VDER Rate Design Working Group
RATE DESIGN PROPOSAL HANDBOOK

Prepared by
Joint Utilities
Concentric Energy Advisors

April 10, 2018
First revision April 12, 2018
Second revision April 27, 2018

Contents

List of Revisions

Date	Description
April 10, 2018	Initial filing
April 12, 2018	Page 41 of the Rate Design Proposal Handbook has been updated to include instructions regarding the dissemination of aggregated system 8670 hour load data for each utility. In addition, Niagara Mohawk's allowed Small Commercial Non-Demand customer charge shown in the chart on page 36 has been corrected.
April 27, 2018	Page 42 of the Rate Design Proposal Handbook has been updated to include instructions regarding the dissemination of class load shape profiles for each utility.

I. Introduction

This Rate Design handbook, together with the Rate Design Input Worksheet serve to define and explain the uniform approach that the Joint Utilities have developed for parties to submit rate design proposals. JU has also developed the process and schedule summarized in Table 1, below, for parties to submit rate design proposals.

Table 1 Schedule for Rate Design Proposals

	Responsibility / Task	Deadline
1.	**JU** makes Rate Design Proposal presentation	April 6
2.	**JU** distributes Rate Design Input Worksheet and Handbook to Stakeholders	April 10
3.	**Stakeholders** and **JU** submit Rate Design Proposals	May 23
4.	**Staff** to down select proposals based on application of rate design principles	June 4
5.	**JU** calculates initial rates based on Stakeholder Rate Design Proposals; conducts discussions with each **Stakeholder** on the calculated rates associated with their Rate Design Proposal.	June 30

II. Instructions for Completing Rate Design Input Worksheet

A. Tab 1: Stakeholder ID

The Stakeholder ID sheet is intended to collect information concerning the organization or organizations[1] that have prepared this proposed Rate Design. The information requested in the Stakeholder ID sheet is explained in Table 2, below.

Table 2 Tab 1 Input Details

	Input Label	**Input Explanation**
1.a.	Stakeholder/Collaboration Name:	If this proposal is prepared by a group of Stakeholder organizations, please create a Collaboration Name. Please include a shortened version of the Stakeholder/Collaboration Name in the Excel file name for the Rate Design Input Workbook.
1.b.	List of Organization(s)	Please insert additional rows in 1.a – 1.e if there are more than five organizations in the collaboration group.
1.c.	Stakeholder Contact Name(s)	The JU Companies may wish to use the Stakeholder contact information in 1.b through 1.e to clarify questions on the Rate Design proposal.
1.d.	Email Address(es) for Contact(s)	
1.e.	Phone Number(s) for Contact(s)	
1.f.	Proposal Name	Please assign a unique name to the Rate Design proposal using the format: (Stakeholder name).(delivery / commodity).(number). For example, if the Collaboration

[1] Organizations with the same or similar positions on rate design for VDER Phase Two rates or, mass market NEM successor tariffs, are encouraged to collaborate in the development of joint rate design proposals.

		Group, “JU” were to make a Rate Design proposal for delivery rates, their first Rate Design proposal would be: JU.delivery.1 Please create separate Excel files for each distinct Rate Design proposal. For example, if the Collaboration Group, “JU” were to make two Rate Design proposals for delivery rates, the Excel file for their first Rate Design proposal would be: JU.delivery.1.xlsx and the Excel file for their second proposal would be JU.delivery.2.xlsx

B. Tab 2: Proposal Overview

The Proposal Overview sheet is intended to (1) collect information on the utilities and rate classifications to which the Stakeholder / Collaboration Group’s Rate Design Proposal would apply, and (2) allow the Stakeholder / Collaboration Group to describe and provide support for their Rate Design proposal. The information requested in the Proposal Overview sheet is explained in Table 3.

Table 3 Tab 2 Input Details

	Input Label	**Input Explanation**
2.a.	Stakeholder and Proposal Name	Copy names from 1.a and 1.f.
2.b.	Applicable Mass Market Service Class(es)	Indicate if the Rate Design proposal applies to Residential, Small non-demand Commercial, or both.
2.c.	Delivery / Supply rates	Indicate if the Rate Design proposal applies to Delivery rates, Supply Rates, or both.
2.d.	Rate Design parameters for Delivery Rate Design Proposal	To determine the rate structure for Stakeholder’s Delivery rate design proposal, select “yes” and “no” from the drop-down menus for each of the eight rate design parameters listed. Based on the yes / no responses, the rate structure for Stakeholder’s rate design proposal will be identified (in Cell D32 of the Input Workbook) and the Stakeholder will be directed to the applicable input section in Tab 3, Delivery, for that rate structure.
2.e	Rate Design parameters for Supply Rate Design Proposal	To determine the cost recovery approach for Stakeholder’s Supply rate design proposal, select the appropriate option from the drop-down menu. Based on the selected option, the cost recovery approach for Stakeholder’s Supply rate design proposal will be identified (in Cell D39 of the Input Workbook) and the Stakeholder will be directed to the applicable input section in Tab 4, Supply.
2.f	Overall objective of the Rate Design proposal	To help parties understand the Rate Design proposal please provide a short description of the rate design proposal and the effect that Stakeholder expects the Rate Design proposal to have.
2.g	Important Applicable Rate Design Principles	The Commission adopted the following Rate Design Principles in the Track Two Order: Cost causation,

	Input Label	Input Explanation
		Encourage outcomes, Policy transparency, Decision-making, Fair value, Customer-orientation, Stability, Access, Gradualism, and Economic sustainability.[2] Please identify the principles that Stakeholder considers to be the most important, and indicate how the Rate Design Proposal addresses and advances those principles.
2.h	Qualitative Benefits	In addition to any benefits to the Rate Design Proposal described above in 2.f and 2.g, please identify and explain any additional benefits that the Stakeholders expect to be provided by the Rate Design Proposal.
2.i	Additional Information and guidance[3]	Please provide any information concerning Stakeholder's Rate Design Proposal that has not been provided in 2.f, 2.g and 2.h that will help other parties understand and assess the merits of the Rate Design Proposal. Also, JU anticipates that Stakeholders will submit Rate Design proposals for both Delivery and Supply rates. If Stakeholder is submitting more than one Delivery Rate Design proposal and / or Supply Rate Design Proposal, please provide specific instructions in the space provided in the Input Worksheet for Stakeholder's "Additional information and guidance" (Section 2.i) concerning intended pairings of the Delivery and Supply Rate Design proposals.[4]

[2] These Rate Design Principles are defined in "Department of Public Service Staff Guiding Instructions to Utilities and Stakeholders on the Approach/Implementation of Mass Market Rate Reform and Bill Impact Analysis, VDER Rate Design Working Group, January 30, 2018, at 6.

[3] Stakeholders may wish to identify a proposed treatment/ value of DER injections into the grid. The general assumption for this process is that issue is being generally addressed outside the scope of this Rate Design Input Proposal process. However, given that the treatment/ value of DER injections into the grid may affect the bill impact analysis for some rate design proposal, parties may specify their preferred treatment/ value of such DER injections. However, the actual decision regarding such value may ultimately be determined outside the scope of this process.

If Stakeholder wishes to identify a proposed treatment/ value/ compensation for DER injections, they should do so in this Section 2i.

[4] For example, "JU.Commodity.1 is to be combined with JU.Delivery.1 and with JU.Delivery.2.

C. Tab 3: Delivery Rate Structures

The Delivery Rate Design Tab is designed to collect information and guidance on Stakeholders' proposed Delivery rate structures and rate design parameters for Residential and Small Commercial Non-Demand service classifications. The information requested in the Tab 3 Delivery sheet is explained in Table 4, below.

To inform Stakeholder's Rate Design proposals, the following information is available in Section III. Reference Data:

- III.A Fundamentals of Rate Design: An overview of rate design and NY utility cost data; this information was included in the JU February 8, 2018 presentation.
- III.B JU ECOS Approach and Results: Details on the functionalization and classification of costs in each JU utility's ECOS study with emphasis on classification of Distribution costs between "Customer Related" and "Demand Related;" this information was included in the JU March 6, 2018 presentation.
- III.C JU ECOS Summary Charts: Charts showing (a) Customer-related cost per bill by JU utility and (b) a comparison of customer-related costs and current customer charges; this information was also included in the JU March 6, 2018 presentation.
- III.D JU Current Residential and Small Commercial Non-Demand Rates
- III.E JU Residential and Small Commercial Non-Demand Billing determinants applicable to current service classification rates: The sources for the provided billing determinants is included, for each JU utility.
- JU Load Data

Table 4 Tab 3 Delivery Rate Design Input Details

Preliminary note: At the conclusion of Staff's down select process, the JU utilities will calculate the delivery rates for the remaining Rate Design proposals. The JU utilities will first determine the billing determinants for each remaining proposal and will then calculate all rate components for each proposal based on the (a) service classification revenue requirement, and (b) all applicable proposed allocation percentages, price ratios, seasons, TOU periods and definitions of demand. The Delivery Rate Design inputs have been designed to avoid JU judgement; there is one unique set of rates that meets the requirements of the Stakeholder-provided rate design inputs for a given service classification revenue requirement and billing determinants.

	Input Label	Input Explanation
3.a.	2 Part	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge.
3.b.	Seasonal 2 Part	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge and • The ratio of the proposed summer per kWh (energy) charge to non-summer energy charge.
3.c1	2 Part TOU	For Stakeholder's Delivery Rate Design Proposal, please indicate

	Input Label	Input Explanation
		• The proposed Customer charge, expressed as a percent of the Companies' current Customer charge and • The ratio of the proposed Peak period per kWh (energy) charge to the Off-peak energy charge. • Also indicate Stakeholder's proposed duration of Peak period hours and the days of the week that are to be included in the proposed peak period.
3.c2	2 Part CPP	For Stakeholder's Delivery Rate Design Proposal, please indicate • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge; • The ratio of the proposed Critical Peak Period per kWh (energy) charge to the Off-peak energy charge.; and • The ratio of the proposed Peak period per kWh (energy) charge to the Off-peak energy charge. • Indicate Stakeholder's proposed duration of the Peak period hours and the days of the week that are to be included in the proposed peak period. • Also indicate how a Critical Peak event day will be determined

3.d1	Seasonal 2 Part TOU	For Stakeholder Delivery Rate Design Proposal, please indicate
		• The proposed Customer charge, expressed as a percent of the Companies' current Customer charge and
		• All of the following ratios:
		  - Summer Peak period energy charge to the non-Summer Peak period energy charge.
		  - Summer Peak Period energy charge to the Summer Off-peak energy charge
		  - Non-summer Peak Period energy charge to the non-Summer Off-peak energy charge
		• Also indicate the duration of
		  - Summer week day Peak period and
		  - non-Summer week day Peak period.
		• Also indicate Stakeholder's proposed duration of Peak period hours and the days of the week that are to be included in the proposed peak period.

3.d2	Seasonal 2 Part CPP	For Stakeholder Delivery Rate Design Proposal, please indicate
		• The proposed Customer charge, expressed as a percent of the Companies' current Customer charge and
		• All of the following ratios:
		  - Summer Critical Peak Period energy charge to the Summer Off-peak energy charge
		  - Summer Peak Period energy charge to the Summer Off-peak energy charge
		  - Non-summer Critical Peak Period energy charge to the non-Summer Off-peak energy charge
		  - Non-summer Peak Period energy charge to the non-Summer Off-peak energy charge
		  - Summer Peak period energy charge to the non-Summer Peak period energy charge.
		• Also indicate how a Critical Peak event day will be determined

	Input Label	Input Explanation
		• Also indicate the proposed duration of the Summer Peak period and the non-Summer Peak period and the days of the week that are to be included in the proposed peak periods.
3.e.	3 Part	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge. • The percent of class revenue requirement less customer charge revenues, to be recovered by demand charges. (The remainder of the revenue requirement will be recovered by energy charges.). • Also indicate how billing demand is to be measured, using the drop-down menu.
3.f.	Seasonal 3 Part	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge. • The percent of class revenue requirement less customer charge revenues, to be recovered by demand charges. (The remainder of the revenue requirement will be recovered by energy charges.) • The ratio of the Summer demand charge to the non-summer demand charge • The ratio of the Summer energy charge to the non-Summer energy charge • Also indicate how billing demand is to be measured, using the drop-down menu.
3.g	3 Part TOU	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge. • The percent of class revenue requirement less customer charge revenues, to be recovered by demand charges. (The remainder of the revenue requirement will be recovered by energy charges.) • The ratio of the Peak demand charge to the Off-peak demand charge • The ratio of the Peak energy charge to the Off-peak energy charge • Also indicate Stakeholder's proposed duration of the Peak period and the days of the week that are to be included in the proposed Peak period • Also indicate how billing demand is to be measured, using the drop-down menu.
3.h	3 Part CPP	For Stakeholder's Delivery Rate Design Proposal, please indicate • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge; • The percent of the class revenue requirement less customer charge revenues to be recovered by demand charges. (The remainder of the revenue requirement will be recovered by energy charges.) • The ratio of the Critical Peak demand charge to the Off-peak demand charge • The ratio of the Peak demand charge to the Off-peak demand charge • The ratio of the Critical Peak energy charge to the Off-peak energy charge • The ratio of the Peak Energy charge to the Off-peak energy charge • Also indicate the conditions that will trigger a Critical Peak event day

	Input Label	Input Explanation
		• Also indicate Stakeholder's proposed duration of the Peak period and the days of the week that are to be included in the proposed peak period • Also indicate how billing demand is to be measured, using the drop-down menu.
3.i	Seasonal 3 Part TOU	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge. • The percent of class revenue requirement less customer charge revenues, to be recovered by demand charges. (The remainder of the revenue requirement will be recovered by energy charges.) • The ratio of the Summer Peak demand charge to the Summer Off-peak demand charge • The ratio of the non-Summer Peak demand charge to the non-Summer Off-peak demand charge • The ratio of the Summer Peak demand charge to the non-Summer Peak demand charge • The ratio of the Summer Peak energy charge to the Summer Off-peak energy charge • The ratio of the non-Summer Peak energy charge to the non-Summer Off-peak energy charge • The ratio of the Summer Peak energy charge to the non-Summer Peak energy charge • Also indicate Stakeholder's proposed duration of the Summer and non-Summer Peak period and the days of the week that are to be included in the proposed peak periods • Also indicate how billing demand is to be measured, using the drop-down menu.
3.j	Seasonal 3 Part CPP	For Stakeholder's Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies' current Customer charge. • The percent of class revenue requirement less customer charge revenues, to be recovered by demand charges. (The remainder of the revenue requirement will be recovered by energy charges.) • The ratio of the Summer Critical Peak demand charge to the Summer Off-peak demand charge • The ratio of the Summer Peak demand charge to the Summer Off-peak demand charge • The ratio of the non-Summer Critical Peak demand charge to the Non-Summer Off-peak demand charge • The ratio of the non-Summer Peak demand charge to the Non-Summer Off-peak demand charge • The ratio of the Summer Peak demand charge to the non-Summer Peak demand charge • The ratio of the Summer Critical Peak energy charge to the Summer Off-peak energy charge

	Input Label	Input Explanation
		• The ratio of the Summer Peak energy charge to the Summer Off-peak energy charge • The ratio of the non-Summer Critical Peak energy charge to the non-Summer Off-peak energy charge • The ratio of the non-Summer Peak energy charge to the non-Summer Off-peak energy charge • The ratio of the Summer Peak energy charge to the non-Summer Peak energy charge • Also indicate Stakeholder’s proposed conditions that will trigger a Critical Peak event day and • Also indicate Stakeholder’s proposed duration of the Summer and non-Summer Peak period and the days of the week that are to be included in the proposed peak period • Also indicate how billing demand is to be measured, using the drop-down menu.
3.k	2 Part Demand Rates (Standby)	For Stakeholder’s Delivery Rate Design Proposal, please indicate: • The proposed Customer charge, expressed as a percent of the Companies’ current Customer charge. • The proposed measure of Contract demand and As-used demand, using the drop-down menus • The proposed Contract Demand charge and As-used Demand charge, each as percentages of unit MCOS or ECOS
3.l	Fixed Subscription Fees	For Stakeholder’s Delivery Rate Design Proposal, please indicate: • The proposed subscription demand measure • Min and Max kW for each kW usage range subscription level • $ Charge per kW for each kW usage range subscription level • Description of basis for resetting subscription levels • Description of any additional charge for excess kW in excess of subscription level.
3.m	Grid Access Charge	For Stakeholder’s Delivery Rate Design Proposal, please indicate: • The proposed basis for billed quantity (e.g. invertor rating, measured maximum export) • $ per kW charge • Definition of applicable technologies. • Description of method for determining level of per unit charge.
3.n	Minimum Bills	For Stakeholder’s Delivery Rate Design Proposal, please indicate: • The proposed minimum $ Bill Amount and minimum kWh and kW amounts. • Description of method for calculating the minimum $ bill amount. • Description of method for calculating the minimum kWh and kW billing quantities. • The Stakeholder’s companion delivery rate design proposal (using the drop-down menu) to be evaluated together with this minimum bill delivery rate design proposal.
3.o	4 Part	For Stakeholder’s Delivery Rate Design Proposal, please indicate:

	Input Label	Input Explanation
		• The proposed Customer charge, expressed as a percent of the Companies' current Customer charge. • The proposed per kWh Energy charge, expressed as a percent of the Companies' current Energy charge. • Also indicate the percent of the remaining revenue requirement[5] to be recovered from the Demand charges for Demand Charge 1 (measured as customer non-coincident peak demand) • Also indicate how customer CP and NCP billing demand is to be measured, using the drop-down menu.

D. Tab 4: Supply Cost Recovery Approaches

The Supply Rate Design Tab is designed to collect information and guidance on Stakeholders' proposed cost recovery approach for Residential and Small Commercial Non-Demand service classifications. The information requested in the Tab 4 Supply sheet is explained in Table 5, below.

Table 5 Tab 4 Input Details

	Input Label	Input Explanation
4.a.	Monthly supply pricing, all kWh	For Stakeholder's Supply Rate Design Proposal, please indicate: • The proposed approach for recovering Installed Capacity ("ICAP") costs
4.b.	Monthly Peak, Off-Peak supply pricing	For Stakeholder's Supply Rate Design Proposal, please indicate: • The proposed approach for recovering Installed Capacity ("ICAP") costs • The proposed duration of the week day Peak period for summer and non-summer months.[6]
4.c	Monthly Critical Peak, Peak, Off Peak supply pricing	For Stakeholder's Supply Rate Design Proposal, please indicate: • The proposed approach for recovering Installed Capacity ("ICAP") costs • The proposed approach for determining Critical Peak event days. • The proposed duration of the Peak periods for summer and non-summer months and the days of the week that are to be included in the proposed peak period
4.d	Market Based Pricing=	For Stakeholder's Supply Rate Design Proposal, please indicate: • The proposed approach for recovering Installed Capacity ("ICAP") costs

[5] The remaining revenue requirement is the total revenue requirement, less revenues from the (i) Customer charge, and (ii) Energy charges.

[6] Stakeholders should carefully consider whether Delivery and Commodity TOU periods should be identical. Rate designs with different Delivery and Commodity TOU periods may be inconsistent with the Commission's Rate Design Principle of customer-orientation ("The customer experience should be practical, understandable, and promote customer choice"). Rate designs with identical Delivery and Commodity TOU periods may be inconsistent with the Commission's Rate Design Principle of cost causation.

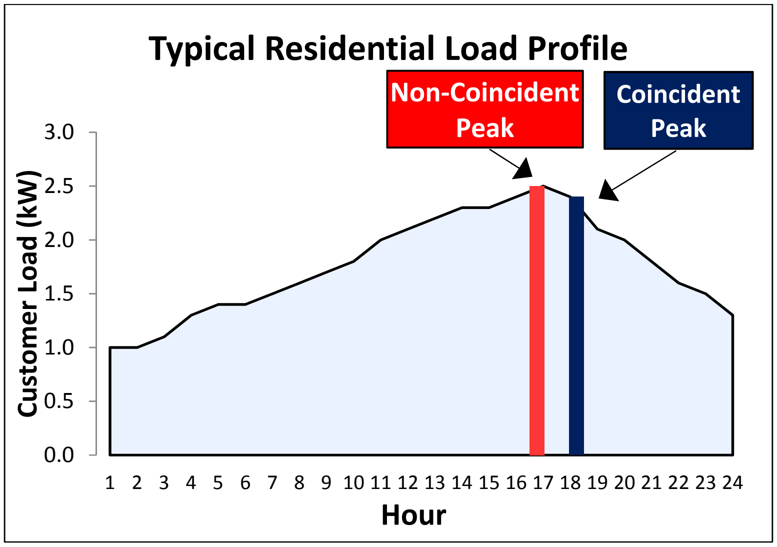
III. Reference Data

A. Fundamentals of Rate Design[7]

1. Introduction

These “Rate Design Fundamentals” explain and illustrate the Rate Design Parameters that are included in the Rate Design Input worksheet, Sheet 3 (Delivery), Sections 3a - 3o; the rate design fundamentals also explain and illustrate the Rate Design parameters that are included in Sheet 4 (Commodity), Sections 4a – 4d

2. Demand Charges: Delivery Service (Non-coincident (NCP) and Coincident Peak (CP))

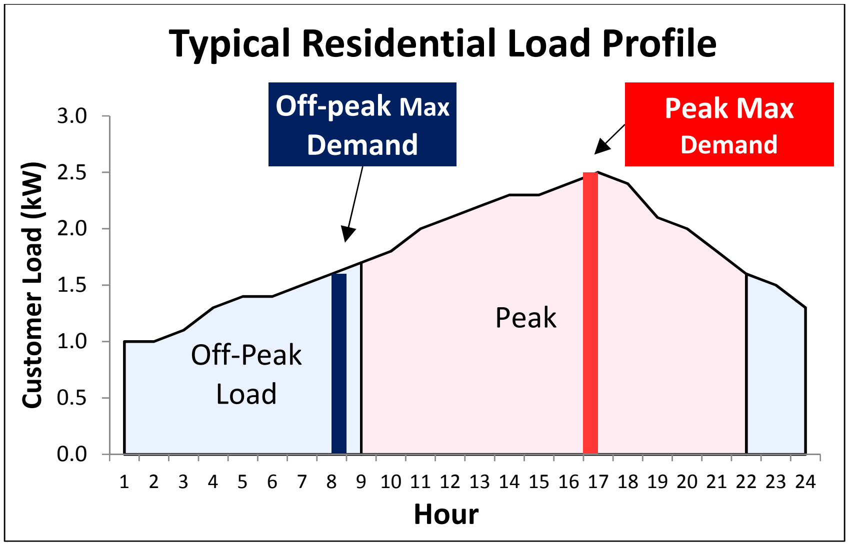


Rate Design Considerations	Rate Design Decisions
• T&D Capacity-related Cost-causation: - Non-coincident Peak demand affects distribution capacity close to individual customers - Coincident Peak demand affects distribution capacity further from the customer o But billing Mass Market classes on Coincident Peak is challenging: Time of Coincident Peak is not known until the end of the month • Rate structures that charge for Coincident Peak demand require AMI or interval meters and revisions to billing systems and processes • Using longer intervals to measure billing demand “smooths over” short-duration fluctuations in load (spikes)	There are several decisions concerning the measurement of Billing Demand: • Demand can be measured at time of: - Non-coincident Peak - Coincident Peak - Non-coincident Peak is most common measure of demand; o Coincident Peak is used for SCs with small number of very large sophisticated customers • Demand is measured in intervals – can be, e.g., 15, 30, or 60 minutes • Demand can be measured as average of customer’s top 1 to 5 maximum demands in the month • Billing demand can be measured as kW or kVA; kVa accounts for reactive power. Or, reactive

[7] The charts and text in this section were included in the February 8, 2018 VDER Rate Design Working Group Joint Utilities Presentation.

Rate Design Considerations	Rate Design Decisions
• Using averages of top peak demand to measure billing demand "smooths over" longer-duration fluctuations in load.	power can also be accounted for by measuring kVAR • Billing demand can be measured separately for Peak and Off-Peak periods.

3. Time of Use (TOU)

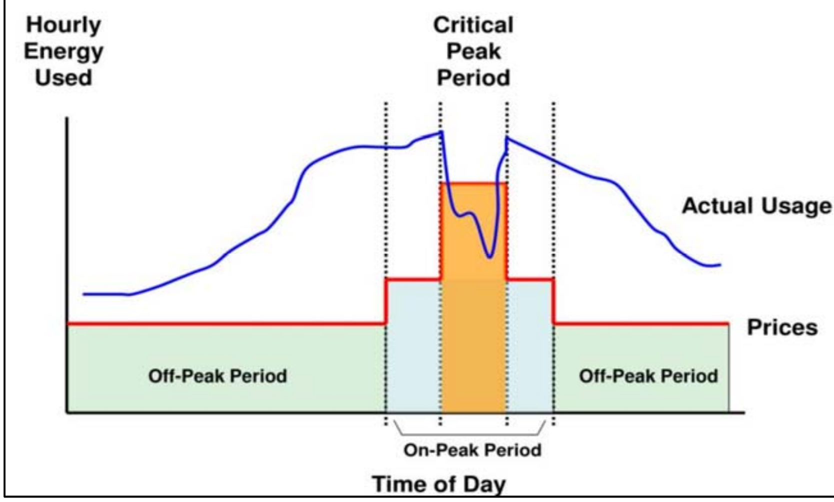


Rate Design Considerations	Rate Design Decisions

• TOU periods are determined based on analysis of hourly loads for one or more years
• Peak period(s) are defined to separate high load / high cost hours from remaining hours.
  - TOU periods may be determined separately for “Summer” and “Non-Summer” seasons
• In setting the TOU parameters (e.g., Peak period hours and rates), care must be taken to avoid shifting the maximum demand in a few years to the Off-peak period, due to customer responsiveness.
• Rate structures that include TOU demand require TOU meters, interval meters or AMI, and revisions to billing systems and processes.
	• Off-peak period is generally defined as: nights, weekends, and holidays
	• Typical Peak period parameters:
	  - Duration of Peak period
	  - Start time / end time
	• Three Period distribution rate structures introduce a shoulder periods

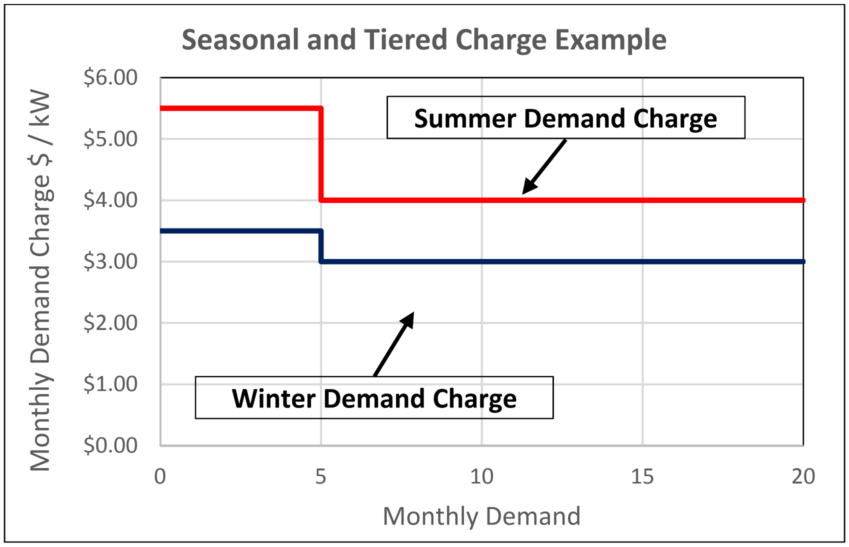
4. Critical Peak Pricing

Critical Peak Pricing Example



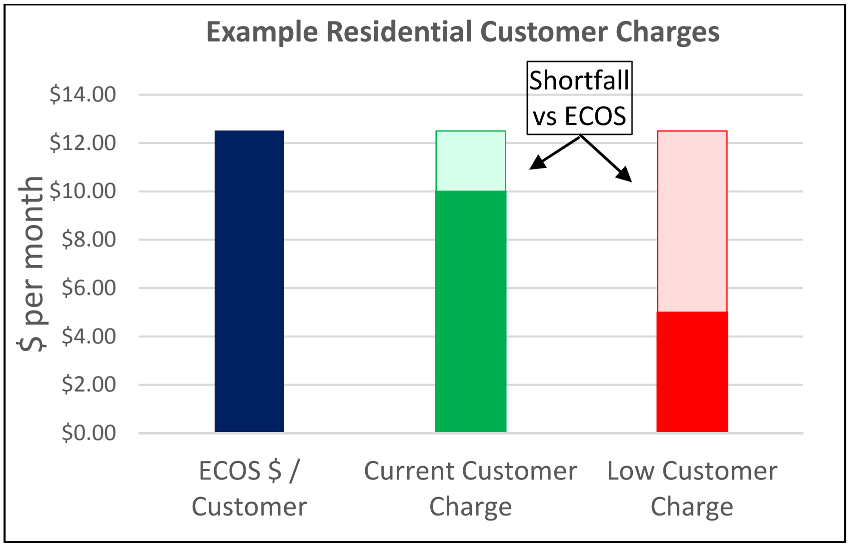
Rate Design Considerations	Rate Design Decisions
• Critical peak pricing (CPP): - The utility declares a CPP event when high Wholesale market (NYISO) prices and / or high delivery system loads are expected - High prices are charged on Event Day for the specified Critical Peak time period - Event days are declared when pre-specified conditions are met; expected number of event days may be 10 – 20 • Typically, a two-part TOU rate structure applies on all days other than Critical Peak Event days. - Decisions on Commodity TOU periods are similar to decisions on Delivery TOU periods	• Determine whether CPP charge is a demand charge or kWh usage charge. • Determine magnitude of the CPP charge - Constant charge for all events - Charge that varies by event (also known as variable peak pricing (VPP). • Event day Notification options: • Day ahead or Short notice – e.g., 4 hours • CPP period options: - Set duration for all Event days (e.g., 5 hours) or vary (e.g., 1 – 5 hours) - Hours of potential CPP periods could be set (e.g., CPP between 1 pm and 8 pm) • CPP Peak and Off-peak rates would be lower than two-part TOU Peak and Off-Peak rates (CPP pricing is revenue neutral) • CPP has been offered both as an opt-in or opt-out option • Any true up mechanism to address differences in events called and event assumptions used in rate design.

5. Seasonal / Tiered pricing



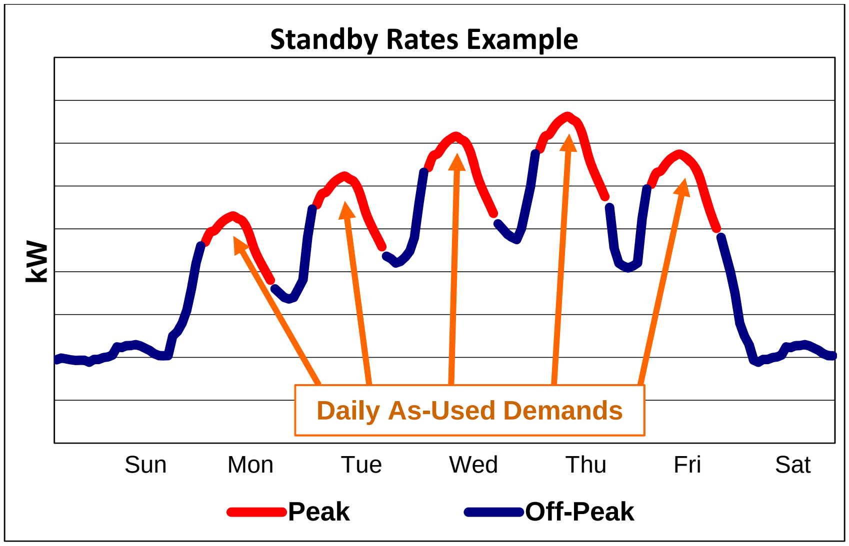
Rate Design Considerations	Rate Design Decisions
• Seasonal rates generally reflect seasonal differences in cost and demand - Commodity and / or Delivery rates are higher in the high demand season. • In tiered rate structures the rates per kWh or kW can increase or decrease with monthly usage.	• For seasonal pricing, the seasonal differential must be determined. • For tiered pricing, rate design must determine (a) number of blocks; (b) kW or kWh breakpoints for each block and (c) rate for each block • Tiered Pricing: - A customer's charge per kW or kWh changes as the customer's monthly demand or usage increases - Rate design decisions: o Tiers (blocks) of demand or usage o Rate to be charged for each block ▪ Alternative block structures: Declining or Inclining (Inverted)

6. Reduced or Increased Customer Charges



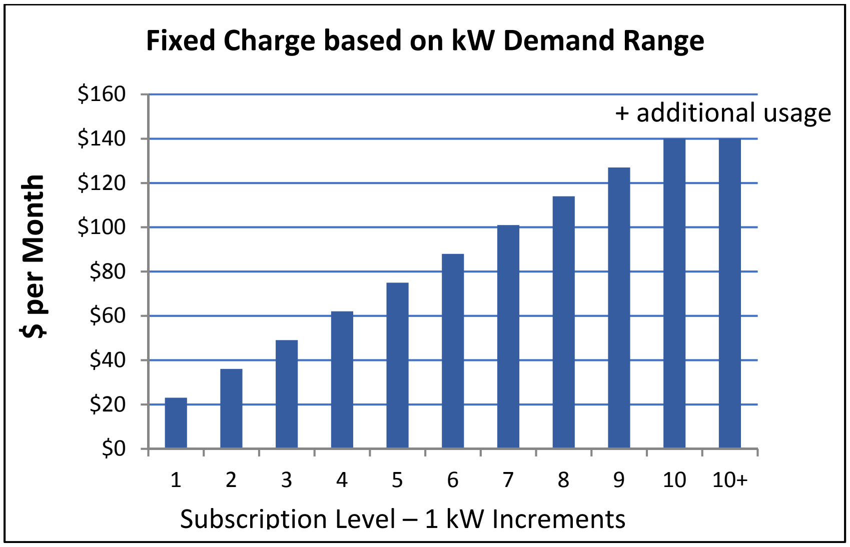
Rate Design Considerations	Rate Design Decisions
Fixed monthly charge associated with the presence of a customer on the utility system	• Common arguments for increasing customer charge, compared to current rates: - ECOS typically indicates that customer charges are significantly less cost - Higher customer charge would: o Reduce subsidization of low use customers by high use customers in class o Reduce cost shifting to DER non-participants • Common arguments for decreasing customer charge, compared to current rates: - Higher kWh and kW charges resulting from lower customer charges incent energy efficient behavior and investments - Higher kWh charges may encourage desired market and policy outcomes including energy efficiency and peak load reduction

7. Standby Rates



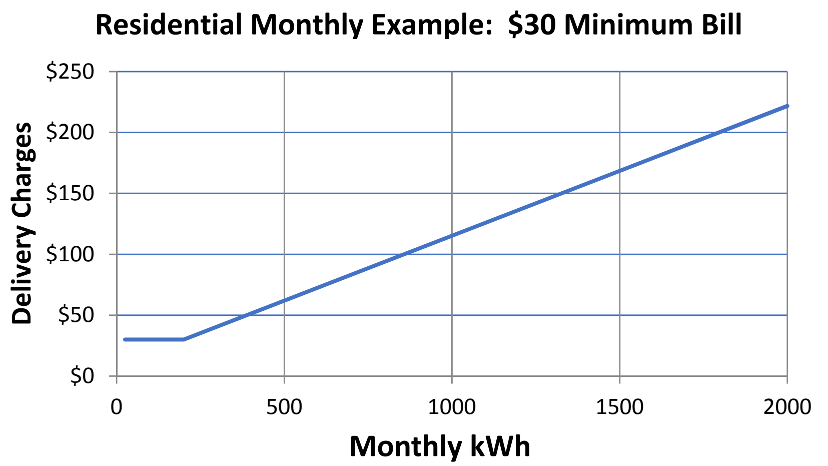
Rate Design Considerations	Rate Design Decisions
• Customer Charges recover full customer costs. • Contract Demand Charges recover the costs of “local” facilities. • Daily As-Used Demand Charges recover the costs of “shared” facilities. • No delivery charges assessed on a per kWh basis.	• Determination of costs to be included in contract demand charges vs daily as-used demand charges • Measurement of as-used demands: - Demand interval - Number of measurements/averaging - Time period for measurement - Need to address actual demands that exceed contract demand level: - Additional charge for excess kW - Reset contract demand

8. Subscription Service



Rate Design Considerations	Rate Design Decisions
• Fixed delivery charge based on kW usage range (measured using annual peak demand) • Charge does not vary with kWh usage • Single charge includes customer and other delivery costs • Favors customers with high annual load factor	• Determination of kW usage ranges • Determination of individual customer subscription kW levels - Customer choice (any minimum) - Default level based on history • Measurement of actual demands: - Demand interval - Number of measurements/averaging - Time period for measurement - Need to address actual demands that exceed subscription level: - Additional charge for excess kW - Reset subscription

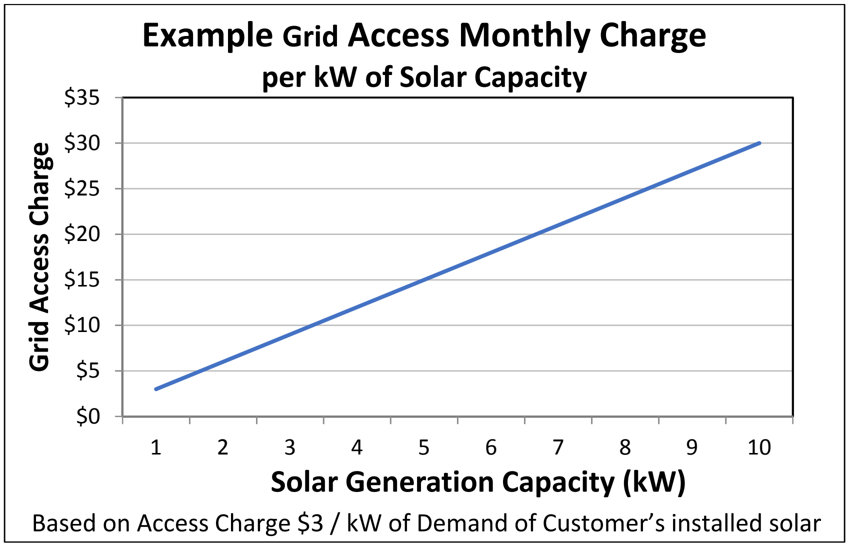
9. Minimum Bill



Based on minimum bill of $30 for 0 to 200 kWh and volumetric rate of $0.10654 / kWh for consumption in excess of 200 kWh/month.

Rate Design Considerations	Rate Design Decisions
• Fixed charge for customer-related costs and a minimum level of kWh or kW consumption • Ensures that each customer makes some minimum contribution to the recovery of utility costs regardless of consumption • Some customers may be adversely affected if they use less than the minimum consumption amount	• Minimum bill amount must be determined. • Minimum consumption amount must be determined. • Can also be set as a minimum dollar amount, regardless of consumption

10. Grid Access Charge



Rate Design Considerations	Rate Design Decisions
• Charge per kW of solar generating capacity • Ensures that solar customers contribute to the recovery of utility costs regardless of net monthly energy consumption. • Technology-specific mechanism. • May not be appropriate for non-solar technologies.	• Determine level of per unit charge. • Determine basis for individual customer's charge - Inverter rating - Measured maximum

B. JU ECOS Approach and Results

1. Introduction

Embedded Cost of Service Studies involve the steps of Functionalization, Classification, and Allocation.
"Functionalization" refers to categorizing plant investment costs and operating expenses by the operational functions that are associated with the categories of plant and expense, e.g., Production, or Distribution.
"Classification" refers to categorizing the functionalized cost elements according to factors of utilization that match cost causation, e.g. customer, demand, and energy. Specifically, (a) Customer costs are associated with the presence of a customer on the system; these costs do not vary with usage; (b) Demand costs are incurred to meet demand requirements that customers place on the system and (c) Energy costs vary in relation to the amount of electricity consumed by customers. Except for purchased power and fuel, almost all electric utility costs do not vary with energy usage; very little of a distribution service cost structure is energy-related.
"Allocation" refers to assigning the functionalized and classified plant and expenses to service classifications according to factors that best reflect responsibility for the costs, by FERC account. For example, customer-related costs may be allocated according to the number of customers, or number of bills; demand-related costs may be allocated according to measures of demand (Non-coincident peak demand, coincident peak demand).

2. Residential ECOS Approach and Results

a. Consolidated Edison

	Classification			Class Allocation Methodology		Residential Allocation (millions)		
	Demand	Customer	Methodology	Demand	Customer	Demand	Customer	Total
Transmission	100%			system peak (kW)		$ 240.0		$ 240.0
Primary Distribution								
Substations	100%			class peaks (kW)		188.6		188.6
Feeders	91%	9%	Minimum System	class peaks (kW)	same as secon. cust.	335.4	58.0	393.4
Secondary Distribution								-
OH Lines	85%	15%	Minimum System	blend of class peaks and individual customer max demands	study of # of overhead and underground service connections by class	33.0	14.0	47.0
UG Lines	79%	21%	Minimum System			301.0	103.0	404.0
OH Transformers	54%	46%	Minimum System			12.0	26.0	38.0
UG Transformers	61%	39%	Minimum System			99.0	81.0	180.0
Services		100%			study of cost of services by class		149.0	149.0
Meters		100%			study of # and cost of meters by class		109.0	109.0
Customer Accounting		100%			# of customers		173.0	173.0
Customer Service		100%			# of customers		31.0	31.0
						$1,209.0	$ 744.0	$1,953.0

b. Orange and Rockland

	Classification			Class Allocation Methodology		Residential Allocation (millions)		
	Demand	Customer	Methodology	Demand	Customer	Demand	Customer	Total
Transmission	100%			system peak (kW)		$ 29.0		$ 29.0
Prim Dist								
Substations	100%			class peaks (kW)		16.0		16.0
Feeders	95%	5%	Minimum System	class peaks (kW)	same as secon. cust.	50.0	4.0	54.0
Sec Dist								
OH Lines	88%	12%	Minimum System	avg. of class peaks and individual cust. max demands	study of # of overhead and underground service connections by class	24.0	4.0	28.0
UG Lines	35%	65%	Minimum System			1.0	1.0	2.0
OH Transformers	64%	36%	Minimum System			4.0	3.0	7.0
UG Transformers	39%	61%	Minimum System			1.0	3.0	4.0
Services		100%			study of cost of services by class		3.0	3.0
Meters		100%			study of the number and cost of meters by class		14.0	14.0
Customer Accounting		100%			# of customers		17.0	17.0
Customer Service		100%			# of customers		6.0	6.0
						$ 125.0	$ 55.0	$ 180.0

c. National Grid - Niagara Mohawk

	Classification			Class Allocation Methodology		Residential Allocation (millions)[8]		
	Demand	Customer	Methodology	Demand	Customer	Demand	Customer	Total
Transmission	100%			1CP at Transmission		$ 172.2		$172.2
Prim Dist								
Substations	100%	0%		Class NCP at Primary		88.0		88.0
Feeders	50%	50%	JP in Case 12-E-0201	Class NCP at Primary	Customers at Primary	134.5	197.6	332.1
Sec Dist								
OH Lines	41.56%	58.44%	Zero Load Study	Class NCP at Secondary	Customers at Secondary	16.5	39.6	56.1
UG Lines	48.25%	51.75%	Zero Load Study	Class NCP at Secondary	Customers at Secondary	4.2	7.7	12.0
Transformers	100.00%	0.00%		Directly assigned based on customers using each Transformer type		85.9		85.9
Services		100%			Current cost of Services-Residential vs Commercial		63.8	63.8
Meters		100%			Current cost of typical Meter types for each class		20.1	20.1
Customer Accounting		100%			Study of activities in Account 903; each activity is allocated		26.6	26.6
Customer Service		100%			Study of activities in Account 908; each activity is allocated		87.7	87.7
						$ 501.4	$ 443.2	$944.5

[8] Costs exclude deferral sur-credits.

d. New York State Electric & Gas Corporation

	Classification				Class Allocation Methodology			Residential Allocation (millions)			
	Demand	Customer	Energy	Method	Demand	Customer	Energy	Demand	Customer	Energy	Total
Fixed Production											
Hydro			100%				Class usage			$ 8.6	$ 8.6
Other	100%				system peak (2 CP) (kW)			0.2			0.2
Transmission	100%				system peak (12 CP) (kW)			43.1			43.1
Primary Distribution											-
Station Equipment	100%				Class peaks (NCP) (kW)						-
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
Total Prim Distrib								45.1	69.3		114.4
Secondary Distribution											-
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
Total Sec Distrib								7.0	10.5		17.5
Line Transformers	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs		7.9	13.7		21.6
Services		100%				# Sec. custs			7.5		7.5
Meters		100%				study #, $ of meters by class			34.3		34.3
Customer Accts & Customer Service		100%				# of custs, # bills			44.4	2.7	47.1
								$ 103.2	$ 179.7	$11.2	$294.2

e. Rochester Gas and Electric Corporation

	Classification				Class Allocation Methodology			Residential Allocation (millions)			
	Demand	Customer	Energy	Method	Demand	Customer	Energy	Demand	Customer	Energy	Total
Fixed Production											
Hydro			100%				Class usage			$16.7	$ 16.7
Other	100%				system peak (2 CP) (kW)			1.0			1.0
Transmission	100%				system peak (12 CP) (kW)			26.8			26.8
Primary Distribution											-
Station Equipment	100%				Class peaks (NCP) (kW)						-
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					-
Total Prim Distrib								33.2	44.4		77.6
Secondary Distribution											-
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					-
Total Sec Distrib								5.4	7.7		13.2
Line Transformers	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs		3.4	5.8		9.2
Services		100%				# Sec. custs			3.4		3.4
Meters		100%				study #, $ of meters by class			11.7		11.7
Customer Accts & Customer Service		100%				# of custs, # bills			32.8	(0.4)	32.4
								$ 69.9	$ 105.8	$16.2	$191.9

f. Central Hudson Gas & Electric Corporation

	Classification				Class Allocation Methodology		Residential Allocation (millions)			
	Demand	Customer	Energy	Methodology	Demand	Customer	Demand	Customer	Energy	Total
Production	21%	0%	79%	Energy: hydro; Demand: CTs	summer/winter average CP	avg hourly delivery demand at BUS level	$ 1.3		$ 3.4	$ 4.6
Transmission	100%				most at system peak (kW) - some at summer / winter average CP, NCP		42.6			42.6
Prim Dist										-
Substations	100%				Class NCP at Dist Subs		14.9			14.9
Feeders	28%	72%		Minimum system; conductor cost varies w/ load	Class NCP at Primary	# custs at prim	12.5	43.8		56.3
Total Prim Dist							27.3	43.8		71.1
Second Dist										-
OH Lines	11%	89%		Minimum system; conductor cost varies w/ load	∑ NCP at Secondary	# custs at sec	2.5	10.3		12.8
UG Lines	24%	76%		Minimum system; conductor cost varies w/ load	∑ NCP at Secondary	# custs at sec	3.0	12.6		15.7
Transformers	46%	53%		Minimum Size	Class & ∑ NCP Average	# custs at sec	3.5	4.9		8.4
Total Secon Dist							9.0	27.9		36.9
Services	64%	36%		Cust: labor unit cost x avg ft.	∑ NCP at Secondary	# of service drops	2.7	1.4		4.1
Installs on Cust Premises	0%	100%				plant study		4.8		4.8
Meters		100%				study of # and $ of meters by class		5.4		5.4
Cust Acctng		100%				study of activities		27.6		27.6
Cust Service		100%				study of activities		9.7		9.7
							$ 82.9	$ 120.6	$ 3.4	$206.9

3. Small Commercial Non-Demand ECOS Approach and Results

a. Consolidated Edison

	Classification			Class Allocation Methodology		Small Commercial Non-Demand Allocation (millions)		
	Demand	Customer	Methodology	Demand	Customer	Demand	Customer	Total
Transmission	100%			system peak (kW)		$39.0		$39.0
Primary Distribution								$-
Substations	100%			class peaks (kW)		25.5		$25.5
Feeders	91%	9%	Minimum System	class peaks (kW)	same as secon. cust.	45.0	13.0	$58.0
Secondary Distribution								$-
OH Lines	85%	15%	Minimum System	blend of class peaks and individual customer max demands	study of # of overhead and underground service connections by class	5.0	0.8	$5.8
UG Lines	79%	21%	Minimum System			48.0	30.0	$78.0
OH Transformers	54%	46%	Minimum System			2.0	1.0	$3.0
UG Transformers	61%	39%	Minimum System			16.0	24.0	$40.0
Services		100%			study of cost of services by class		47.0	$47.0
Meters		100%			study of # and cost of meters by class		19.0	$19.0
Customer Accounting		100%			# of customers		18.0	$18.0
Customer Service		100%			# of customers		4.0	$4.0
						$180.5	$156.8	$337.3

b. Orange and Rockland

	Classification			Class Allocation Methodology		Small Commercial Non-Demand Allocation (millions)		
	Demand	Customer	Methodology	Demand	Customer	Demand	Customer	Total
Transmission	100%			system peak (kW)		$0.2		$0.2
Prim Dist								$-
Substations	100%			class peaks (kW)		0.2		$0.2
Feeders	95%	5%	Minimum System	class peaks (kW)	same as secon. cust.	0.4	0.1	$0.5
Sec Dist								$-
OH Lines	88%	12%	Minimum System	avg. of class peaks and individual cust. max demands	study of # of overhead and underground service connections by class	0.2	0.1	$0.3
UG Lines	35%	65%	Minimum System			0.004	0.1	$0.1
OH Transformers	64%	36%	Minimum System			0.05	0.1	$0.1
UG Transformers	39%	61%	Minimum System			0.02	0.2	$0.2
Services		100%			study of cost of services by class		0.1	$0.1
Meters		100%			study of the number and cost of meters by class		0.2	$0.2
Customer Accounting		100%			# of customers		0.4	$0.4
Customer Service		100%			# of customers		0.2	$0.2
						$1.1	$1.4	$2.5

c. National Grid - Niagara Mohawk

	Classification			Class Allocation Methodology		Small Commercial Non-Demand Allocation (millions)[9]		
	Demand	Customer	Methodology	Demand	Customer	Demand	Customer	Total
Transmission	100%			1CP at Transmission		$10.4		10.4
Prim Dist								
Substations	100%	0%		Class NCP at Primary		5.1		5.1
Feeders	50%	50%	JP in Case 12-E-0201	Class NCP at Primary	Customers at Primary	7.7	14.7	22.5
Sec Dist								
OH Lines	41.56%	58.44%	Zero Load Study	Class NCP at Secondary	Customers at Secondary	1.0	3.7	4.6
UG Lines	48.25%	51.75%	Zero Load Study	Class NCP at Secondary	Customers at Secondary	0.2	0.7	1.0
Transformers	100.00%	0.00%		Directly assigned based on customers using each Transformer type		5.0		5.0
Services		100%			Current cost of Services-Residential vs Commercial		5.9	5.9
Meters		100%			Current cost of typical Meter types for each class		2.0	2.0
Customer Accounting		100%			Study of activities in Account 903; each activity is allocated		2.6	2.6
Customer Service		100%			Study of activities in Account 908; each activity is allocated		8.5	8.5
						$29.4	$38.1	$67.4

[9] Costs exclude deferral sur-credits.

d. New York State Electric & Gas Corporation

	Classification				Class Allocation Methodology			Small Commercial Non-Demand Allocation (millions)			
	Demand	Customer	Energy	Method	Demand	Customer	Energy	Demand	Customer	Energy	Total
Fixed Production											
Hydro			100%				Class usage			$0.2	$0.2
Other	100%				system peak (2 CP) (kW)			0.01			0.01
Transmission	100%				system peak (12 CP) (kW)			2.2			2.2
Primary Distribution											
Station Equipment	100%				Class peaks (NCP) (kW)						
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
Total Prim Distrib								2.5	6.5		9.0
Secondary Distribution											
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
Total Sec Distrib								0.4	1.0		1.4
Line Transformers	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs		0.4	1.3		1.7
Services		100%				# Sec. custs			0.7		0.7
Meters		100%				study #, $ of meters by class			5.0		5.0
Customer Accts & Customer Service		100%				# of custs, # bills			3.3	0.3	3.6
								$5.5	$17.8	$0.5	$23.8

e. Rochester Gas and Electric Corporation

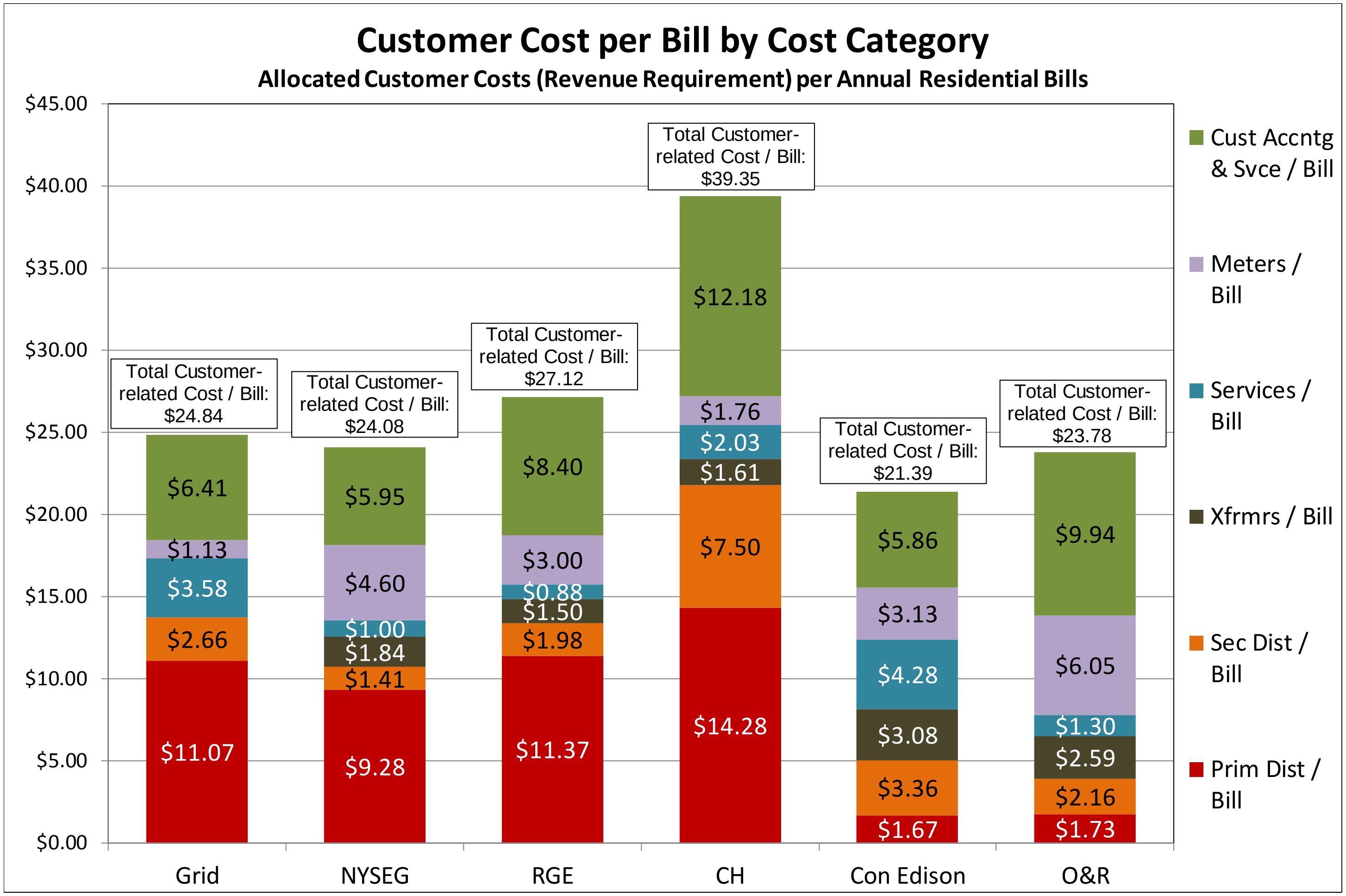
	Classification				Class Allocation Methodology			Small Commercial Non-Demand Allocation (millions)			
	Demand	Customer	Energy	Method	Demand	Customer	Energy	Demand	Customer	Energy	Total
Fixed Production											
Hydro			100%				Class usage			$1.0	$1.0
Other	100%				system peak (2 CP) (kW)			0.1			0.1
Transmission	100%				system peak (12 CP) (kW)			2.1			2.1
Primary Distribution											
Station Equipment	100%				Class peaks (NCP) (kW)						
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Prim. custs					
Total Prim Distrib								2.6	3.3		6.0
Secondary Distribution											
Poles, Towers, Fixtures	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
OH Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
UG Conduit	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
UG Conductors	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs					
Total Sec Distrib								0.4	0.6		1.0
Line Transformers	50%	50%		Settlement	Class peaks (NCP) (kW)	# Sec. custs		0.3	0.4		0.7
Services		100%				# Sec. custs			0.3		0.3
Meters		100%				study #, $ of meters by class			1.2		1.2
Customer Accts & Customer Service		100%				# of custs, # bills			1.7	0.0	1.7
								$5.5	$7.5	$1.0	$14.0

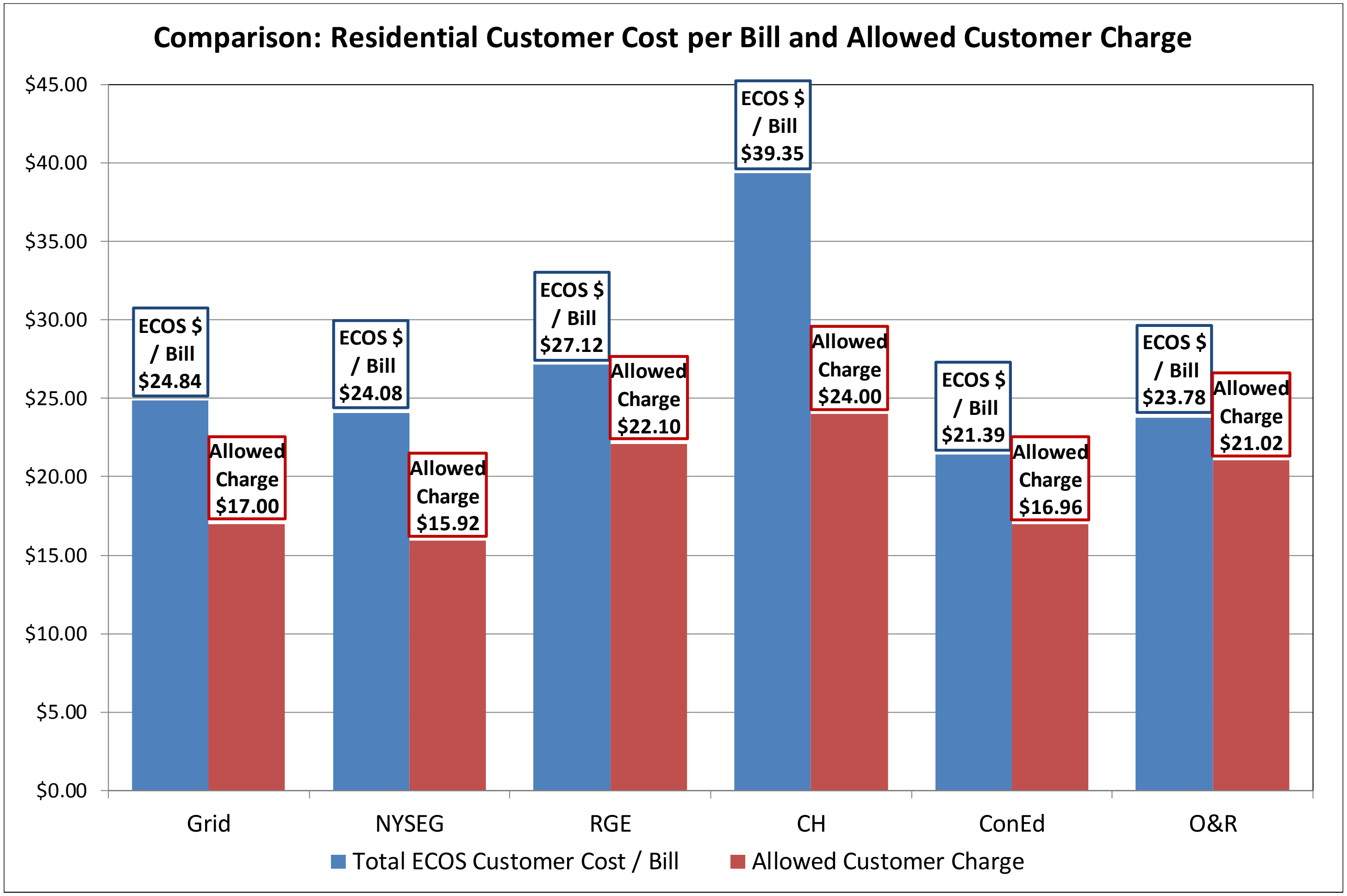
f. Central Hudson Gas & Electric Corporation

	Classification				Class Allocation Methodology		Small Commercial Non-Demand Allocation (millions)			
	Demand	Customer	Energy	Methodology	Demand	Customer	Demand	Customer	Energy	Total
Production	21%	0%	79%	Energy: hydro; Demand: CTs	summer/winter average CP	avg hourly delivery demand at BUS level	$0.1		$0.2	$0.3
Transmission	100%				most at system peak (kW) - some at summer / winter average CP, NCP		1.8			1.8
Prim Dist										-
Substations	100%				Class NCP at Dist Subs		1.4			1.4
Feeders	28%	72%		Minimum system; conductor cost varies w/ load	Class NCP at Primary	# custs at prim	1.2	3.8		5.0
Total Prim Dist							2.6	3.8		6.4
Second Dist										-
OH Lines	11%	89%		Minimum system; conductor cost varies w/ load	∑ NCP at Secondary	# custs at sec	0.2	0.9		1.1
UG Lines	24%	76%		Minimum system; conductor cost varies w/ load	∑ NCP at Secondary	# custs at sec	0.2	1.1		1.3
Transformers	46%	53%		Minimum Size	Class & ∑ NCP Average	# custs at sec	0.3	0.4		0.7
Total Secon Dist							0.6	2.4		3.0
Services	64%	36%		Cust: labor unit cost x avg ft.	∑ NCP at Secondary	# of service drops	0.2	0.1		0.3
Installs on Cust Premises	0%	100%				plant study		0.4		0.4
Meters		100%				study of # and $ of meters by class		0.8		0.8
Cust Acctng		100%				study of activities		3.2		3.2
Cust Service		100%				study of activities		0.6		0.6
							$5.2	$11.5	$0.2	$17.0

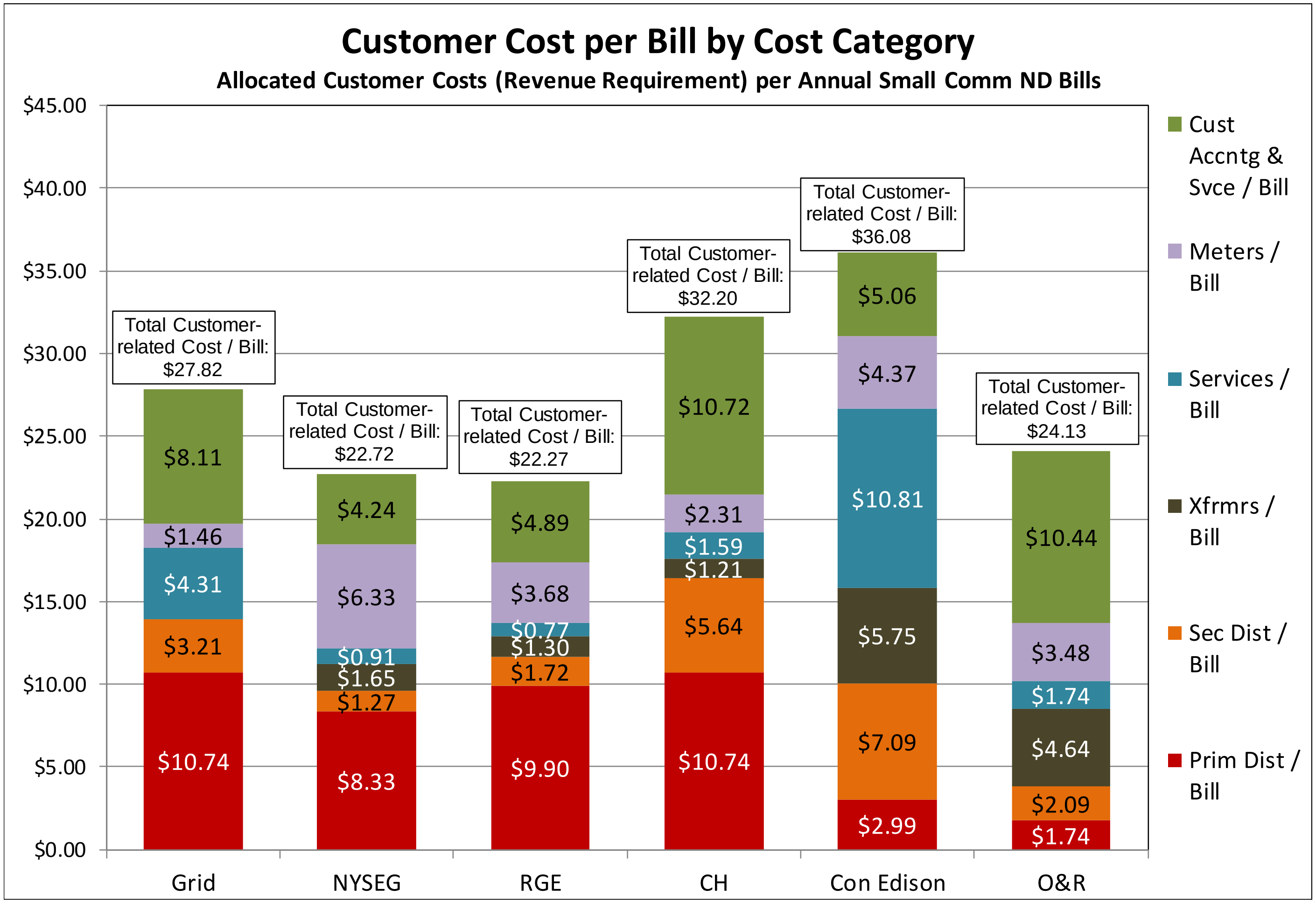
C. JU ECOS Summary Charts

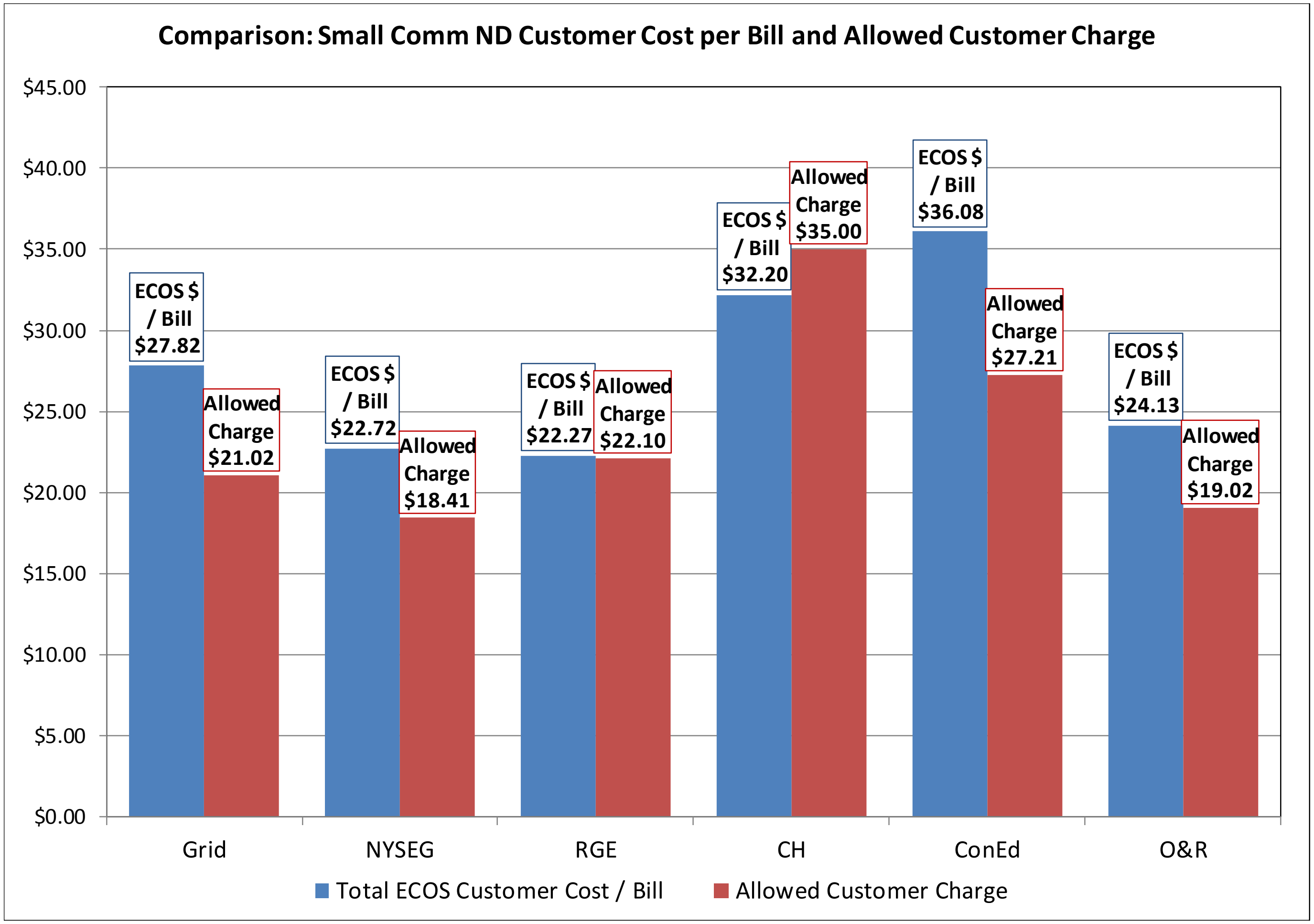
1. Residential




Comparison: Residential Customer Cost per Bill and Allowed Customer Charge
$45.00
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
ECOS $ / Bill $24.84
Allowed Charge $17.00
ECOS $ / Bill $24.08
Allowed Charge $15.92
ECOS $ / Bill $27.12
Allowed Charge $22.10
ECOS $ / Bill $39.35
Allowed Charge $24.00
ECOS $ / Bill $21.39
Allowed Charge $16.96
ECOS $ / Bill $23.78
Allowed Charge $21.02
Grid
NYSEG
RGE
CH
ConEd
O&R
Total ECOS Customer Cost / Bill
Allowed Customer Charge

2. Small Commercial Non-Demand





Comparison: Small Comm ND Customer Cost per Bill and Allowed Customer Charge
$45.00
$40.00
$35.00
$30.00
$25.00
$20.00
$15.00
$10.00
$5.00
$0.00
ECOS $ / Bill $27.82
Allowed Charge $21.02
ECOS $ / Bill $22.72
Allowed Charge $18.41
ECOS $ / Bill $22.27
Allowed Charge $22.10
ECOS $ / Bill $32.20
Allowed Charge $35.00
ECOS $ / Bill $36.08
Allowed Charge $27.21
ECOS $ / Bill $24.13
Allowed Charge $19.02
Grid
NYSEG
RGE
CH
ConEd
O&R
Total ECOS Customer Cost / Bill
Allowed Customer Charge

D. Current Mass Market Rates

1. Residential

		Central Hudson[10]	Consolidated Edison[11]	Orange and Rockland[12]	Niagara Mohawk[13]	New York State Electric & Gas[14]	Rochester Gas and Electric[15]
Customer charge		$24.00	$15.76	$20.00	$17.00	$15.11	$21.38
Bill Issuance Fee			$1.20	$1.02		$0.81	$0.72
Total		$24.00	$16.96	$21.02	$17.00	$15.92	$22.10
Delivery Charges							
Energy charge per kWh							
Summer[16]	1st 250 kWh	$0.06586	$0.10221	$0.07296	$0.05044	$0.04256	$0.04645
Summer	Over 250 kWh	$0.06586	$0.11749	$0.08743	$0.05044	$0.04256	$0.04645
Non-Summer[17]	1st 250 kWh	$0.06586	$0.10221	$0.07296	$0.05044	$0.04256	$0.04645
Non-Summer	Over 250 kWh	$0.06586	$0.10221	$0.07296	$0.05044	$0.04256	$0.04645

10 PSC NO: 15 Electricity, Leaf: 165; Initial Effective Date: 07/01/16

11 PSC NO: 10 – Electricity, Leaf: 388 Initial Effective Date: 01/01/2018

12 PSC. NO. 3 Electricity, Leaf: 264 Initial Effective Date: November 1, 2016

13 PSC NO: 220 Electricity, Leaf: 349 Initial Effective Date: April 1, 2018

14 PSC No: 120 – Electricity, Leaf No. 119 Initial Effective Date: August 12, 2016

15 PSC No: 19 - Electricity Leaf No. 161.1 Initial Effective Date: August 12, 2016

16 The months of June, July, August, and September

17 All other months

2. **Small Commercial Non-Demand**

		Central Hudson[18]	Consolidated Edison[19]	Orange and Rockland[20]	Niagara Mohawk[21]	New York State Electric & Gas[22]	Rochester Gas and Electric[23]
Service Classification		SC 2 ND	SC 2	SC 2	SC	SC 6	SC 2
Customer charge		$35.00			$21.02	$17.60	$21.38
Metered			$26.01	$18.00			
Unmetered			$21.60	$17.00			
Bill Issuance Fee			$1.20	$1.02		$0.81	$0.72
Total		$35.00			$21.02	$18.41	$22.10
Metered			$27.21	$19.02			
Unmetered			$22.80	$18.02			
Delivery Charges							
Energy charge per kWh							
Summer[24]		$0.02702	$0.1246	$0.06764	$ 0.05567	$0.04746	$0.03712
Non-Summer[25]		$0.02702	$0.1046	$0.04999	$ 0.05567	$0.04746	$0.03712

18 PSC NO: 15 Electricity, Leaf: 169; Initial Effective Date: 07/01/16

19 PSC NO: 10 – Electricity, Leaf: 397 Initial Effective Date: 01/01/2018

20 PSC. NO. 3 Electricity, Leaf: 269 Initial Effective Date: November 1, 2016

21 PSC NO: 220 Electricity, Leaf: 349 Initial Effective Date: April 1, 2018

22 PSC No: 120 – Electricity, Leaf No. 203 Initial Effective Date: August 12, 2016

23 PSC No: 19 - Electricity Leaf No. 164 Initial Effective Date: August 12, 2016

24 The months of June, July, August, and September

25 All other months

E. JU Current Billing determinants

1. Residential SC-1

		Central Hudson[26]	Consolidated Edison[27]	Orange and Rockland[28]	Niagara Mohawk[29]	New York State Electric & Gas[30]	Rochester Gas and Electric[31]
Customer Bills		3,066,066	34,761,707	2,312,970	17,840,790	7,670,676	3,999,027
kWh Energy		2,024,967,993	14,080,401,003	1,591,132,070	11,326,831,683	5,029,733,266	2,721,656,690
Summer[32]	1st 250 kWh		2,552,739,086	179,242,750			
Summer	Over 250 kWh		3,352,743,184	471,370,241			
Summer	All kWh		5,905,482,270	650,612,991			
Non-Summer[33]	1st 250 kWh		4,626,338,452	349,045,806			
Non-Summer	Over 250 kWh		3,548,580,281	591,473,273			
Non-Summer	All kWh		8,174,918,733	940,519,079			

26 P.S.C. No. 15 – Electricity – 14th Revised Leaf No. 165.
27 Billing Determinants used to develop ECOS Study filed in Case 16-E-0060.
28 Billing Determinants used to develop ECOS Study filed in Case 18-E-0067.
29 Billing determinants used to develop ECOS study filed in Case 17-E-0238.
30 Billing Determinants used in Case 15-E-0283 et. al.
31 Billing Determinants used in Case 15-E-0283 et. al.
32 The months of June, July, August, and September
33 All other months

2. Small Commercial Non-Demand

		Central Hudson[34]	Consolidated Edison[35]	Orange and Rockland[36]	Niagara Mohawk[37]	New York State Electric & Gas[38]	Rochester Gas and Electric[39]
Rate		SC 2 ND	SC 2	SC 2	SC 2 ND	SC 6	SC 2
Customer Bills		357,660	4,306,623	57,483	1,369,286	819,639	343,831
Metered				26,477			
Unmetered				31,006			
kWh Energy		164,051,999	2,152,203,577	16,377,381	614,715,129	272,618,794	220,947,556
Summer[40]	1st 2,000 kWh		698,594,781				
Summer	Over 2,000 kWh		62,352,298				
Summer	All kWh		760,947,079	5,328,027			
Non-Summer[41]	1st 2,000 kWh		1,277,253,550				
Non-Summer	Over 2,000 kWh		114,002,948				
Non-Summer	All kWh		1,391,256,498	11,049,354			

34 P.S.C. No. 15 – Electricity – 17th Revised Leaf No. 169.
35 Billing Determinants used to develop ECOS Study filed in Case 16-E-0060.
36 Billing Determinants used to develop ECOS Study filed in Case 18-E-0067.
37 Billing determinants used to develop ECOS study filed in Case 17-E-0238.
38 Billing Determinants used in Case 15-E-0283 et. al.
39 Billing Determinants used in Case 15-E-0283 et. al.
40 The months of June, July, August, and September
41 All other months

F. JU Load Data, Hourly Aggregate System Load

The website links and contact information listed below provide access to each utility's 2017 hourly aggregate system load data, which is the summation of the generation and interchange meter points that make up each utility's subzone. This load, reported in kWh or MWh, is calculated by the New York Independent System Operator to provide the load on an hourly basis that equals the aggregate load of all load serving entities (utility supplied, NYPA supplied, Municipal load, and ESCO supplied load). This load includes the municipal and co-op loads as well as the impact of the small "load modifying" generators.

1. Central Hudson Gas & Electric Corporation

Central Hudson will make 2017 hourly aggregate system load data available by April 16, 2018 on the following website. http://inet.cenhud.com/ic_esco/general_information/usefulinfo.htm

2. Consolidated Edison / Orange and Rockland

To obtain 2017 hourly system load data for Con Edison and Orange and Rockland, please send a request via email to atzlw@coned.com, flishenbaumy@coned.com and ruggieroc@coned.com. Please use the subject line "VDER Rate Design Working Group – System Load Data Request" and specify whether the request for Con Edison data, Orange and Rockland data, or both.

3. National Grid - Niagara Mohawk

National Grid will make 2017 hourly aggregate system loads available for download in Microsoft Excel format on its System Data Portal under the "Company Reports" tab (http://ngrid.maps.arcgis.com/apps/MapSeries/index.html?appid=4c8cfd75800b469abb8febca4d5dab59) starting the week of April 16, 2018.

Starting April 12, 2018 and until it is available for download, you may request the Excel file by emailing Lauri Mancinelli at lauri.mancinelli@nationalgrid.com (for faster response, please also copy Toby Hyde at toby.hyde@nationalgrid.com and Michael Duschen at michael.duschen@nationalgrid.com).

4. New York State Electric & Gas Corporation

The link below provides access to the website page with NYSEG's 2017 Monthly Load (MLOAD) data.
http://www.nyseg.com/SuppliersAndPartners/distributedgeneration/default.html
Historical Hourly System Load Data will be a choice in the section labeled "in the spotlight"

5. Rochester Gas and Electric Corporation

The link below provides access to the website page with RG&E's 2017 Monthly Load (MLOAD) data.
http://www.rge.com/SuppliersAndPartners/distributedgeneration/default.html
Historical Hourly System Load Data will be a choice in the section labeled "in the spotlight"

G. JU Load Data, Class Load Shape Profiles

The website links and contact information listed below provide access to each utility's class load shapes.

1. Central Hudson Gas & Electric Corporation

Central Hudson customer class profiles include three 24 hour profiles - weekday, Saturday and Sunday/holiday for each month and each segment. Class specific load profile data by stratum as utilized for load reporting to the NYISO is available on the Company's web site at the following link: http://inet.cenhud.com/ic_esco/general_information/loadpf2.htm

2. Consolidated Edison / Orange and Rockland

To obtain class load shapes for Con Edison and Orange and Rockland, please send a request via email to atzlw@coned.com, flishenbaumy@coned.com and ruggieroc@coned.com. Please use the subject line "VDER Rate Design Working Group – Class Load Shape Request" and specify whether the request is for Con Edison data, Orange and Rockland data, or both. The load shapes are extrapolated class level hourly load shapes, at the customer level, converted to percent of annual max.

3. National Grid - Niagara Mohawk

Class specific 8760 unitized load profiles as utilized by the Company for billing and settlement are available on the Company's web site at the following link: https://www.nationalgridus.com/Upstate-NY-Business/Supply-Costs/Load-Profiles

National Grid customer class profiles are load profiles forecasted at the 'normal temperature' for that day. As part of the forecasting process, the most recent calendar year actual annual profiles are segmented by season, day-type and temperature. For each season, day-type, and temperature bin an average daily profile is created. The profile for forecast date is the average season/day-type profile at the normal temperature for that date, where the the normal temperature is the average temperature over the last 10 years.

4. New York State Electric & Gas Corporation

NYSEG customer class profiles include three 24 hour profiles - weekday, Saturday and Sunday/holiday for each month and each segment. NYSEG customer class profiles are available on NYSEG's website: http://www.nyseg.com/SuppliersAndPartners/electricityescos/loadprofiles.html

- Go to Profiles and then click on "Starting July 1, 2016"
- There is one excel spreadsheet which contains separate tabs for each Rate Class of the Day Type Profiles (Weekday, Saturday, Sunday) for each:
  - "Seg032_SC 1" is for the Residential SC 1 Rate Class;
  - "Seg037_SC 6" is for the Non-residential SC 6 Rate Class

5. Rochester Gas and Electric Corporation

RG&E customer class profiles include three 24 hour profiles - weekday, Saturday and Sunday for each month and each segment. RG&E customer class profiles are available on RG&E's website: http://www.rge.com/SuppliersAndPartners/electricityescos/loadprofiles.html

- Go to Profiles and then click on "Effective July 1, 2016"
- There is one excel spreadsheet which contains separate tabs for each Rate Class of the Day Type Profiles (Weekday, Saturday, Sunday) for each month.
  - "101" is for the Residential SC 1 Rate Class;
  - "201" is for the Non-residential SC 2 Rate Class

H. JU Methodology for Recovering ICAP Costs

1. Consolidated Edison

Customer Class	**Recovery Method for Electric Capacity Costs**
Non-demand billed mass market customers - non-TOU	Fixed rate per kWh applicable to all usage. Rate varies with NYISO capability periods.
Non-demand billed mass market customers – Voluntary TOU	SC1 Rate II – fixed rate per kWh applicable to usage only during peak periods. Rate varies with NYISO capability periods. SC1 Rate III – annual capacity costs recovered through a fixed rate per kWh applicable to usage only during "super peak" periods (weekdays 2:00 pm to 6:00 pm, June through September). Rate varies with NYISO capability periods.
Demand billed customers not subject to mandatory hourly pricing – non-TOU	Fixed rate per billed kW. Rate varies with NYISO capability periods.
Demand billed customers not subject to mandatory hourly pricing – TOU	Fixed rate per billed kW applicable only during peak periods (i.e., summer 8:00 am to 6:00 pm, winter 8:00 am to 10:00 pm). Rate varies with NYISO capability periods.
Mandatory hourly pricing customers	Fixed rate per kW applicable to ICAP tag. Rate varies monthly based on the results of the NYISO's Monthly capacity auction for that month.

2. Orange and Rockland

Customer Class	**Recovery Method for Electric Capacity Costs**
Non-demand billed mass market customers - non-TOU	Fixed rate per kWh applicable to all usage. Rate varies with NYISO capability periods.
Non-demand billed mass market customers – Voluntary TOU	Fixed rate per kWh applicable to all usage. Rate varies with NYISO capability periods.
Demand billed customers not subject to mandatory hourly pricing – non-TOU	Fixed rate per kWh applicable to all usage. Rate varies with NYISO capability periods.
Demand billed customers not subject to mandatory hourly pricing – TOU	Fixed rate per kWh applicable to all usage. Rate varies with NYISO capability periods.
Mandatory hourly pricing customers	Fixed rate per kW applicable to ICAP tag. Rate varies monthly based on the results of the NYISO's Monthly capacity auction for that month.

3. National Grid - Niagara Mohawk

Customer Class	Recovery Method for Electric Capacity Costs
Non-demand billed mass market customers - non-TOU	Residential and Small commercial customers (SC1 / SC2ND) are charged for capacity via their $/kwh supply charge over all on peak hours. For each month the forecasted LBMCP in $/kW-mo times the sum of one plus the Unforced Capacity Requirement of the NYISO, times the sum of one plus the Demand Curve Requirement of the NYISO divided by the number of on peak hours of the applicable month divided by the respective Class Load Factor will be added to the on peak price in Rule No. 46.1.1.1;
Residential and Farm Service – Optional TOU, Small Commercial Demand, Large General Service non-mandatory hourly pricing	SC1C, SC2, SC3 non MHP customers get charged capacity for each hour between 12 noon and 8 pm on weekdays: For each hour between 12:00 noon and 8:00 PM on weekdays (excluding any Holiday that falls on a weekday) the forecasted LBMCP in $/kW-mo times the sum of one plus the Unforced Capacity Requirement of the NYISO, times the sum of one plus the Demand Curve requirement of the NYISO, divided by hours between 12:00 noon and 8:00 PM on weekdays (excluding any Holiday that falls on a weekday) of the applicable month divided by the respective Class Load Factor.
Residential Optional TOU	SC1 VTOU customers are charged for capacity like the group above except during the months of June, July, and August. For SC1 (Special Provision L) during the months of June, July & August, Rule 46.1.2.2 will be zero. However, a Super Peak billing rate will be applied to all kWhs billed during the Super Peak periods. The rate will be based upon a load-weighted calculation of Rule 46.1.2.2, with the modification that the hours of 2:00 pm to 6:00 pm on weekdays (excluding any holiday that falls on a weekday) be used in the calculation (replacing the hours of 12:00 pm to 8:00 pm). The Super Peak billing rate will be included on Supply Service Charge Statement in Rule 46.4.
Hourly pricing demand-based service classes	Larger customers with ICAP tags (SC3 Provision L, SC3A /MHP) get charged for capacity on a $/Kw rate multiplied by their ICAP tag: Effective May 1, 2012, a customer-specific peak load demand charge shall be calculated based on the customer's unique Capacity Tag assigned for the duration of each NYISO Capability Year and on the forecasted NYISO Capacity Spot Market price, and shall be assessed in each monthly billing period.
	Capacity revenues and costs are reconciled for all customers through the ESRM.

4. **New York State Electric & Gas Corporation / Rochester Gas and Electric Corporation**

Customer Class	Recovery Method for Electric Capacity Costs
Non-demand based service classes (i.e., Mass Market)	The capacity component is calculated using the market-clearing price of capacity as determined from the NYISO's monthly and spot capacity auctions. The capacity price includes capacity losses and reserves. The service class profile is used to determine the customer's capacity responsibility of state-wide system peak demand. A new capacity responsibility amount is determined each May 1. The service class profile contribution to the system peak demand may be adjusted for a growth factor. The cost of capacity for the month is converted to $/kWh based on service class load profile kwh.
Non-hourly pricing demand-based service classes and Residential Time-of-Use Service classes	The capacity component is calculated using the market-clearing price of capacity as determined from the NYISO's monthly and spot capacity auctions. The capacity price includes capacity losses and reserves. The service class profile is used to determine the customer's capacity responsibility of state-wide system peak demand, and for time-of-use classes the capacity component is applied to on-peak hours only. A new capacity responsibility amount is determined each May 1. The service class profile contribution to the system peak demand may need to be adjusted for a growth factor. The cost of capacity for the month is converted to $/kWh based on service class load profile kwh.
Hourly pricing demand-based service classes	The capacity component is based on each customer's specific demand at the time of the New York system peak of the prior year. The customer's specific demand is multiplied by the $/kW capacity price, determined from the NYISO's monthly and spot capacity auctions, in effect for that billing period. The capacity price includes losses and reserves. The capacity responsibility is established for each customer each April and in effect beginning May 1. When hourly data is not available, the appropriate service class load profile is used to determine the customer's capacity responsibility.
	Capacity costs are reconciled through the monthly supply adjustment charge.

5. Central Hudson Gas & Electric Corporation

Customer Class	**Recovery Method for Electric Capacity Costs**
Non-Hourly Priced Classes, including the Residential TOU Rate Structure in Effect prior to 12/1/2017	Capacity costs are bundled within the Company's Market Price Charge (MPC) which recovers the total supply cost incurred on behalf of full service customers on a per kWh basis. Total capacity costs incurred during a month, excluding costs recovered through Hourly Pricing and TOU, as discussed below, are allocated to the MPC Groups based on each MPC Group's average load shape, as expressed as the average ratio of total NYISO hourly Day-Ahead Locational Based Market Price (DAM) costs to MWh for each MPC Group, and an estimate of the sales over which such costs will be recovered.
Residential Time-of-Use Effective December 1, 2017	Capacity costs are set twice a year for the periods September 1 through May 31 (winter rate) and June 1 through August 31 (summer rate) and are applied to on-peak usage (weekdays 2 pm to 7 pm). The winter rate is determined based on the historic monthly per kWh rates applicable to SC 1 residential customers for the period November 1 through April 1 applied to total profiled usage for the same time period and divided by profiled on-peak usage for the aforementioned nine months. The summer rate is determined based on the historic monthly per kWh rates applicable to SC 1 residential customers for the period May 1 through October 1 applied to total profiled usage for the same time period and divided by profiled on-peak usage for the aforementioned three months.
Hourly pricing demand-based service classes	The capacity charge is based on the monthly NYISO Spot Auction price for the capacity zone(s) from which the capacity is acquired pursuant to the requirements of the NYISO for the prior calendar month. Each customer's capacity responsibility is determined based on the customer's demand during the previous summer's NYCA peak hour, adjusted pursuant to the NYCA peak load forecast for the corresponding capability period and NYISO UCAP requirements. Capacity responsibility is effective May 1 through April 30.
	Capacity costs are reconciled through the monthly Market Price Adjustment.