilities Fortnightly (November 2015).

These and other results from across the country present a growing body of evidence that demonstrates the viability of demand rates for mass market customers, and indeed the ability of customers to respond by managing their usage, lowering their utility bills, and reducing overall system costs. Experience across the country shows that demand-based delivery rates can be understood by customers and help to promote economically-efficient consumption and investment decisions.

IV. Customer Outreach and Education Is a Key Component to Successful Implementation of Demand-Based Rates

The Joint Utilities are committed to developing robust customer outreach and education programs should demand-based delivery rates be implemented as the successor to NEM. The Utilities recognize that this rate structure will be a new concept for New York customers and recommend that focused outreach and education materials be developed and provided to customers prior to transitioning to the new rate structure. Simple messages, such as reminding customers not to use multiple, large appliances all at once, have proven effective in other states.[15] Ongoing communications could support customers during their first year on these new rates, reminding customers of strategies to manage their demand and electricity bills.

An initial focus of developing these campaigns will be language strategies – identifying the terminology, messages, and educational approaches that resonate with customers. The Utilities would plan to use a combination of customer focus groups and surveys to test various outreach and education approaches, including naming conventions for these new rates. As such, the naming conventions used in this filing (*i.e.*, "2 Demand Rate" and "TOU Demand Rate") are

15 Brattle Rate Design Presentation, pp. 32-34, 38, 45-46.

intended for use among policy stakeholders in this proceeding only and would likely not be used in broader communications with customers.

Additional strategies, such as limited bill protection for a period of time, could be implemented to further support and educate customers about this new rate structure. Care could also be taken to proactively monitor impacts on customers participating in the Utilities' low-income customer programs. These and other details of customer-facing outreach could be determined at a later time should Staff and the Commission decide to move forward with a demand-based rate structure.

V. Summary of the Joint Utilities' 2 Demand Rate and TOU Demand Rate Design Proposals

A. Introduction

The Joint Utilities submit two rate design proposals in this filing, which are provided in both Excel and PDF formats with the PDF version appended as Attachments B through E (2 Demand Rate Design proposal) and F through I (TOU Demand Rate Design proposal). In the sections that follow, the Joint Utilities describe the proposals in detail, including supporting explanations and rationales. The Joint Utilities' two rate design proposals, referred to as the "2 Demand Rate" and the "TOU Demand Rate" proposals, reflect and advance REV rate design objectives as discussed in the Guiding Instructions.[16] The Joint Utilities' proposals also build on Commission directives, including those from its *Order Adopting a Ratemaking and Utility Revenue Model Policy Framework* in the REV Proceeding.[17]

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[16] VDER Proceeding, Guiding Instructions, pp. 1-3.

[17] REV Proceeding, Order Adopting a Ratemaking and Utility Revenue Model Policy Framework (issued May 19, 2016) ("REV Track Two Order").

Attachment A
Overview

The two rate design proposals are similar in both purpose and in structure. As described above, the overall purpose of these proposed rate designs is to significantly improve the equitability of cost recovery and thus the accuracy and clarity of the price signals to new DER customers, which will allow these customers to make more economically efficient decisions regarding DER investment and energy usage. These rate design proposals would encourage outcomes through price signals that allow customers opportunities to manage demand while supporting REV goals. In addition, these rate design proposals improve economic efficiency by using the proposed demand charges to signal to new DER customers the value of actions they can take to reduce the demand that drives system costs. The Joint Utilities' rate design proposals are especially focused on economic efficiency. In both proposals, the demand charges account for differences in (a) local distribution costs that are largely driven by customer maximum demands and (b) upstream delivery costs that are driven by the temporal coincidence of those demands with system peaks.

Both proposals recover delivery costs through demand (kW) charges and a monthly customer charge (a fixed amount each billing period), and supply costs through volumetric (kWh) charges. In both proposals, the demand charges replace volumetric delivery charges, which currently recover demand-related costs for delivery. The demand charges are calculated to recover the same level of costs as are currently recovered through the volumetric charges of the applicable rate class and are therefore designed to be revenue-neutral.[18]

The proposed demand charges for both proposals reflect temporal and seasonal cost differences. Further, both proposals determine demand charges in a manner that accounts for

[18] Equivalently, the proposed demand charges are calculated to recover: (a) the portion of the rate class customer-related costs that are not recovered in the current (and proposed) customer charges; (b) secondary distribution costs; (c) primary distribution costs, and (d) transmission costs, as those costs are all determined in each utility's current embedded cost of service ("ECOS") study.

differences in the cost drivers for local facilities which are located in close proximity to customers' homes or businesses versus upstream facilities which are located (electrically) further from the customer.[19] Upstream delivery costs and local distribution costs for both proposals are utility-specific and based on each utility's ECOS study.

For both proposals, each of the Utilities will determine the months of the proposed seasons and hours of the proposed TOU periods based on their utility-specific data and analysis. Most of the Joint Utilities are "summer peaking" utilities; the rate design proposals for these utilities are structured to reflect that coincident peak ("CP") demand in the summer period is the cost driver for the utility's upstream delivery costs.[20] In both rate design proposals, each utility uses the same seasons and peak periods for delivery and supply charges.

In both of the rate design proposals, supply costs associated with commodity and installed capacity ("ICAP") are recovered through volumetric (kWh) charges that vary by TOU (peak and off-peak) and by season.[21] Various adjustment charges and other supply components, including ancillary service costs, New York Power Authority transmission adjustment charges, renewable energy credits, zero-emission credits, and a true-up component will continue to be charged volumetrically in both rate design proposals.

Finally, both approaches maintain fixed customer charges at current levels for each utility (*i.e.*, levels approved as of April 1, 2018). As a result, the proposed customer charges do not recover all customer-related costs, as demonstrated by the Joint Utilities' March 6, 2018 presentation to the VDER Working Group Regarding Rate Design. That presentation showed

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[19] As explained in Sections V.B and V.C herein, the 2 Demand Rate and TOU Demand Rate proposals differ in the way that the local distribution and upstream delivery costs are reflected in the design of the proposed delivery demand charges.

[20] NYSEG has determined that its CP demand could occur in the summer or the winter. As a result, NYSEG's rate proposals are structured with summer and winter periods.

[21] As explained in Sections V.B and V.C herein, the 2 Demand Rate and TOU Demand Rate proposals differ in the way that supply and ICAP costs are recovered by season and by TOU period.

that the current customer charges for each utility are less than total customer-related costs identified in each utility's ECOS study.

While the Joint Utilities' two rate design proposals are substantially alike, as described above, there are certain differences. The following sections outline specific aspects of the 2 Demand Rate and TOU Demand Rate design proposals.

B. 2 Demand Rate Design Proposal

The 2 Demand Rate proposal includes two separate measures of customer demand: (a) the customer's non-coincident peak ("NCP") demand, which is the customer's maximum demand during each billing period, and (b) the customer's CP demand, which is a customer's maximum demand during the system's peak period hours of each summer billing period (or, more generally, "high demand" billing period) as determined by each utility based on an assessment of its system. Peak periods will likely need to be updated and maintained via a regular, orderly process to ensure that they reflect current system conditions.

The NCP demand charge reflects a customer's contribution to costs associated with local facilities. The NCP demand charge recovers local distribution costs, which are generally: (a) the portion of the rate class customer-related costs that is not recovered in the current (and proposed) customer charge, (b) secondary distribution demand-related costs, and (c) a portion of primary distribution costs. The portion of primary distribution costs included in local distribution costs will be determined on a utility-specific basis. NCP demand charge billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification for each of the 12 months. The NCP demand charge is identical across all 12 months in a year. A customer's NCP billing demand charge will be calculated as the average of the customer's three highest daily demands occurring during each billing period.

The CP demand charge is designed to align price signals received by customers with their responsibility for those costs related to serving the utility's system peak load. The CP demand charge recovers upstream delivery costs, which are generally: (a) a portion of primary distribution-related costs not included in local distribution costs, and (b) transmission costs. The billing determinants used to calculate the CP demand charge are the sum of the CP billing demands of all customers in each mass market rate classification. A customer's CP billing demand will be calculated as the average of a customer's three highest daily demands in the peak period for each of the summer[22] billing periods. Each utility will set peak periods based on utility-specific data.

Supply costs under the 2 Demand Rate proposal will be recovered through volumetric peak and off-peak (kWh) charges that vary on a monthly basis. The peak rate in the summer months will recover annual ICAP costs. During the non-summer months,[23] the peak and off-peak supply rates are equal.

C. TOU Demand Rate Design Proposal

The TOU Demand Rate proposal also includes two measures of demand in each billing period of the year: (1) a customer's maximum demand during the peak period, and (2) a customer's maximum demand during the off-peak period.

The peak demand charges are designed to recover a portion of the rate class local distribution costs and upstream delivery costs. The peak demand charge will vary by season in a manner specific to each utility. The off-peak demand charges are designed to recover a portion of the local distribution costs. Local distribution costs include: (a) customer-related costs that

[22] Or high demand season, if applicable.
[23] Or non-high demand season, if applicable.

are not recovered in the current (and proposed) customer charge, (b) secondary distribution costs, and (c) a portion of primary distribution costs, which will be determined on a utility-specific basis. Upstream delivery costs include: (a) the portion of primary distribution costs that are not local distribution costs, and (b) transmission costs.

The billing determinants used to calculate the peak and off-peak demand charges, by season, are the sums of customers' seasonal peak period and off-peak period billing demands, respectively. A customer's peak and off-peak billing demands will be calculated as the average of the customer's three highest daily peak demands and the average of the three highest daily off-peak period demands, respectively, occurring during a billing period.

The TOU Demand Rate proposal may be described as consisting of a "base" demand rate layer that is included in both the peak and off-peak demand charges for all seasons, and an "incremental" demand rate layer on top of the base rate during peak periods of each season. The base demand rate layer is designed to recover local distribution costs and the incremental rate layer is designed to recover upstream delivery costs. The off-peak period demand charge is the same as the base demand rate layer and the peak period demand charge is the sum of the incremental demand rate layer and the base demand rate layer.

Supply costs under the TOU Demand Rate proposal will be recovered through volumetric peak and off-peak (kWh) charges that vary on a monthly basis. The peak period supply rates recover peak energy costs and ICAP costs. The off-peak period supply rates will recover off-peak energy costs.

D. Summary

The similarities in the structure of the demand charges for the 2 Demand Rate and the TOU Demand Rate proposals, as shown in Figure 1, below, are:

- Both proposals recover local distribution costs based on customer demand (a) in all billing periods of the year, and (b) in all hours of the day;
- Both proposals recover upstream delivery costs based on customer demand in peak period hours;
- Both proposals measure billing demand as the average of a customer's top three daily maximum demands in the billing period; and
- Under both proposals, demand is measured over a 60-minute interval.

The differences in the structure of the demand charges for the 2 Demand Rate and TOU Demand Rate proposals, as shown in Figure 1, below, are:

- The 2 Demand Rate proposal will recover upstream delivery costs in the summer (or high demand) periods only, whereas the TOU Demand Rate proposal will recover upstream delivery costs in all seasons.
- In the 2 Demand Rate proposal, customers' demands in the peak period can set the demand rate for both the CP and the NCP rate, whereas in the TOU Demand Rate proposal, only demands outside the peak period determine the off-peak period demand charges.

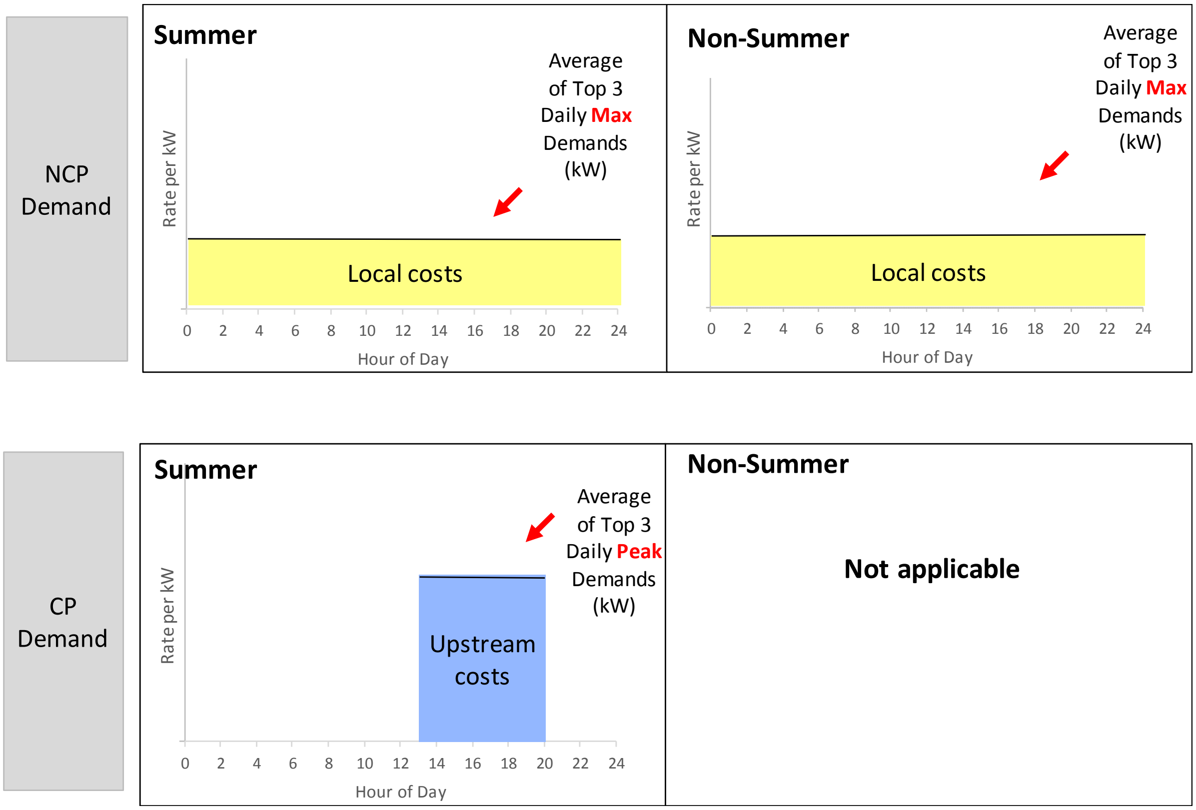
Each of the utilities used system data to determine company-specific TOU periods and seasons. The TOU periods and seasons are not the same for each utility because the system data reflect differences in the number and mix of each utility's customers and the energy use characteristics of these customers.[24]

With respect to supply, the 2 Demand Rate proposal recovers ICAP costs during peak periods solely in the summer months, while the TOU Demand Rate proposal recovers these costs during peak periods in all months of the year.

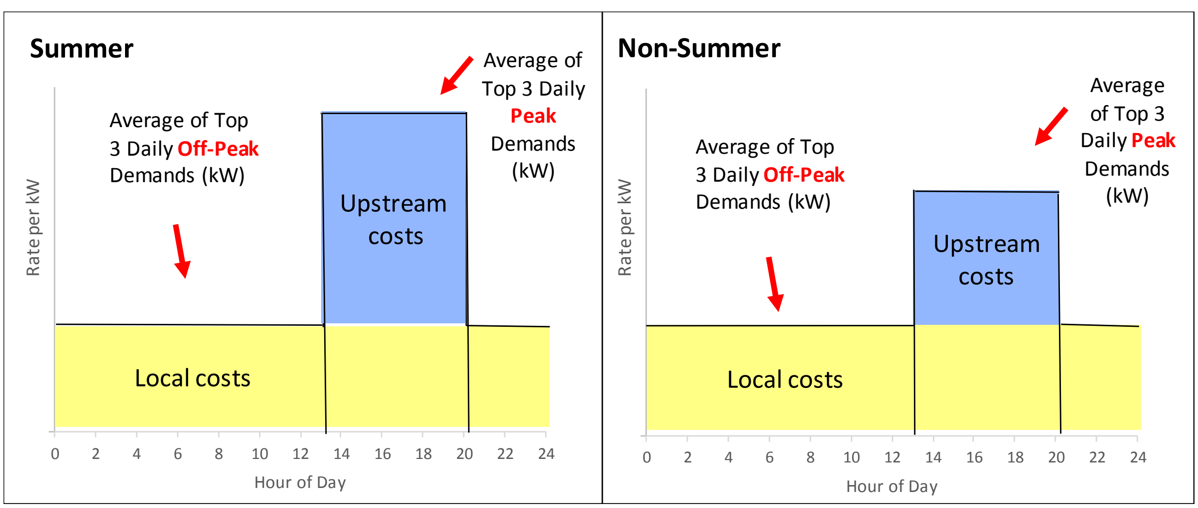
[24] Further, although RG&E, Con Edison, O&R, National Grid, and Central Hudson determined that their high demand season occurs during the summer months, NYSEG's high demand season includes both summer and winter months. NYSEG has identified a third "shoulder" season comprised of all months that are not included in the summer or winter seasons.

Attachment A
Overview

Figure 1: Structure of Proposed Demand Charges for Delivery



Demand Charge Structure: 2 Demand Rate Proposal



Demand Charge Structure: TOU Demand Rate Proposal

VI. Conclusion

As described herein, the Joint Utilities' rate design proposals – 2 Demand Rate and TOU Demand Rate – include critically important features that are vital to achieving REV goals. The Joint Utilities strongly recommend that both proposals be selected by Staff for further analysis and consideration. The Joint Utilities look forward to working with Staff and other stakeholders in conducting the requested analysis of these and/or other proposals selected by Staff in order to advance this important process of identifying mass market NEM successor rates.

Dated: May 29, 2018

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. and ORANGE AND ROCKLAND UTILITIES, INC.
By: */s/ Susan J. Vercheak*

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ATTACHMENTS B-E

2 DEMAND RATE DESIGN PROPOSAL

1. Stakeholder(s) Identification

Color Code

Stakeholder input - enter value or text

a.	Stakeholder/Collaboration Name:	The Joint Utilities
b.	List of Organization(s)	
	1	Niagara Mohawk Power Company d/b/a/ National Grid
	2	Consolidated Edison Company of New York, Inc.
	3	Orange and Rockland Utilities, Inc.
	4	New York State Electric & Gas Corporation
	5	Rochester Gas and Electric Corporation
	6	Central Hudson Gas & Electric Corporation
c.	Stakeholder Contact Name(s)	
	1	Lauri Mancinelli
	2	William Atzl
	3	William Atzl
	4	Patti Beaudoin
	5	Patti Beaudoin
	6	Glynis Bunt
d.	Email Address(es) for Contact(s)	
	1	Lauri.Mancinelli@nationalgrid.com
	2	AtzlW@coned.com
	3	AtzlW@coned.com
	4	pabeaudoin@nyseg.com
	5	pabeaudoin@nyseg.com
	6	Gbunt@cenhud.com
e.	Phone Number(s) for Contact(s)	
	1	781-907-3809
	2	212- 460-3308
	3	212- 460-3308
	4	607-762-7061
	5	607-762-7061
	6	845-486-5420
f.	Proposal Name	JU_2 Demand

2. Information fields to be entered by Stakeholder(s) for each Rate Design Proposal

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

a. Stakeholder and Proposal Name

Stakeholder/Collaboration Name:	The Joint Utilities
Proposal Name	JU_2 Demand

b. Applicable Mass Market Service Class(es)

Current Mass Market service classes(es) for which this proposed rate design would apply.

Residential and Small Commercial Non-Demand

c. Is this rate design proposal for delivery or supply rates?

Delivery and Supply

d. Please select delivery rate design parameters to be included in proposals

Delivery Rate Design Parameters	Will the Rate Design Include each of the following? (Provide Yes / No responses from the drop down menu)
Customer Charge	Yes
Per kWh Rate	No
Demand Measure 1 Rate	Yes
Demand Measure 2 Rate	Yes
Seasonal	Yes
TOU	Yes
CPP	No
Other Delivery	

The Applicable Delivery Rate Design Parameter Input Section: Based on the responses provided above to the yes/no questions on Delivery rate design parameters, the cell below will indicate the area in Tab 3, Delivery with the input details for the indicated Delivery Rate Design Parameters.

3.p. Seasonal 4 Part TOU

e. Please select supply rate design parameters to be included in proposals

Supply Rate Design	Monthly Peak, Off Peak Supply pricing
The Applicable Supply Rate Design Parameter Input Section: Based on the responses provided above to the Supply rate design parameter, the cell below will indicate the area in Tab 4, Supply, with the input details for the indicated Supply Rate Design Parameters.	
	4.b. Monthly Peak, Off Peak Supply pricing

f. Overall Rate Design objective: In one or two sentences, describe the rate design proposal and the expected effect of the proposed rate design on new DER customers. [Limit to 2000 Characters]

The proposed delivery rate design includes: a fixed customer charge, and non-coincident peak (NCP) and coincident peak (CP) demand charges. Initially, the proposed customer charge is set at the current (as of 4/1/18) approved customer charge. The proposed CP and NCP charges are calculated to recover the level of delivery revenues that is currently recovered through kWh charges. See 2.i for additional detail.

The seasons and peak and off-peak periods are determined by each utility, based on utility-specific data and analysis. The “high demand” season consists of certain months in the summer, for all utilities except NYSEG, and certain months in the summer and winter for NYSEG. For all utilities, the high demand peak period is the same for delivery and supply charges.

CP billing demand is defined as the average of a customer’s three highest daily peak period demands occurring during each billing period of the high demand season. NCP billing demand is defined as the average of a customer’s three highest daily demands in each billing period.

Supply costs will be recovered through volumetric charges that vary on a monthly basis. Annual capacity (ICAP) costs will be recovered on a per kWh basis and applied to the supply charges during the peak period and only in the summer months. During non-summer months (or non-high demand season, if applicable), the volumetric peak and off-peak supply rates are equal.

The proposed rate design will significantly improve the accuracy and clarity of price signals, which will allow customers to make more economically efficient decisions regarding DER investment and energy usage. The benefits of DER investments to a new DER customer will be reflected in cost-based supply rates that appropriately vary by peak and off-peak period and season and delivery rates that appropriately reflect CP and NCP cost drivers.

g. Referring to the Rate Design Principles that were adopted by the Commission in the Track Two Order, please (i) indicate the Rate Design Principles that the Stakeholder considers to be most important and (ii) how the Rate Design Proposal addresses the indicated principles. [Limit to 2000 Characters]

This proposal considers all Rate Design Principles but strikes a reasoned balance among the principles deemed most important by the JU: cost causation, customer orientation, and economic sustainability.

This proposal marks a critical step forward in the application of the principle of cost causation, which is a vital component of REV rate design, to mass market rates. Because utility systems are built to serve demands at the customer, local, upstream and bulk power system levels, the delivery-related costs are based on customers' demands; the proposed delivery CP and NCP demand charges reflect this relationship between customer demands and utility costs. In contrast, the current mass market volumetric rate structures provide inefficient price signals that do not reflect that utility distribution costs are driven by customer demand. The proposed peak and off-peak supply energy (per kWh) charges reflect that supply costs are driven by the time of use.

Customers considering DERs will be able to make informed decisions on investments in DER; energy-consuming and energy-conserving equipment; and behavioral changes because the proposed delivery demand charges and the supply charges provide more efficient price signals. Thus, this rate design proposal is a significant step towards a long-term vision of price signals for traditional and prosumer mass market customers that will be economically sustainable.

This proposal is customer-oriented: the growing body of experience with mass market demand rates in the US demonstrates that - with the JU-provided customer education – the rate design proposal is understandable to mass market customers and will promote economically efficient consumption and investment decisions.

h. Rate Design Qualitative Benefits: Provide any additional benefits of the proposed rates that may not have been included in the rate design criteria. [Limit to 2000 Characters]

The price signals that are inherent in this proposal encourage support for REV objectives while also allowing customers to manage energy use. This rate design improves the price signals to mass market customers provided by delivery rates not only by introducing kW demand charges to recover demand-related delivery costs, but also by providing separate price signals for local distribution costs, which are associated with the NCP demand charge, and upstream delivery costs, which are associated with the CP demand charge.

Because current volumetric rate design for mass market customers is not aligned with demand-driven utility costs, customers and DER developers today receive improper price signals that drive decisions and investments that are not beneficial to the general body of electric utility customers and the electric grid as a whole. These price signals, which are misaligned with utility costs, confuse customer decision-making and result in inefficient DER investments.

This proposal addresses concerns articulated by the Commission in its March 9, 2017 Order on net energy metering (NEM) (“Order”), which states “especially when coupled with volumetric rate structures, NEM does not provide sufficient information to serve as a basis of efficient investment decisions …. For most customers compensated under NEM, compensation … has little or no relationship to the actual values provided to or costs imposed on the system.” (Order, p. 21). The Order finds that this may lead to the installation of DERs that creates lower benefits or higher costs for the electric grid than would otherwise be efficient. The Commission states that “all utility customers, and in particular non-participants, suffer the impacts of those greater costs and lower benefits.” (Id.) This proposal addresses this concern by sending correct price signals, which will advance REV goals and benefit customers and the grid.

i.	Additional information or guidance: Provide any additional information or guidance to support selecting and prioritizing the rate design proposal or in supporting the rate design and bill impact analysis. [Limit to 2000 Characters]
	To further explain the JU's 2 Demand delivery rate design proposal, which is provided in the Input Workbook, Tab 2.f and Tab 3.p, the NCP demand charge is designed to recover local distribution costs, which are generally: (a) the portion of the rate class customer-related costs that is not recovered in the current (and proposed) customer charge, (b) secondary distribution demand-related costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. The CP demand charge is designed to recover upstream delivery costs, which are, generally, primary distribution-related costs not included in local distribution costs, and transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study. The proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results. The NCP demand charge is applied to a customer's NCP billing demand in each billing period of the year and the CP demand rate is applied to the CP billing demand during the months of the high demand season. RG&E, Con Ed, O&R, Grid, and CH determined that their high demand season occurs in certain summer months, NYSEG determined that its high demand season occurs in certain summer and winter months. NYSEG has identified a shoulder season comprised of all months not included in the summer or winter seasons. The NCP demand charge billing determinants are the sum of NCP billing demands for all 12 months. The CP demand charge billing determinants are the sum of the CP class billing demands for each of the high demand months. CP billing demand is the average of a customer's three highest daily demands that occur during the peak period of each billing period of the high demand season; NCP demand is the average of a customer's three highest daily demands that occur during all hours each billing period.

3. Delivery Rate Structures

Central Hudson Gas & Electric Corporation - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

p. Seasonal 4 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		Calculation of per kWh Charges is not applicable to JU's rate design proposal.
Demand Charges	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
NCP demand charge (Demand 1 charge)	N/A		The NCP (Demand 1) charge is to be applied to a customer's NCP billing demand (as defined below) in each billing period. As further described below, NCP billing demand is measured during all hours of the day, all days of the week; TOU periods do not apply to the measurement of NCP demand. The NCP (Demand 1) charge for both residential and small commercial non-demand (i.e., "mass market") rate classifications is to be calculated by dividing (a) the rate class local distribution costs by (b) NCP billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution demand-related costs; and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. NCP billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification (the measurement of NCP billing demands is defined below).
CP demand charge (Demand 2 Charge)	N/A		The CP (Demand 2) charge is to be applied to a customer's CP billing demand (as defined below) in each summer billing period. As further described below, CP billing demand is measured during peak period hours only. The CP (Demand 2) charge for both mass market rate classifications is to be calculated by dividing (a) upstream delivery costs by (b) CP billing determinants. Upstream delivery costs include (a) the portion of primary distribution-related costs not included in local distribution costs and (b) transmission costs. CP billing determinants are the sum of the CP billing demands for all customers in each mass market rate classification (the measurement of CP billing demands is defined below). Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Per kWh Charges	0%		Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

3. Delivery Rate Structures

Central Hudson Gas & Electric Corporation - 2 Demand Rate Approach

NCP Demand Charge (Demand 1 Charge) - to shape summer / non-summer NCP Demand Charge (Demand 1 Charge) rates			
Summer Peak: Non-Summer Peak	1	: 1	Neither seasons nor TOU periods are applicable to the NCP Demand charge.
NCP Demand Charge (Demand 1 Charge) - to shape peak / off peak NCP Demand Charge (Demand 1 Charge) rates			
Peak: Off Peak, Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
Peak: Off Peak, Non-Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
CP Demand Charge (Demand 2 Charge) - to shape summer / non-summer CP Demand Charge (Demand 2 Charge) rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not Applicable: The CP (Demand 2) charge applies only in the summer, peak period.
CP Demand Charge (Demand 2 Charge) - to shape peak / off peak CP Demand Charge (Demand 2 Charge) rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.

NCP Demand Charge (Demand 1 Charge)		Input direction/guidance for rate component
Demand Measure	Customer max demand during all hours in the month	NCP demand will be measured as a customer's maximum demand during all hours of each day of the billing period.
Demand Calculation	Avg top 3 days customer max demand in billing month	NCP billing demand will be calculated as the average of a customer's three highest daily demands in each billing period.
Demand Metering Interval	60 minutes	Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
CP Demand Charge (Demand 2 Charge)		
Demand Measure	Customer max demand during peak hours in the month	CP demand will be measured as a customer's maximum demand during peak period hours during each billing period of the summer.
Demand Calculation	Avg top 3 days customer max demand in billing month	CP billing demand will be calculated as the average of a customer's three highest daily CP demands occurring during each billing period of the summer.
Demand Metering Interval	60 minutes	Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.

Peak Period Definition	
Peak period includes:	All non-holiday weekdays

Duration of TOU periods

Summer Months	Hours/day	
Peak	5	For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. The on-peak period applies only to the summer CP (Demand 2) charge. On-peak hours are only during non-holiday weekdays.
Off Peak	19	During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/day	
Peak	N/A	For this proposal, peak/off-peak periods are not applicable in non-summer months for delivery demand charges.
Off Peak	N/A	

3. Delivery Rate Structures

Consolidated Edison Company of New York - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

p. Seasonal 4 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		Calculation of per kWh Charges is not applicable to JU's rate design proposal.
Demand Charges	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		

Of remaining class revenue requirement, what percentage should be recovered through:			
NCP demand charge (Demand 1 charge)	N/A		The NCP (Demand 1) charge is to be applied to a customer's NCP billing demand (as defined below) in each billing period. As further described below, NCP billing demand is measured during all hours of the day, all days of the week; TOU periods do not apply to the measurement of NCP demand. The NCP (Demand 1) charge for both residential and small commercial non-demand (i.e., "mass market") rate classifications is to be calculated by dividing (a) the rate class local distribution costs by (b) NCP billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution demand-related costs; and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. NCP billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification (the measurement of NCP billing demands is defined below).
CP demand charge (Demand 2 Charge)	N/A		The CP (Demand 2) charge is to be applied to a customer's CP billing demand (as defined below) in each summer billing period. As further described below, CP billing demand is measured during peak period hours only. The CP (Demand 2) charge for both mass market rate classifications is to be calculated by dividing (a) upstream delivery costs by (b) CP billing determinants. Upstream delivery costs include (a) the portion of primary distribution-related costs not included in local distribution costs and (b) transmission costs. CP billing determinants are the sum of the CP billing demands for all customers in each mass market rate classification (the measurement of CP billing demands is defined below). Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Per kWh Charges	0%		Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

3. Delivery Rate Structures

Consolidated Edison Company of New York - 2 Demand Rate Approach			
NCP Demand Charge (Demand 1 Charge) - to shape summer / non-summer NCP Demand Charge (Demand 1 Charge) rates			
Summer Peak: Non-Summer Peak	1	: 1	Neither seasons nor TOU periods are applicable to the NCP Demand charge.
NCP Demand Charge (Demand 1 Charge) - to shape peak / off peak NCP Demand Charge (Demand 1 Charge) rates			
Peak: Off Peak, Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
Peak: Off Peak, Non-Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
CP Demand Charge (Demand 2 Charge) - to shape summer / non-summer CP Demand Charge (Demand 2 Charge) rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not Applicable: The CP (Demand 2) charge applies only in the summer, peak period.
CP Demand Charge (Demand 2 Charge) - to shape peak / off peak CP Demand Charge (Demand 2 Charge) rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
NCP Demand Charge (Demand 1 Charge)			Input direction/guidance for rate component
Demand Measure	Customer max demand during all hours in the month		NCP demand will be measured as a customer's maximum demand during all hours of each day of the billing period.
Demand Calculation	Avg top 3 days customer max demand in billing month		NCP billing demand will be calculated as the average of a customer's three highest daily demands in each billing period.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
CP Demand Charge (Demand 2 Charge)			
Demand Measure	Customer max demand during peak hours in the month		CP demand will be measured as a customer's maximum demand during peak period hours during each billing period of the summer.
Demand Calculation	Avg top 3 days customer max demand in billing month		CP billing demand will be calculated as the average of a customer's three highest daily CP demands occurring during each billing period of the summer.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer Months	Hours/day		
Peak	8		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. The on-peak period applies only to the summer CP (Demand 2) charge. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/day		
Peak	N/A		For this proposal, peak/off-peak periods are not applicable in non-summer months for delivery demand charges.
Off Peak	N/A		

3. Delivery Rate Structures

National Grid - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

p. Seasonal 4 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		Calculation of per kWh Charges is not applicable to JU's rate design proposal.
Demand Charges	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		

Of remaining class revenue requirement, what percentage should be recovered through			
NCP demand charge (Demand 1 charge)	N/A		The NCP (Demand 1) charge is to be applied to a customer's NCP billing demand (as defined below) in each billing period. As further described below, NCP billing demand is measured during all hours of the day, all days of the week; TOU periods do not apply to the measurement of NCP demand. The NCP (Demand 1) charge for both residential and small commercial non-demand (i.e., "mass market") rate classifications is to be calculated by dividing (a) the rate class local distribution costs by (b) NCP billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution demand-related costs; and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. NCP billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification (the measurement of NCP billing demands is defined below).
CP demand charge (Demand 2 Charge)	N/A		The CP (Demand 2) charge is to be applied to a customer's CP billing demand (as defined below) in each summer billing period. As further described below, CP billing demand is measured during peak period hours only. The CP (Demand 2) charge for both mass market rate classifications is to be calculated by dividing (a) upstream delivery costs by (b) CP billing determinants. Upstream delivery costs include (a) the portion of primary distribution-related costs not included in local distribution costs and (b) transmission costs. CP billing determinants are the sum of the CP billing demands for all customers in each mass market rate classification (the measurement of CP billing demands is defined below). Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Per kWh Charges	0%		Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

3. Delivery Rate Structures

National Grid - 2 Demand Rate Approach

NCP Demand Charge (Demand 1 Charge) - to shape summer / non-summer NCP Demand Charge (Demand 1 Charge) rates			
Summer Peak: Non-Summer Peak	1	: 1	Neither seasons nor TOU periods are applicable to the NCP Demand charge.
NCP Demand Charge (Demand 1 Charge) - to shape peak / off peak NCP Demand Charge (Demand 1 Charge) rates			
Peak: Off Peak, Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
Peak: Off Peak, Non-Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
CP Demand Charge (Demand 2 Charge) - to shape summer / non-summer CP Demand Charge (Demand 2 Charge) rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not Applicable: The CP (Demand 2) charge applies only in the summer, peak period.
CP Demand Charge (Demand 2 Charge) - to shape peak / off peak CP Demand Charge (Demand 2 Charge) rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
NCP Demand Charge (Demand 1 Charge)			Input direction/guidance for rate component
Demand Measure	Customer max demand during all hours in the month		NCP demand will be measured as a customer's maximum demand during all hours of each day of the billing period.
Demand Calculation	Avg top 3 days customer max demand in billing month		NCP billing demand will be calculated as the average of a customer's three highest daily demands in each billing period.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
CP Demand Charge (Demand 2 Charge)			
Demand Measure	Customer max demand during peak hours in the month		CP demand will be measured as a customer's maximum demand during peak period hours during each billing period of the summer.
Demand Calculation	Avg top 3 days customer max demand in billing month		CP billing demand will be calculated as the average of a customer's three highest daily CP demands occurring during each billing period of the summer.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer Months	Hours/day		
Peak	5		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. The on-peak period applies only to the summer CP (Demand 2) charge. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/day		
Peak	N/A		For this proposal, peak/off-peak periods are not applicable in non-summer months for delivery demand charges.
Off Peak	N/A		

3. Delivery Rate Structures

New York State Electric & Gas Corporation - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

p. Seasonal 4 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		Calculation of per kWh Charges is not applicable to JU's rate design proposal.
Demand Charges	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		

Of remaining class revenue requirement, what percentage should be recovered through			
NCP demand charge (Demand 1 charge)	N/A		The NCP (Demand 1) charge is to be applied to a customer's NCP billing demand (as defined below) in each billing period. As further described below, NCP billing demand is measured during all hours of the day, all days of the week; TOU periods do not apply to the measurement of NCP demand. The NCP (Demand 1) charge for both residential and small commercial non-demand (i.e., “mass market”) rate classifications is to be calculated by dividing (a) the rate class local distribution costs by (b) NCP billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution demand-related costs; and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. NCP billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification (the measurement of NCP billing demands is defined below).
CP demand charge (Demand 2 Charge)	N/A		The CP (Demand 2) charge is to be applied to a customer's CP billing demand (as defined below) in each summer billing period. As further described below, CP billing demand is measured during peak period hours only. The CP (Demand 2) charge for both mass market rate classifications is to be calculated by dividing (a) upstream delivery costs by (b) CP billing determinants. Upstream delivery costs include (a) the portion of primary distribution-related costs not included in local distribution costs and (b) transmission costs. CP billing determinants are the sum of the CP billing demands for all customers in each mass market rate classification (the measurement of CP billing demands is defined below). Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Per kWh Charges	0%		Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

Please provide the following price ratios:			
Per kWh Charges - to shape Summer/Winter / non-Summer/Winter per kWh rates			
Summer/Winter Peak: Non-Summer/Winter Peak	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer/Winter	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer/Winter	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

3. Delivery Rate Structures

New York State Electric & Gas Corporation - 2 Demand Rate Approach			
NCP Demand Charge (Demand 1 Charge) - to shape Summer/Winter / non-Summer/Winter NCP Demand Charge (Demand 1 Charge) rates			
Summer/Winter Peak: Non-Summer/Winter Peak	1	: 1	Neither seasons nor TOU periods are applicable to the NCP Demand charge.
NCP Demand Charge (Demand 1 Charge) - to shape peak / off peak NCP Demand Charge (Demand 1 Charge) rates			
Peak: Off Peak, Summer/Winter	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
Peak: Off Peak, Non-Summer/Winter	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
CP Demand Charge (Demand 2 Charge) - to shape Summer/Winter / non-Summer/Winter CP Demand Charge (Demand 2 Charge) rates			
Summer/Winter Peak: Non-Summer/Winter Peak	N/A	: 1	Not Applicable: The CP (Demand 2) charge applies only in the summer/winter, peak period.
CP Demand Charge (Demand 2 Charge) - to shape peak / off peak CP Demand Charge (Demand 2 Charge) rates			
Peak: Off Peak, Summer/Winter	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
Peak: Off Peak, Non-Summer/Winter	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
NCP Demand Charge (Demand 1 Charge)			Input direction/guidance for rate component
Demand Measure	Customer max demand during all hours in the month		NCP demand will be measured as a customer’s maximum demand during all hours of each day of the billing period.
Demand Calculation	Avg top 3 days customer max demand in billing month		NCP billing demand will be calculated as the average of a customer’s three highest daily demands in each billing period.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
CP Demand Charge (Demand 2 Charge)			
Demand Measure	Customer max demand during peak hours in the month		CP demand will be measured as a customer’s maximum demand during peak period hours during each billing period of the summer/winter.
Demand Calculation	Avg top 3 days customer max demand in billing month		CP billing demand will be calculated as the average of a customer’s three highest daily CP demands occurring during each billing period of the summer/winter.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer	Hours/day		
Peak	8		For this proposal, "summer months" are defined as June, July, August, and September. The on-peak period applies only to the summer/winter CP (Demand 2) charge. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Winter	Hours/day		
Peak	4		For this proposal, "winter months" are defined as December, January, February; The on-peak period applies only to the
Off Peak	20		During winter months, off peak hours are all hours that are not on peak
Non-Summer/Winter Months	Hours/day		
Peak	N/A		For this proposal, peak/off-peak periods are not applicable in non-summer/winter months for delivery demand charges.
Off Peak	N/A		

3. Delivery Rate Structures

Orange and Rockland Utilities, Inc. - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

p. Seasonal 4 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		Calculation of per kWh Charges is not applicable to JU's rate design proposal.
Demand Charges	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
NCP demand charge (Demand 1 charge)	N/A		The NCP (Demand 1) charge is to be applied to a customer's NCP billing demand (as defined below) in each billing period. As further described below, NCP billing demand is measured during all hours of the day, all days of the week; TOU periods do not apply to the measurement of NCP demand. The NCP (Demand 1) charge for both residential and small commercial non-demand (i.e., “mass market”) rate classifications is to be calculated by dividing (a) the rate class local distribution costs by (b) NCP billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution demand-related costs; and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. NCP billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification (the measurement of NCP billing demands is defined below).
CP demand charge (Demand 2 Charge)	N/A		The CP (Demand 2) charge is to be applied to a customer's CP billing demand (as defined below) in each summer billing period. As further described below, CP billing demand is measured during peak period hours only. The CP (Demand 2) charge for both mass market rate classifications is to be calculated by dividing (a) upstream delivery costs by (b) CP billing determinants. Upstream delivery costs include (a) the portion of primary distribution-related costs not included in local distribution costs and (b) transmission costs. CP billing determinants are the sum of the CP billing demands for all customers in each mass market rate classification (the measurement of CP billing demands is defined below). Upstream delivery costs and local distribution costs are utility-specific and based on each utility’s ECOS study.
Per kWh Charges	0%		Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

3. Delivery Rate Structures

Orange and Rockland Utilities, Inc. - 2 Demand Rate Approach			
NCP Demand Charge (Demand 1 Charge) - to shape summer / non-summer NCP Demand Charge (Demand 1 Charge) rates			
Summer Peak: Non-Summer Peak	1	: 1	Neither seasons nor TOU periods are applicable to the NCP Demand charge.
NCP Demand Charge (Demand 1 Charge) - to shape peak / off peak NCP Demand Charge (Demand 1 Charge) rates			
Peak: Off Peak, Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
Peak: Off Peak, Non-Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
CP Demand Charge (Demand 2 Charge) - to shape summer / non-summer CP Demand Charge (Demand 2 Charge) rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not Applicable: The CP (Demand 2) charge applies only in the summer, peak period.
CP Demand Charge (Demand 2 Charge) - to shape peak / off peak CP Demand Charge (Demand 2 Charge) rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
NCP Demand Charge (Demand 1 Charge)			Input direction/guidance for rate component
Demand Measure	Customer max demand during all hours in the month		NCP demand will be measured as a customer’s maximum demand during all hours of each day of the billing period.
Demand Calculation	Avg top 3 days customer max demand in billing month		NCP billing demand will be calculated as the average of a customer’s three highest daily demands in each billing period.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
CP Demand Charge (Demand 2 Charge)			
Demand Measure	Customer max demand during peak hours in the month		CP demand will be measured as a customer’s maximum demand during peak period hours during each billing period of the summer.
Demand Calculation	Avg top 3 days customer max demand in billing month		CP billing demand will be calculated as the average of a customer’s three highest daily CP demands occurring during each billing period of the summer.
Demand Metering Interval	60 minutes		Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer Months	Hours/day		
Peak	8		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. The on-peak period applies only to the summer CP (Demand 2) charge. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/day		
Peak	N/A		For this proposal, peak/off-peak periods are not applicable in non-summer months for delivery demand charges.
Off Peak	N/A		

3. Delivery Rate Structures

Rochester Gas and Electric Corporation - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

p. Seasonal 4 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		Calculation of per kWh Charges is not applicable to JU's rate design proposal.
Demand Charges	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
NCP demand charge (Demand 1 charge)	N/A		The NCP (Demand 1) charge is to be applied to a customer's NCP billing demand (as defined below) in each billing period. As further described below, NCP billing demand is measured during all hours of the day, all days of the week; TOU periods do not apply to the measurement of NCP demand. The NCP (Demand 1) charge for both residential and small commercial non-demand (i.e., “mass market”) rate classifications is to be calculated by dividing (a) the rate class local distribution costs by (b) NCP billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution demand-related costs; and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. NCP billing determinants are the sum of the NCP billing demands for all customers in each mass market rate classification (the measurement of NCP billing demands is defined below).
CP demand charge (Demand 2 Charge)	N/A		The CP (Demand 2) charge is to be applied to a customer's CP billing demand (as defined below) in each summer billing period. As further described below, CP billing demand is measured during peak period hours only. The CP (Demand 2) charge for both mass market rate classifications is to be calculated by dividing (a) upstream delivery costs by (b) CP billing determinants. Upstream delivery costs include (a) the portion of primary distribution-related costs not included in local distribution costs and (b) transmission costs. CP billing determinants are the sum of the CP billing demands for all customers in each mass market rate classification (the measurement of CP billing demands is defined below). Upstream delivery costs and local distribution costs are utility-specific and based on each utility’s ECOS study.
Per kWh Charges	0%		Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: The JU's proposed delivery rate design does not include a per kWh energy charge.

3. Delivery Rate Structures

Rochester Gas and Electric Corporation - 2 Demand Rate Approach

NCP Demand Charge (Demand 1 Charge) - to shape summer / non-summer NCP Demand Charge (Demand 1 Charge) rates			
Summer Peak: Non-Summer Peak	1	: 1	Neither seasons nor TOU periods are applicable to the NCP Demand charge.
NCP Demand Charge (Demand 1 Charge) - to shape peak / off peak NCP Demand Charge (Demand 1 Charge) rates			
Peak: Off Peak, Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
Peak: Off Peak, Non-Summer	1	: 1	The NCP (Demand 1) charge does not vary by season or TOU period.
CP Demand Charge (Demand 2 Charge) - to shape summer / non-summer CP Demand Charge (Demand 2 Charge) rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not Applicable: The CP (Demand 2) charge applies only in the summer, peak period.
CP Demand Charge (Demand 2 Charge) - to shape peak / off peak CP Demand Charge (Demand 2 Charge) rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable. The CP (Demand 2) charge does not apply to off-peak demand.

NCP Demand Charge (Demand 1 Charge)		Input direction/guidance for rate component
Demand Measure	Customer max demand during all hours in the month	NCP demand will be measured as a customer’s maximum demand during all hours of each day of the billing period.
Demand Calculation	Avg top 3 days customer max demand in billing month	NCP billing demand will be calculated as the average of a customer’s three highest daily demands in each billing period.
Demand Metering Interval	60 minutes	Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.
CP Demand Charge (Demand 2 Charge)		
Demand Measure	Customer max demand during peak hours in the month	CP demand will be measured as a customer’s maximum demand during peak period hours during each billing period of the summer.
Demand Calculation	Avg top 3 days customer max demand in billing month	CP billing demand will be calculated as the average of a customer’s three highest daily CP demands occurring during each billing period of the summer.
Demand Metering Interval	60 minutes	Daily demand will be measured as a customer's maximum daily demand in a 60-minute interval.

Peak Period Definition	
Peak period includes:	All non-holiday weekdays

Duration of TOU periods		
Summer Months	Hours/day	
Peak	8	For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. The on-peak period applies only to the summer CP (Demand 2) charge. On-peak hours are only during non-holiday weekdays.
Off Peak	16	During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/day	
Peak	N/A	For this proposal, peak/off-peak periods are not applicable in non-summer months for delivery demand charges.
Off Peak	N/A	

4. Supply Cost Recovery Approaches

Central Hudson Gas & Electric Corporation - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Annual capacity (ICAP) costs are recovered solely in the summer on-peak period energy (per kWh) charge.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (and as appropriate, hedging costs) will be calculated and recovered by billing period and on-peak and off-peak periods. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs, allowances for working capital costs and bad debts) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	5		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. Summer on-peak and off-peak periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	N/A		No distinction between peak and off peak periods
Off Peak	N/A		

4. Supply Cost Recovery Approaches

Consolidated Edison Company of New York - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Annual capacity (ICAP) costs are recovered solely in the summer on-peak period energy (per kWh) charge.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (and as appropriate, hedging costs) will be calculated and recovered by billing period and on-peak and off-peak periods. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	8		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. Summer on-peak and off-peak periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	N/A		No distinction between peak and off peak periods
Off Peak	N/A		

4. Supply Cost Recovery Approaches

National Grid - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Annual capacity (ICAP) costs are recovered solely in the summer on-peak period energy (per kWh) charge.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (and as appropriate, hedging costs) will be calculated and recovered by billing period. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, etc. ; other supply related costs such as RECs, ZECs and true-up components will continue to be recovered through the Company's current reconciliation mechanisms (ie, the ESRM)).

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	5		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. Summer on-peak and off-peak periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	N/A		No distinction between peak and off peak periods
Off Peak	N/A		

4. Supply Cost Recovery Approaches

New York State Electric & Gas Corporation - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Annual capacity (ICAP) costs are recovered solely in the summer on-peak period energy (per kWh) charge.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (supply will not be hedged) will be calculated and recovered by billing period and on-peak and off-peak periods. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	8		For this proposal, "summer months" are defined as June, July, August, September; Summer on-peak and off-peak periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Winter	Hours/day		
Peak	4		For this proposal, "winter months" are defined as December, January, February. Winter on-peak and off-peak periods are same for delivery and supply.
Off Peak	20		During winter months, off peak hours are all hours that are not on peak
Non Summer/Winter Months	Hours/day		
Peak	N/A		No distinction between peak and off peak periods
Off Peak	N/A		

4. Supply Cost Recovery Approaches

Orange and Rockland Utilities, Inc. - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Annual capacity (ICAP) costs are recovered solely in the summer on-peak period energy (per kWh) charge.

Please describe proposed method for recovering Commodity costs.

The service class load weighted forecasted energy prices (and as appropriate, hedging costs) will be calculated and recovered by billing period and on-peak and off-peak periods. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	8		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. Summer on-peak and off-peak periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	N/A		No distinction between peak and off peak periods
Off Peak	N/A		

4. Supply Cost Recovery Approaches

Rochester Gas and Electric Corporation - 2 Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Annual capacity (ICAP) costs are recovered solely in the summer on-peak period energy (per kWh) charge.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (supply will not be hedged) will be calculated and recovered by billing period and on-peak and off-peak periods. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	8		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. Summer on-peak and off-peak periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	N/A		No distinction between peak and off peak periods
Off Peak	N/A		

ATTACHMENTS F-I

TOU DEMAND RATE DESIGN PROPOSAL

1. Stakeholder(s) Identification

Color Code

Stakeholder input - enter value or text

a.	Stakeholder/Collaboration Name:	The Joint Utilities
b.	List of Organization(s)	
	1	Niagara Mohawk Power Company d/b/a/ National Grid
	2	Consolidated Edison Company of New York, Inc.
	3	Orange and Rockland Utilities, Inc.
	4	New York State Electric & Gas Corporation
	5	Rochester Gas and Electric Corporation
	6	Central Hudson Gas & Electric Corporation
c.	Stakeholder Contact Name(s)	
	1	Lauri Mancinelli
	2	William Atzl
	3	William Atzl
	4	Patti Beaudoin
	5	Patti Beaudoin
	6	Glynis Bunt
d.	Email Address(es) for Contact(s)	
	1	Lauri.Mancinelli@nationalgrid.com
	2	AtzlW@coned.com
	3	AtzlW@coned.com
	4	pabeaudoin@nyseg.com
	5	pabeaudoin@nyseg.com
	6	Gbunt@cenhud.com
e.	Phone Number(s) for Contact(s)	
	1	781-907-3809
	2	212- 460-3308
	3	212- 460-3308
	4	607-762-7061
	5	607-762-7061
	6	845-486-5420
f.	Proposal Name	JU_TOU Demand

2. Information fields to be entered by Stakeholder(s) for each Rate Design Proposal

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

a. Stakeholder and Proposal Name

Stakeholder/Collaboration Name:	The Joint Utilities
Proposal Name	JU_TOU Demand

b. Applicable Mass Market Service Class(es)

Current Mass Market service classes(es) for which this proposed rate design would apply.

Residential and Small Commercial Non-Demand

c. Is this rate design proposal for delivery or supply rates?

Delivery and Supply

d. Please select delivery rate design parameters to be included in proposals

Delivery Rate Design Parameters	Will the Rate Design Include each of the following? (Provide Yes / No responses from the drop down menu)
Customer Charge	Yes
Per kWh Rate	No
Demand Measure 1 Rate	Yes
Demand Measure 2 Rate	No
Seasonal	Yes
TOU	Yes
CPP	No
Other Delivery	

The Applicable Delivery Rate Design Parameter Input Section: Based on the responses provided above to the yes/no questions on Delivery rate design parameters, the cell below will indicate the area in Tab 3, Delivery with the input details for the indicated Delivery Rate Design Parameters.

3.i. Seasonal 3 Part TOU

e. Please select supply rate design parameters to be included in proposals

Supply Rate Design	Monthly Peak, Off Peak Supply pricing

The Applicable Supply Rate Design Parameter Input Section: Based on the responses provided above to the Supply rate design parameter, the cell below will indicate the area in Tab 4, Supply, with the input details for the indicated Supply Rate Design Parameters.

4.b. Monthly Peak, Off Peak Supply pricing

f. Overall Rate Design objective: In one or two sentences, describe the rate design proposal and the expected effect of the proposed rate design on new DER customers. [Limit to 2000 Characters]

The proposed delivery rate design includes: a fixed customer charge, and peak and off-peak demand charges by season. Initially, the proposed customer charge is set at each utility's current (as of 4/1/18) approved customer charge. The proposed peak and off-peak demand charges are calculated to recover the level of delivery revenues that is currently recovered through kWh charges. See 2.i for additional detail.

The seasons and peak and off-peak periods are determined by each utility, based on utility-specific data and analysis. The "high demand" season consists of certain months in the summer, for all utilities except NYSEG, and certain months in the summer and winter for NYSEG. For all utilities, the peak and off-peak periods are the same for delivery and supply charges

Peak billing demand and off-peak billing demand is defined as the average of a customer's three highest daily demands occurring during the peak period and off-peak period, respectively, in a billing period.

Supply energy costs will be recovered through volumetric peak and off-peak kWh charges that vary on a monthly basis. Capacity (ICAP) costs will be recovered each month on a per kWh basis applied to the peak period energy charges.

The proposed rate design will significantly improve the accuracy and clarity of price signals, which will allow customers to make more economically efficient decisions regarding DER investment and energy usage. The benefits of DER investments to a new DER customer will be reflected in cost-based supply and delivery rates that appropriately vary by TOU period and season.

g.	Referring to the Rate Design Principles that were adopted by the Commission in the Track Two Order, please (i) indicate the Rate Design Principles that the Stakeholder considers to be most important and (ii) how the Rate Design Proposal addresses the indicated principles. [Limit to 2000 Characters]
	This proposal considers all Rate Design Principles but strikes a reasoned balance among the principles deemed most important by the JU: cost causation, customer orientation, and economic sustainability. This proposal marks a critical step forward in the application of the principle of cost causation, which is a vital component of REV rate design, to the mass market rates. Because utility systems are built to serve demands at the customer, local, upstream and bulk power system levels, the delivery-related costs are based on customers' demands; the proposed delivery peak and off-peak demand charges reflect this relationship between customer demands and utility costs. In contrast, the current mass market volumetric rate structures provide inefficient price signals that do not reflect that utility distribution costs are driven by customer demand. The proposed peak and off-peak supply energy (per kWh) charges reflect that supply costs are driven by the time of use. Customers considering DERs will be able to make informed decisions on investments in DER; energy-consuming and energy-conserving equipment; and behavioral changes because the proposed delivery demand charges and the supply charges provide more efficient price signals. Thus, this rate design proposal is a significant step towards a long-term vision of price signals for traditional and prosumer mass market customers that will be economically sustainable. This proposal is customer-oriented: the growing body of experience with mass market demand rates in the US demonstrates that - with the JU-provided customer education – the rate design proposal is understandable to mass market customers and will promote economically efficient consumption and investment decisions.

h. Rate Design Qualitative Benefits: Provide any additional benefits of the proposed rates that may not have been included in the rate design criteria. [Limit to 2000 Characters]

The price signals that are inherent in this proposal encourage support for REV objectives while also allowing customers to manage energy use. This rate design improves the price signals to mass market customers provided by delivery rates not only by introducing kW demand charges to recover demand-related delivery costs, but also by providing separate price signals for local distribution costs, which are associated with the peak and off-peak demand charges and the upstream delivery costs, which are associated solely with the seasonal peak demand charges.

Because current volumetric rate design for mass market customers is not aligned with demand-driven utility costs, customers and DER developers today receive improper price signals that drive decisions and investments that are not beneficial to the general body of electric utility customers and the electric grid as a whole. These price signals, which are misaligned with utility costs, confuse customer decision-making and result in inefficient DER investments.

This proposal addresses concerns articulated by the Commission in its March 9, 2017 Order on net energy metering (NEM) ("Order"), which states "especially when coupled with volumetric rate structures, NEM does not provide sufficient information to serve as a basis of efficient investment decisions …. For most customers compensated under NEM, compensation … has little or no relationship to the actual values provided to or costs imposed on the system." (Order, p. 21). The Order finds that this may lead to the installation of DERs that creates lower benefits or higher costs for the electric grid than would otherwise be efficient. The Commission states that "all utility customers, and in particular non-participants, suffer the impacts of those greater costs and lower benefits." (Id.) This proposal addresses this concern by sending correct price signals, which will advance REV goals and benefit customers and the grid.

i. Additional information or guidance: Provide any additional information or guidance to support selecting and prioritizing the rate design proposal or in supporting the rate design and bill impact analysis.
[Limit to 2000 Characters]

To further explain the the JU's TOU Demand delivery rate design proposal, which is provided in the Input Workbook Tab 2.f and Tab 3.i, the seasonal peak period demand charges are designed to recover: (a) a portion of the rate class local distribution costs, (b) upstream distribution costs; and (c) transmission costs. The off-peak demand charges are designed to recover a portion of the local distribution costs.

The TOU Demand proposal may be described as consisting of a "base" demand rate layer that is included in both the peak and off-peak demand charges of each season, and an "incremental" demand rate layer on top of the base rate layer during peak periods of each season. The base rate layer is designed to recover local distribution costs and the incremental rate layer is designed to recover upstream delivery costs. The off-peak period demand charge is the same as the base rate and the peak period demand charge is the sum of the incremental peak demand rate and the base rate. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis.
Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study. The proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results.

RG&E, Con Ed, O&R, Grid, and CH determined that their high demand season occurs in certain summer months; NYSEG determined that its high demand season occurs in certain summer and winter months. NYSEG has identified a shoulder season comprised of all months that are not included in the summer or winter seasons.

3. Delivery Rate Structures

Central Hudson Gas & Electric Corporation - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

i. Seasonal 3 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Demand Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
Demand Charges	100%		
Per kWh Charges	0%		Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Demand Charges - to shape summer / non-summer demand rates			
Summer Peak: Non-Summer Peak	N/A	: 1	As described below, the JU's proposed delivery peak demand charges for both residential and small commercial non-demand (i.e., “mass market”) rate classifications in the summer and non-summer seasons are to be calculated by summing (a) a "base" demand rate layer that applies to peak and off-peak hours of the summer and non-summer seasons, and (b) "incremental" summer and non-summer demand rate layers that apply to the peak hours of the summer and non-summer seasons, respectively.

3. Delivery Rate Structures

Central Hudson Gas & Electric Corporation - TOU Demand Rate Approach

Demand Charges - to shape peak / off peak demand rates			
Peak: Off Peak, Summer	N/A	: 1	In both the summer and non-summer seasons, the off-peak demand charge for both mass market rate classifications is equal to the "base" demand rate layer. The base demand rate layer is calculated by dividing (a) the rate class local distribution costs by (b) base demand billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. Base demand billing determinants are the sum of the peak and off-peak billing demands for all customers for each mass market rate classification (the measurement of peak and off-peak billing demands is defined below). The summer and non-summer peak demand charges for both mass market rate classifications are equal to the sum of (a) the "base" demand rate layer (defined above) and (b) summer and non-summer "incremental" demand rate layers, respectively. Summer and non-summer "incremental" demand rate layers are calculated by dividing (a) summer and non-summer upstream delivery costs by (b) summer and non-summer peak demand billing determinants, respectively. Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility’s ECOS study.
Peak: Off Peak, Non-Summer	N/A	: 1	
Demand Measure	Customer max demand during peak and off peak hours in the month		Peak demand will be measured during hours of the peak period for each applicable day of the billing period. Hours of the peak period may be different for each season. Also: Off-Peak demand will be measured during hours of the off-peak period for each day of the billing period. Hours of the off-peak period may be different for each season. Peak and off-peak periods and summer and non-summer seasons are as defined below.
Demand Calculation	Avg top 3 days customer max demand in billing month		In each billing period, peak billing demand will be calculated as the average of a customer’s three highest daily demands occurring during the peak period; off-peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the off-peak period.
Demand Metering Interval	60 minutes		Daily demand will be measured separately in peak and off-peak periods as a customer's maximum demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer Months	Hours/Day		
Peak	5		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/Day		
Peak	5		"Non-summer months" are October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During non-summer months, off peak hours are all hours that are not on peak

3. Delivery Rate Structures

Consolidated Edison Company of New York - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

i. Seasonal 3 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Demand Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		

Of remaining class revenue requirement, what percentage should be recovered through			
Demand Charges	100%		
Per kWh Charges	0%		Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.

Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Demand Charges - to shape summer / non-summer demand rates			
Summer Peak: Non-Summer Peak	N/A	: 1	As described below, the JU's proposed delivery peak demand charges for both residential and small commercial non-demand (i.e., "mass market") rate classifications in the summer and non-summer seasons are to be calculated by summing (a) a "base" demand rate layer that applies to peak and off-peak hours of the summer and non-summer seasons, and (b) "incremental" summer and non-summer demand rate layers that apply to the peak hours of the summer and non-summer seasons, respectively.

3. Delivery Rate Structures

Consolidated Edison Company of New York - TOU Demand Rate Approach			
Demand Charges - to shape peak / off peak demand rates			
Peak: Off Peak, Summer	N/A	: 1	In both the summer and non-summer seasons, the off-peak demand charge for both mass market rate classifications is equal to the "base" demand rate layer. The base demand rate layer is calculated by dividing (a) the rate class local distribution costs by (b) base demand billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. Base demand billing determinants are the sum of the peak and off-peak billing demands for all customers for each mass market rate classification (the measurement of peak and off-peak billing demands is defined below). The summer and non-summer peak demand charges for both mass market rate classifications are equal to the sum of (a) the "base" demand rate layer (defined above) and (b) summer and non-summer "incremental" demand rate layers, respectively. Summer and non-summer "incremental" demand rate layers are calculated by dividing (a) summer and non-summer upstream delivery costs by (b) summer and non-summer peak demand billing determinants, respectively. Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Peak: Off Peak, Non-Summer	N/A	: 1	
Demand Measure	Customer max demand during peak and off peak hours in the month		Peak demand will be measured during hours of the peak period for each applicable day of the billing period. Hours of the peak period may be different for each season. Also: Off-Peak demand will be measured during hours of the off-peak period for each day of the billing period. Hours of the off-peak period may be different for each season. Peak and off-peak periods and summer and non-summer seasons are as defined below.
Demand Calculation	Avg top 3 days customer max demand in billing month		In each billing period, peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the peak period; off-peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the off-peak period.
Demand Metering Interval	60 minutes		Daily demand will be measured separately in peak and off-peak periods as a customer's maximum demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer Months	Hours/Day		
Peak	8		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/Day		
Peak	8		"Non-summer months" are October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During non-summer months, off peak hours are all hours that are not on peak

3. Delivery Rate Structures

National Grid - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

i. Seasonal 3 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Demand Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
Demand Charges	100%		
Per kWh Charges	0%		Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Demand Charges - to shape summer / non-summer demand rates			
Summer Peak: Non-Summer Peak	N/A	: 1	As described below, the JU's proposed delivery peak demand charges for both residential and small commercial non-demand (i.e., “mass market”) rate classifications in the summer and non-summer seasons are to be calculated by summing (a) a "base" demand rate layer that applies to peak and off-peak hours of the summer and non-summer seasons, and (b) "incremental" summer and non-summer demand rate layers that apply to the peak hours of the summer and non-summer seasons, respectively.

3. Delivery Rate Structures

National Grid - TOU Demand Rate Approach

Demand Charges - to shape peak / off peak demand rates			
Peak: Off Peak, Summer	N/A	: 1	In both the summer and non-summer seasons, the off-peak demand charge for both mass market rate classifications is equal to the "base" demand rate layer. The base demand rate layer is calculated by dividing (a) the rate class local distribution costs by (b) base demand billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. Base demand billing determinants are the sum of the peak and off-peak billing demands for all customers for each mass market rate classification (the measurement of peak and off-peak billing demands is defined below). The summer and non-summer peak demand charges for both mass market rate classifications are equal to the sum of (a) the "base" demand rate layer (defined above) and (b) summer and non-summer "incremental" demand rate layers, respectively. Summer and non-summer "incremental" demand rate layers are calculated by dividing (a) summer and non-summer upstream delivery costs by (b) summer and non-summer peak demand billing determinants, respectively. Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Peak: Off Peak, Non-Summer	N/A	: 1	
Demand Measure	Customer max demand during peak and off peak hours in the month		Peak demand will be measured during hours of the peak period for each applicable day of the billing period. Hours of the peak period may be different for each season. Also: Off-Peak demand will be measured during hours of the off-peak period for each day of the billing period. Hours of the off-peak period may be different for each season. Peak and off-peak periods and summer and non-summer seasons are as defined below.
Demand Calculation	Avg top 3 days customer max demand in billing month		In each billing period, peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the peak period; off-peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the off-peak period.
Demand Metering Interval	60 minutes		Daily demand will be measured separately in peak and off-peak periods as a customer's maximum demand in a 60-minute interval.

Peak Period Definition			
Peak period includes:	All non-holiday weekdays		

Duration of TOU periods			
Summer Months	Hours/Day		
Peak	5		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/Day		
Peak	5		"Non-summer months" are October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During non-summer months, off peak hours are all hours that are not on peak

3. Delivery Rate Structures

New York State Electric & Gas Corporation - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

i. Seasonal 3 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Demand Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
Demand Charges	100%		
Per kWh Charges	0%		Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape Summer/Winter / non-Summer/Winter per kWh rates			
Summer/Winter Peak: Non-Summer/Winter Peak	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer/Winter	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer/Winter	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Demand Charges - to shape Summer/Winter / non-Summer/Winter demand rates			
Summer/Winter Peak: Non-Summer/Winter Peak	N/A	: 1	As described below, the JU's proposed delivery peak demand charges for both residential and small commercial non-demand (i.e., "mass market") rate classifications in the summer/winter and non-summer/winter seasons are to be calculated by summing (a) a "base" demand rate layer that applies to peak and off-peak hours of the summer/winter and non-summer/winter seasons, and (b) "incremental" summer/winter and non-summer/winter demand rate layers that apply to the peak hours of the summer/winter and non-summer/winter seasons, respectively.

3. Delivery Rate Structures

New York State Electric & Gas Corporation - TOU Demand Rate Approach

Demand Charges - to shape peak / off peak demand rates			
Peak: Off Peak, Summer/Winter	N/A	: 1	In both the summer/winter and non-summer/winter seasons, the off-peak demand charge for both mass market rate classifications is equal to the "base" demand rate layer. The base demand rate layer is calculated by dividing (a) the rate class local distribution costs by (b) base demand billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. Base demand billing determinants are the sum of the peak and off-peak billing demands for all customers for each mass market rate classification (the measurement of peak and off-peak billing demands is defined below). The summer/winter and non-summer/winter peak demand charges for both mass market rate classifications are equal to the sum of (a) the "base" demand rate layer (defined above) and (b) summer/winter and non-summer/winter "incremental" demand rate layers, respectively. Summer/winter and non-summer/winter "incremental" demand rate layers are calculated by dividing (a) summer/winter and non-summer/winter upstream delivery costs by (b) summer/winter and non-summer/winter peak demand billing determinants, respectively. Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Peak: Off Peak, Non-Summer/Winter	N/A	: 1	
Demand Measure	Customer max demand during peak and off peak hours in the month		Peak demand will be measured during hours of the peak period for each applicable day of the billing period. Hours of the peak period may be different for each season. Also: Off-Peak demand will be measured during hours of the off-peak period for each day of the billing period. Hours of the off-peak period may be different for each season. Peak and off-peak periods and summer and non-summer seasons are as defined below.
Demand Calculation	Avg top 3 days customer max demand in billing month		In each billing period, peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the peak period; off-peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the off-peak period.
Demand Metering Interval	60 minutes		Daily demand will be measured separately in peak and off-peak periods as a customer's maximum demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer/Winter Months	Hours/Day		
Peak	9		For this proposal, "summer/winter months" are defined as June, July, August, September, December, January, and February; and "non-summer/winter months" are all remaining months. On-peak hours are only during non-holiday weekdays.
Off Peak	15		During summer/winter months, off peak hours are all hours that are not on peak
Non-Summer/Winter Months	Hours/Day		
Peak	9		For this proposal, "non-summer/winter months" are defined as March, April, May, October, and November. On-peak hours
Off Peak	15		During non-summer/winter months, off peak hours are all hours that are not on peak

3. Delivery Rate Structures

Orange and Rockland Utilities, Inc. - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

i. Seasonal 3 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Demand Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		

Of remaining class revenue requirement, what percentage should be recovered through			
Demand Charges	100%		
Per kWh Charges	0%		Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Demand Charges - to shape summer / non-summer demand rates			
Summer Peak: Non-Summer Peak	N/A	: 1	As described below, the JU's proposed delivery peak demand charges for both residential and small commercial non-demand (i.e., "mass market") rate classifications in the summer and non-summer seasons are to be calculated by summing (a) a "base" demand rate layer that applies to peak and off-peak hours of the summer and non-summer seasons, and (b) "incremental" summer and non-summer demand rate layers that apply to the peak hours of the summer and non-summer seasons, respectively.

3. Delivery Rate Structures

Orange and Rockland Utilities, Inc. - TOU Demand Rate Approach			
Demand Charges - to shape peak / off peak demand rates			
Peak: Off Peak, Summer	N/A	: 1	In both the summer and non-summer seasons, the off-peak demand charge for both mass market rate classifications is equal to the "base" demand rate layer. The base demand rate layer is calculated by dividing (a) the rate class local distribution costs by (b) base demand billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. Base demand billing determinants are the sum of the peak and off-peak billing demands for all customers for each mass market rate classification (the measurement of peak and off-peak billing demands is defined below). The summer and non-summer peak demand charges for both mass market rate classifications are equal to the sum of (a) the "base" demand rate layer (defined above) and (b) summer and non-summer "incremental" demand rate layers, respectively. Summer and non-summer "incremental" demand rate layers are calculated by dividing (a) summer and non-summer upstream delivery costs by (b) summer and non-summer peak demand billing determinants, respectively. Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Peak: Off Peak, Non-Summer	N/A	: 1	
Demand Measure	Customer max demand during peak and off peak hours in the month		Peak demand will be measured during hours of the peak period for each applicable day of the billing period. Hours of the peak period may be different for each season. Also: Off-Peak demand will be measured during hours of the off-peak period for each day of the billing period. Hours of the off-peak period may be different for each season. Peak and off-peak periods and summer and non-summer seasons are as defined below.
Demand Calculation	Avg top 3 days customer max demand in billing month		In each billing period, peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the peak period; off-peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the off-peak period.
Demand Metering Interval	60 minutes		Daily demand will be measured separately in peak and off-peak periods as a customer's maximum demand in a 60-minute interval.
Peak Period Definition			
Peak period includes:	All non-holiday weekdays		
Duration of TOU periods			
Summer Months	Hours/Day		
Peak	8		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/Day		
Peak	8		"Non-summer months" are October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During non-summer months, off peak hours are all hours that are not on peak

3. Delivery Rate Structures

Rochester Gas and Electric Corporation - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

i. Seasonal 3 Part TOU

			Input direction/guidance for rate component
Customer Charge	100%	of current customer charge	Set customer charge equal to current level, effective as of 4/1/2018.
Per kWh Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Demand Charge	To be calculated, based on Stakeholder's Rate Design Proposal guidance, for all Rate Design Proposals that remain after Staff's down-select process.		
Of remaining class revenue requirement, what percentage should be recovered through			
Demand Charges	100%		
Per kWh Charges	0%		Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Please provide the following price ratios:			
Per kWh Charges - to shape summer / non-summer per kWh rates			
Summer Peak: Non-Summer Peak	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Per kWh Charges - to shape peak / off peak per kWh rates			
Peak: Off Peak, Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Peak: Off Peak, Non-Summer	N/A	: 1	Not applicable: JU's proposed delivery rate design does not include a per kWh energy charge.
Demand Charges - to shape summer / non-summer demand rates			
Summer Peak: Non-Summer Peak	N/A	: 1	As described below, the JU's proposed delivery peak demand charges for both residential and small commercial non-demand (i.e., "mass market") rate classifications in the summer and non-summer seasons are to be calculated by summing (a) a "base" demand rate layer that applies to peak and off-peak hours of the summer and non-summer seasons, and (b) "incremental" summer and non-summer demand rate layers that apply to the peak hours of the summer and non-summer seasons, respectively.

3. Delivery Rate Structures

Rochester Gas and Electric Corporation - TOU Demand Rate Approach

Demand Charges - to shape peak / off peak demand rates			
Peak: Off Peak, Summer	N/A	: 1	In both the summer and non-summer seasons, the off-peak demand charge for both mass market rate classifications is equal to the "base" demand rate layer. The base demand rate layer is calculated by dividing (a) the rate class local distribution costs by (b) base demand billing determinants. Local distribution costs include (a) customer-related costs that are not recovered in the current (and proposed) customer charge; (b) secondary distribution costs and (c) a portion of primary distribution costs, which will be determined on a utility specific basis. Because the proposed and current (as of 4/1/18) customer charges for all utilities are less than total customer-related ECOS study results, not all customer-related costs are recovered in the current (and proposed) customer charge. Base demand billing determinants are the sum of the peak and off-peak billing demands for all customers for each mass market rate classification (the measurement of peak and off-peak billing demands is defined below). The summer and non-summer peak demand charges for both mass market rate classifications are equal to the sum of (a) the "base" demand rate layer (defined above) and (b) summer and non-summer "incremental" demand rate layers, respectively. Summer and non-summer "incremental" demand rate layers are calculated by dividing (a) summer and non-summer upstream delivery costs by (b) summer and non-summer peak demand billing determinants, respectively. Upstream delivery costs include (a) the portion of primary distribution costs that are not local distribution costs and (b) transmission costs. Upstream delivery costs and local distribution costs are utility-specific and based on each utility's ECOS study.
Peak: Off Peak, Non-Summer	N/A	: 1	
Demand Measure	Customer max demand during peak and off peak hours in the month		Peak demand will be measured during hours of the peak period for each applicable day of the billing period. Hours of the peak period may be different for each season. Also: Off-Peak demand will be measured during hours of the off-peak period for each day of the billing period. Hours of the off-peak period may be different for each season. Peak and off-peak periods and summer and non-summer seasons are as defined below.
Demand Calculation	Avg top 3 days customer max demand in billing month		In each billing period, peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the peak period; off-peak billing demand will be calculated as the average of a customer's three highest daily demands occurring during the off-peak period.
Demand Metering Interval	60 minutes		Daily demand will be measured separately in peak and off-peak periods as a customer's maximum demand in a 60-minute interval.

Peak Period Definition			
Peak period includes:	All non-holiday weekdays		

Duration of TOU periods			
Summer Months	Hours/Day		
Peak	9		For this proposal, "summer months" are defined as June, July, August and September; and "non-summer months" are all remaining months. On-peak hours are only during non-holiday weekdays.
Off Peak	15		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months	Hours/Day		
Peak	9		"Non-summer months" are October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	15		During non-summer months, off peak hours are all hours that are not on peak

4. Supply Cost Recovery Approaches

Central Hudson Gas & Electric Corporation - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Capacity (ICAP) costs will be recovered year-round during peak periods on a $/kWh basis.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (and as appropriate, hedging costs) will be calculated and recovered by billing period and TOU period. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs, allowances for working capital costs and bad debts) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	5		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. Summer TOU periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	5		"Non-summer months" are defined as October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During non-summer months, off peak hours are all hours that are not on peak

4. Supply Cost Recovery Approaches

Consolidated Edison Company of New York - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Capacity (ICAP) costs will be recovered year-round during peak periods on a $/kWh basis.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (and as appropriate, hedging costs) will be calculated and recovered by billing period and TOU period. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	8		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. Summer TOU periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	8		"Non-summer months" are defined as October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During non-summer months, off peak hours are all hours that are not on peak

4. Supply Cost Recovery Approaches

National Grid - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Capacity (ICAP) costs will be recovered year-round during peak periods on a $/kWh basis.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (and as appropriate, hedging costs) will be calculated and recovered by billing period. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, etc. ; other supply related costs such as RECs, ZECs and true-up components will continue to be recovered through the Company's current reconciliation mechanisms (i.e., the ESRM)).

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	5		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. Summer TOU periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	5		"Non-summer months" are defined as October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	19		During non-summer months, off peak hours are all hours that are not on peak

4. Supply Cost Recovery Approaches

New York State Electric & Gas Corporation - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Capacity (ICAP) costs will be recovered year-round during peak periods on a $/kWh basis.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (supply will not be hedged) will be calculated and recovered by billing period and TOU period. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer/Winter Months	Hours/day		Comments
Peak	9		For this proposal, "summer/winter months" are defined as June, July, August, September, December, January, and February; and "non-Summer/winter months" are all remaining months. Summer/winter TOU periods are same for delivery and supply. On-peak hours are only during
Off Peak	15		During summer/winter months, off peak hours are all hours that are not on peak
Non-Summer/Winter Months			
Peak	9		For this proposal, "non-summer/winter months" are defined as March, April, May, October, and November. On-peak hours are only during non-
Off Peak	15		During non-summer/winter months, off peak hours are all hours that are not on peak

4. Supply Cost Recovery Approaches

Orange and Rockland Utilities, Inc. - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Capacity (ICAP) costs will be recovered year-round during peak periods on a $/kWh basis.

Please describe proposed method for recovering Commodity costs.

The service class load weighted forecasted energy prices (and as appropriate, hedging costs) will be calculated and recovered by billing period and on-peak and off-peak periods. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	8		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. Summer TOU periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	8		"Non-summer months" are defined as October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	16		During non-summer months, off peak hours are all hours that are not on peak

4. Supply Cost Recovery Approaches

Rochester Gas and Electric Corporation - TOU Demand Rate Approach

Color Code

Stakeholder input - enter value or text
Stakeholder input - select from drop-down menu.

b. Monthly Peak, Off Peak Supply pricing

Please describe proposed method for recovering ICAP costs.

Capacity (ICAP) costs will be recovered year-round during peak periods on a $/kWh basis.

Please describe proposed method for recovering Commodity costs.

The service class load weighted average NYISO day-ahead LBMP price (supply will not be hedged) will be calculated and recovered by billing period and TOU period. These costs will be recovered through volumetric per kWh charges, which will also include recovery of other supply-related costs (e.g. ancillary, NTAC, RECs, ZECs) and true-up components will continue to be recovered through the Company's current reconciliation mechanisms.

Duration of TOU periods

Summer Months	Hours/day		Comments
Peak	9		For this proposal, "summer months" are defined as June, July, August, and September; and "non-summer months" are all remaining months. Summer TOU periods are same for delivery and supply. On-peak hours are only during non-holiday weekdays.
Off Peak	15		During summer months, off peak hours are all hours that are not on peak
Non-Summer Months			
Peak	9		"Non-summer months" are defined as October through May. On-peak hours are only during non-holiday weekdays.
Off Peak	15		During non-summer months, off peak hours are all hours that are not on peak