Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 1 of 118



RAP Energy solutions for a changing world

Standby Rates for Combined Heat and Power Systems

Economic Analysis and Recommendations for Five States

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Standby Rates for Combined Heat and Power Systems:

Economic Analysis and Recommendations for Five States

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Table Of Contents

Foreword
Executive Summary
Introduction
Chapter 1. Best Practices in Standby Rate Design
Chapter 2. Economic Analysis for Study
Chapter 3. Arkansas
Chapter 4. Colorado
Chapter 5. New Jersey
Chapter 6. Ohio
Chapter 7. Utah
References
Attachments

List of Figures

Fig	ure 1: Illustration of Self-Generatin	g Customers	' Purchase Power Red	quirements	
· · O					

List of Tables

Table 1: Selected Utilities and State Regulators	9
Table 2: Illustrative Coincidence Factors 1	.0
Table 3: Impact of Coincidence Factor on Demand Charges 1	.2



List of Acronyms and Abbreviations

AG	Average Generation	LPS	Large Power Service
BAI	Brubaker & Associates, Inc.	мм	Maximum Monthly
BD	Billing Demand	NCP	Non Coincident Peak Demand
CD	Contract Demand	OAD-SBS	Open Access Distribution Standby Service
СНР	Combined Heat and Power	OATT	Open Access Transmission Tariff
СР	Coincident Peak Demand	ORNL	Oak Ridge National Laboratory
CRES	Certified Retail Electric Service	PSCo	Public Service Company of Colorado
DOE	(U.S.) Department of Energy	PURPA	Public Utility Regulatory Policies Act
DR	Demand Rate	RAP	Regulatory Assistance Project
EAI	Entergy Arkansas, Inc.	RMP	Rocky Mountain Power
EV	Expected Value	SBS	Standby Service
FERC	Federal Energy Regulatory Commission	SR	Standby Rate
FOR	Forced Outage Rate	SSO	Standard Service Offer
GW	Gigawatts	SSR	Standby Service Rider
kW	Kilowatts	STB	Standby Service Rider
LGS	Large General Service	VAR	Voltage Adjustment Rider



Foreword

mprovements in technology, low natural gas prices, and more flexible and positive attitudes in government and utilities are making distributed generation more viable. With more distributed generation, notably combined heat and power, comes an increase in the importance of standby rates, the cost of services utilities provide when customer generation is not operating or is insufficient to meet full load.

This work digs into existing utility standby tariffs in five states. It uses these existing rates and terms to showcase practices that demonstrate a sound application of regulatory principles and ones that do not.

In cases where we find deficiencies, it is not to embarrass, but rather to call attention to opportunities for improving a set of rates that are often governed by the outmoded idea that distributed generation is rare and inherently risky to utility operations and customers. Also, these rates do not get a lot of attention and likely are due for reassessment soon in many jurisdictions.

Trends show that distributed generation is not rare anymore and that old ideas about risk have been replaced by utility operator confidence in anticipated performance, which stems from interconnection agreements and probabilistic assessments. Rates and charges that may have been set roughly can be modified to apply better matching of utility costs with the services customers use. The context for this work, then, is part of a trend to a more customer-focused utility sector that not only looks to provide good service, but looks to the consumer as a resource.

We find many areas for improvement in standby rates. Will utilities and their regulators take steps to consider and execute these changes? Time will tell, but with technology driving applications and deployment, utilities and their regulators will be hard-pressed to do any less than steward this progress.

> **Richard Sedano** Director, US Programs Regulatory Assistance Project



Executive Summary

services:

- **Backup power** during an unplanned generator outage;
- Maintenance power during scheduled generator service for routine maintenance and repairs;
- **Supplemental power** for customers whose onsite generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customer's rate class;
- Economic replacement power when it costs less than onsite generation; and
- **Delivery** associated with these energy services. This paper presents the results of an analytical assessment of the rates, terms, and conditions for standby service in five states: Arkansas, Colorado, New Jersey, Ohio, and Utah. Specifically the study evaluated the efficacy of standby tariffs for combined heat and power (CHP) applications.

This paper sets forth options to improve the tariffs analyzed and the estimated economic impact of the suggested tariff improvements for a selected set of proxy utility customers who have CHP systems. Although the study and recommendations targeted participating states, the analytical methods, spreadsheets, and recommendations can be adapted for use by other jurisdictions.¹

Selection of States and Tariffs for Analysis

The Regulatory Assistance Project (RAP) identified candidate states for the project considering geographic diversity, representation of states with restructured electricity markets as well as those that remain vertically integrated, and the jurisdictions' interest in reviewing standby tariffs. To keep the project manageable, RAP and Brubaker & Associates, Inc. (BAI) worked with state regulatory commission staff to select a single investor-owned utility for tariff evaluation:

State	Utility	Tariff(s)		
Arkansas	Entergy Arkansas, Inc.	Standby Service Rider		
Colorado	Public Service Company of Colorado	Schedule PST Schedule TST		
New Jersey	Jersey Central Power & Light Company	Rider STB		
Ohio	AEP-Ohio Power Company	Schedule SBS Schedule OAD-SBS		
Utah	Rocky Mountain Power	Schedule 31		

Coordination With State Regulatory Commissions

RAP and BAI presented the results of the economic analysis and recommendations to regulatory commission staff and provided an opportunity for review and comment. In some cases, public workshops were held with commissioners, utility representatives, affected customer groups, and other stakeholders. This interactive process informed and enhanced the development of the analyses and recommendations presented in this paper.

Description of Analytical Methods

BAI estimated economic impacts of the standby tariffs using an Excel spreadsheet model customized for each tariff analyzed. The model calculates standby service costs under the currently effective standby rates. When practical, models were also used to calculate the costs resulting from the tariff modifications.

 For state specific attachments and a link to the Excel model for each state, please go to: http://www.raponline. org/featured-work/standby-rates-for-CHP



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 7 of 118

Standby Rates for Combined Heat and Power Systems

Standby Rate Tariff Structures

While standby rates vary widely, they typically include the following:

- A *capacity reservation charge* is a charge to compensate the utility for the capacity that the utility must have available to serve a customer during an unscheduled outage of the customers own generation unit.
- **Capacity and energy charges** for the actual electricity supplied to a customer during an unscheduled outage of the customer's own generation unit.
- A *maintenance capacity charge* for the capacity supplied by the utility during a scheduled outage of the customer's own generation unit, and,
- *facility charges* to compensate the utility for any dedicated distribution costs.

Summary of Best Practices in Standby Rate Design

Based on the experience of RAP and BAI in the area of standby rate design, explained in Chapter 1, the following are best practices for consideration in the development of standby rates:

Allocation of Utility Costs

- Generation, transmission, and distribution charges should be unbundled in order to provide transparency to customers and enable appropriate and cost-based standby rate design.
- Supplemental power charges should be based on charges in the applicable full requirements tariff.
- Generation reservation demand charges should be based on the utility's cost and the forced outage rate of customers' generators on the utility's system.

Judgments Based on Statistical Method

- Standby rate design should not assume that all forced outages of on-site generators occur simultaneously, or at the time of the utility system peak.
- Transmission and higher-voltage distribution demand charges should be designed in a manner that recognizes load diversity.
- Standby rate design should assume that maintenance outages of on-site generators would be coordinated with the utility and scheduled during periods when system generation requirements are low.

Value of Customer Choice and Incentives

- Daily maintenance demand charges should be discounted relative to daily backup demand charges to recognize the scheduling of maintenance service during periods when the utility generation requirements are low.
- Customers should have the option to purchase all or some portion of their standby service on an interruptible basis and thereby avoid generation reservation demand charges.
- Pro-rated, daily, as-used demand charges for backup power and shared transmission and distribution facilities should be used to provide an incentive for generator reliability.
- Customers should be able to procure standby service from competitive power providers at prevailing market prices, where available.

Recommendations for Standby Tariff Modifications

Based on RAP's and BAI's experience in standby rate design and the analyses conducted by the study's authors, the following are potential modifications to the rate designs, terms, and conditions of the standby tariffs analyzed. Descriptions of the current tariffs appear in the corresponding chapters.

Arkansas – Entergy Arkansas Inc.'s (EAI) Standby Service Rider SSR (Chapter 3)

- The reservation demand charge should be unbundled into generation, transmission, and distribution components.
- The unbundled generation component of the reservation demand charge for standby service should be set such that it is equivalent to the best FOR exhibited by any generating unit on EAI's system.
- The reservation demand charge should be differentiated by season.
- The daily backup and maintenance demand charges should apply only during on-peak periods.
- The daily backup and maintenance energy charges should be differentiated on a time of-use basis.
- Customer-generators should have the option to buy backup power from the market through the utility and avoid monthly reservation charges for standby generation service.
- The Non-Reserve Service feature of Rider SSR should be modified to facilitate the provision of interruptible standby service.



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 8 of 118

Standby Rates for Combined Heat and Power Systems

- Standby charges for shared transmission and distribution facilities should reflect load diversity.
- Standby charges should be concise and easily understandable. Customers who may consider installing a CHP system may have a difficult time understanding all of the charges they may pay under various circumstances with the standby tariffs and riders EAI has in place today.
- The standby tariffs should specify the circumstances under which a special contract may be warranted.

Colorado – Public Service Company of Colorado (PSCo) Schedules PST and TST (Chapter 4)

- The Grace Energy Hours provision should be eliminated and replaced with a lower generation reservation fee coupled with a daily demand charge.
- The generation reservation fee should reflect the best FOR exhibited by any customer's generating unit on PSCo's system.
- Daily demand charges should be implemented to provide incentives to improve the performance of self-generating units.
- The standby backup demand charges for generation, transmission, and certain distribution costs should apply only during on-peak hours.
- Customers should have the option to buy backup power at prevailing market prices through the utility if available and thereby avoid standby generation charges.
- Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (in kilowatts [kW]) within a required timeframe and avoid standby generation charges.
- Standby rates for shared distribution facilities should reflect load diversity.
- The generation and transmission cost components of the reservation fee should be unbundled.

New Jersey – Jersey Central Power & Light Company Standby Service Rider STB (Chapter 5)

- Scheduled maintenance hours should be allowed for all standby customers. The tariff states that customers who commence service after February 25, 1993 are not allowed to schedule maintenance for their generating units.
- Standby service should be available to all customergenerators regardless of the availability factor of their generating unit.
- Standby tariffs should be concise and easily understandable. Customers may have difficulty understanding this tariff because of the different types of demand measurements and the manner in which charges are assessed.
- Standby charges for shared distribution facilities should reflect load diversity.²

Ohio – AEP-Ohio Power Company's Schedules SBS and OAD-SBS (Chapter 6)

- Generation reservation charges should reflect the best FOR exhibited by any generating unit on the system.
- Daily demand charges should be developed to provide incentives to improve generator performance.
- Customers should have the option to buy backup power from the market.³
- Charges for distribution facilities should reflect load diversity.
- The distribution component of the reservation charge should be adjusted to include only the cost associated with dedicated distribution facilities. The tariffs should be concise and easily understandable.
- The tariffs should specify that special circumstances may warrant a special contract.

- 2 Rider STB may already recognize load diversity. The standby distribution charges are substantially below the full requirements service distribution charges.
- 3 By the end of 2015, all customers of AEP-Ohio Power Company will be able to choose an alternative electricity supplier.



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 9 of 118

Standby Rates for Combined Heat and Power Systems

Utah – Rocky Mountain Power Schedule 31 and Schedule 33 (Chapter 7)

- The on-peak backup charges should be calculated and stated on a seasonal basis.
- The generation reserve charge should be modified to reflect the performance of the best generating unit.
- The shared transmission and distribution standby demand charges should be adjusted to reflect load diversity.
- The distribution component of the reservation charge should be adjusted to include only the cost associated with dedicated distribution facilities.
- Customers should have the option to buy backup power from the market through the utility and thereby avoid backup charges for standby power.
- Customers should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (kW) within a required timeframe to mitigate all, or a portion of, the backup demand charges.
- Customers should be allowed to take a total of up to 30 days of maintenance power per year without the current constraint of taking this service only twice during the year.



Introduction

tandby, or partial requirements, service is the set of retail electric products for customers who have onsite, non-emergency generation, such as combined heat and power (CHP). By simultaneously producing useful electric and thermal energy from a single fuel source at a customer's site, CHP enhances energy efficiency, improves environmental quality, and makes businesses more competitive.

Utility standby rates cover some or all of the following standby services (see Figure 1):⁴

- **Backup power** during an unplanned generator outage;
- *Maintenance power* during scheduled generator service for routine maintenance and repairs;
- Supplemental power for customers whose onsite generation under normal operation does not meet all of their energy needs, typically provided under the full requirements tariff for the customers rate class;
- *Economic replacement power* when utility power costs less than onsite CHP generation; and
- *Delivery* associated with these energy services. On August 30, 2012 President Obama issued an

Executive Order⁶ that sets a goal of 40 gigawatts (GW) of new, cost-effective industrial CHP in the United States by 2020, a 50-percent increase from today. Meeting this goal would save energy users an estimated \$10 billion

Figure 1



per year, result in \$40 to \$80 billion in new capital investment in manufacturing and other facilities, create American jobs, and reduce emissions equivalent to 25 million cars.

Standby rates are an important factor in determining the relative economics of CHP applications, compared to taking full requirements service from an electric utility or alternative electricity supplier. Charges or terms and conditions of a standby tariff that would result in excessive costs for standby service would unnecessarily discourage CHP development, an inherently more energyefficient technology than taking traditional utility or alternate supplier power.

RAP and others have documented best practices in standby rate design and utility tariffs that exemplify these principles.^{7,8} Building on this foundation, RAP recruited state regulatory commissions to work with a technical consultant to review standby tariffs in place today against these approaches and take preliminary steps to consider tariff improvements to facilitate adoption of CHP systems.

With funding from the U.S. Department of Energy (DOE) and under contract to Oak Ridge National Laboratory (ORNL), RAP hired Brubaker & Associates, Inc. (BAI) to perform the economic analysis of standby tariffs in five states, work with RAP to recommend possible tariff modifications that could improve their efficacy for CHP applications, and quantify the potential economic impact of the recommended improvements for proxy industrial and commercial customers.

RAP and BAI conducted a preliminary assessment of standby rates in selected states to identify tariffs that

- 4 In restructured states, the utility may provide only delivery services and provider-of-last-resort energy service.
- 5 Source: Brubaker & Associates.
- 6 The White House, Office of the Press Secretary, 2012.
- 7 See, in particular, Weston, et al., 2009. For examples of current utility standby practices, see Stanton, 2012.
- 8 Johnston, et al., 2008.



Table 1

Selected Utilities and State Regulators

Utility	Regulatory Jurisdiction
Ohio Power Company (AEP)	Public Utilities Commission of Ohio
Entergy Arkansas, Inc.	Arkansas Public Service Commission
Rocky Mountain Power Company (PacifiCorp)	Public Service Commission of Utah
Public Service Company of Colorado	Colorado Public Utilities Commission
Jersey Central Power & Light Company (FirstEnergy)	New Jersey Board of Public Utilities

present opportunities for improvement that would make them more attractive for CHP applications, while adhering to ratemaking principles. To some extent, the selection process was random. However because cooperation was needed from the state regulatory agencies, consideration was given to states where there was a past working relationship with RAP. In cooperation with regulatory utility commission staff, one utility per state was selected for detailed tariff review and analysis (see Table 1).

The tariffs were first analyzed at a conceptual level to understand each component and the manner in which these components interact with one another, associated tariff riders, and applicable full requirements tariffs. The project team then identified specific areas where tariff modifications could be made to reduce hurdles to installation of cost-effective CHP systems. BAI developed a Microsoft Excel model for each state to quantify the economic impact of the tariffs currently in place and evaluate the proposed tariff enhancements. The model runs use only publicly available information: (1) the rates, terms, and conditions in the relevant tariffs, and (2) customer usage and load characteristics, standby power needs, and generator sizes and types developed by each state project team to represent industrial and commercial customers with promise for adopting CHP. This report is organized into three major sections:

- **Best Practices in Standby Rate Design** sets forth basic concepts for understanding the economics of standby rate design, discusses the economic and policy criteria that establish the foundation for good standby rate designs, and describes best practices in standby rate design.
- Economic Analysis for Study discusses the process for the selection of representative customergenerators for analysis, describes the process used to identify potential improvements and enhancements to the standby tariffs analyzed in the study, and

discusses the modeling methods and assumptions used to quantify the potential economic impact of the proposed tariff improvements.

• **State-Specific Standby Rate Analyses** describe the standby tariffs examined, assess the efficacy of the tariffs for CHP applications, recommend improvements to the tariffs, and present the economic analysis.

Appendices to this document (available online) include the standby power tariffs surveyed, detailed results of economic analyses performed for this study, work papers supporting the analysis and recommendations, and a list of resources for additional information on standby rates.

Definition of Key Concepts

Following are central rate design concepts important for understanding the economic rationale behind the design of standby rates.

Backup power is electric capacity and energy supplied by an electric utility during an unscheduled outage of the customer's on-site generation. Thus, backup power is supplied by the utility on a random basis to replace capacity and energy ordinarily generated by a customer's own generation equipment.

Capacity/demand charges are charges based on a customer's highest usage in a one hour or shorter interval during a billing cycle.

Energy charges are the part of the charge for electric service based upon the electric energy consumed or billed.

Maintenance power is electric capacity and energy supplied by an electric utility during scheduled outages of the customer's on-site generation. This type of power is provided on a prearranged, scheduled basis to allow the customer to take its equipment out of service for routine inspections and preventive maintenance.



Table 2

Demand Ratchets: Some tariffs set the billing demand at the higher of (1) the current month's measured demand or (2) a fraction (typically 60 or 90 percent, but sometimes as much as 100 percent) of the customer's highest measured demand in the previous year or in the past peak season. This type of pricing is referred to as a "demand ratchet."⁹

Reserve Capacity/Reserve Margin/Reserves are the amount of capacity that a system must be able to supply, beyond what is required to meet demand, in order to assure reliability when one or more generating units or transmission lines are out of service. Traditionally a 15-20 percent reserve capacity was thought to be needed for good reliability. In recent years, the accepted value in some areas has declined to 10 percent.

Supplemental power is electric capacity and energy supplied by an electric utility that is regularly used by a self-generating customer in addition to capacity and energy from on-site generation. Because this service usually is available "around the clock" and on a "firm" basis, supplemental power is the same as full requirements service for non-generating customers. Supplemental power is typically charged at the otherwise applicable full-requirements tariff rates.

Coincidence factor is the ratio of a customer's coincident peak demand (CP) to its non coincident peak demand (NCP), or billing demand. A customer's CP is the demand imposed by the customer at the time of the utility system's maximum demand. The customer's NCP is the customer's maximum demand recorded at any time during a specified time interval. CP and NCP may be measured on a monthly or annual basis. Table 2 illustrates how coincidence factor is determined.

Both customers, FR1 and FR2, purchase full

Illustrative Coincidence Factors

Customer	Coincident Demand (kW)	Billing or Non-Coincident Demand (kW)	Coincidence Factor*		
FR1	1,000	2,000	50%		
FR2	1,000	1,250	80%		
* Column 1 ÷ Column 2					

requirements service and impose a 1,000-kW CP demand on the system. Customer FR1 has a NCP demand of 2,000 kW, while the NCP demand of Customer FR2 is 1,250 kW. Thus, Customer FR1 has a 50-percent coincidence factor (1,000 kW/2,000 kW), while Customer FR2 has an 80-percent coincidence factor (1,000 kW/1,250 kW).

The Forced Outage Rate (FOR) of a generating unit for a given time interval is defined as the number of hours that the unit is forced out of service for emergency reasons, divided by the total number of hours that the generating unit is available for service during that time interval plus the number of hours that the generating unit experiences a forced outage. The FOR of a generating unit measures the probability that the unit will not be available for service when required. Essentially the FOR provides an indication of the percentage of time that a generating unit is forced out of service for emergency reasons. The FOR is a measure of a generating unit's reliability.

9 Lazar, 2013.



Chapter 1. Best Practices in Standby Rate Design

tandby rates are typically designed to recover the fully allocated embedded costs that the utility incurs to provide standby service to selfgenerating customers and, for investor-owned utilities, a reasonable rate of return established by the applicable state regulatory commission. The federal Public Utility Regulatory Policies Act (PURPA) established the fundamental cost of service and legal principles that govern the design of standby rates. These principles have been implemented on a state-by-state basis through state regulatory commission rules and rate orders that establish utility-specific tariffs of general applicability for the provision of standby power.

In competitive electricity markets, market prices determine the charges for standby service from electricity suppliers. Generally the electricity cost of backup power (distinct from the delivery¹⁰ costs) is determined by the market price at the time of the customer-generator's outage.

Economic and Policy Principles Governing the Design of Standby Rates

In general, state regulatory utility commissions require that standby rates be based on the same cost-of-service principles that are applied to the utility's full requirements customers. These rate design principles are consistent with the requirements of PURPA that:¹¹

Rates for sales shall be just and reasonable and in the public interest and shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

Rates for sales which are based on accurate data and consistent with system-wide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

In other words, a self-generating customer should not pay more for purchased electricity from the utility than other customers having similar load and other costrelated characteristics (size, delivery voltage, and so on).

A critical issue in designing cost-based standby rates is determining the appropriate level of generation reserve capacity that a utility must carry to provide standby service to self-generators on its system. The required level of utility reserves to support standby service is a function of generator resource reliability. A self-generator having greater reliability than utility controlled resources may require reserves lower than the utility average. On the other hand, a self-generator with below-average reliability could require above-average reserves. A precise determination can only be made through longrun observed performance of the facilities in question. Methods to design prices for standby service, standby generation reservation, and daily as-used demand will be summarized in the rest of the paper. These rates and methods are also demonstrated in the online companion Excel spreadsheets with this report.

Impact of Coincidence Factor on Standby Power Requirements

Standby customers have different load characteristics than non-generating (i.e., full-requirements) customers. Whereas full-requirements customers typically impose load on the utility system 365 days a year, a reliable standby customer requires backup power only on a handful of days during random generator outages.

The effect is that a utility supplying standby power will not have to plan as much reserve capacity to serve self-generating customers as it does for full-requirements customers. There are two reasons for this. First, not all customer-generators will require standby power at the same time. Second, it is highly unlikely that such purchases will coincide with the system peak. A customer having a low coincidence factor should pay less per kW of non coincident peak, or billing demand, than another

^{11 18} C.F.R $\$ 292.305 (1)(i)(ii) and (2).



^{10 &}quot;Delivery" as used in this paper is synonymous with "transmission and distribution."

Table 3						
Impact of Coincidence Factor on Demand Charge						
Customer	1. Coincident Demand (CP kW)	2. Billing Demand (BD kW)	3. Coincidence Factor	4. Demand Costs*	5. Demand Charge** (\$/kW)	
FR1	1,000	2,000	50%	\$10,000	\$5.00	
FR2	1,000	1,250	80%	\$10,000	\$8.00	
Standby	1,000	20,000	5%	\$10,000	\$0.50	

* The demand costs are the same because they are allocated relative to coincident demand. ** Column 4 ÷ Column 2

customer having a higher coincidence factor. Generally the utility system is large enough to accommodate the needs of its self-generating customers.

Coincidence factor is relevant in designing rates because most electric utilities bill for demand on a noncoincident basis. A customer having a higher coincidence factor will impose higher demand-related costs per kW of billing demand than a customer having a lower coincidence factor. Table 3 illustrates this point.

All three customers illustrated in Table 3 impose the same coincident demand on the utility, and total demand costs are allocated relative to coincident demand. Customers FR1 and FR2 purchase full requirements service and have a coincidence factor of 50 percent and 80 percent, respectively. This is typical of a utility's full requirements customers. The standby customer, by contrast, has a five-percent coincidence factor. This may be reflective of backup power requirements over time. In some years, a forced outage may occur coincident with the peak. In other years, it may not.

All other things being equal, the lower the coincidence factor, the lower the per-unit standby demand charge needed. This is because there are more billing units (Column 2) over which to spread the allocated demandrelated costs (Column 4) for backup power than for full-requirements service. Whereas a \$5/kW or \$8/kW demand charge would be appropriate for full requirements customers, a reliable standby customer should be charged only a fraction of these amounts for standby power, or \$0.50/kW, based on the previous example.

Backup and maintenance service do not have the same coincidence with the system peak as full requirements utility service. Whether backup power service is more or less coincident than full-requirements utility service depends on the reliability of the customer's generating unit. Maintenance power, as typically defined by utility tariffs, would only be provided during times of the year when the utility has adequate generating resources available. It could therefore be argued that properly scheduled maintenance power would have a coincidence factor near zero. Forced outages, by contrast, are more random in nature.

These distinctions between the nature of backup and maintenance service have important rate design implications. Specifically, the rates

for backup power service should reflect the fact that the utility is providing only the reserve capacity. Properly scheduled maintenance power service rates should reflect both the lower cost and the off-peak nature of this service. It is a lower cost service than firm backup power because utilities generally require maintenance service to be scheduled in advance, and service may be refused if adequate resources are not available to accommodate a planned outage. This lower quality of service should be reflected in the form of a price discount for maintenance power relative to backup power service.

PURPA recognizes that backup and maintenance services are different from regular utility service. The rules state:¹²

Rates for sales of backup and maintenance power. The rate for sales of backup power or maintenance power:

- (1) shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and
- (2) shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

Generator Reliability and Standby Rate Design

The expected standby load on a utility's system represents the level of standby demand that the utility is obligated to serve. Mathematically this can be expressed as the FOR times the maximum or contract demand of the self-generating customers. In some hours, the utility's actual standby load will be greater than the expected

12 18 C.F.R § 292.305 (2c)(1) and (2).



value. In other hours, it will be less than the expected value. And in many hours, it will be zero. Unlike full requirements loads, standby customers generally will not place as much of their total contracted demand on the utility during peak periods.

The reliability of self-generators affects the cost of providing backup service. The fundamental economic principle underlying the design of backup power rates is that a utility providing backup service is incurring the costs associated with the reserve capacity, which in conjunction with the self-generating capacity, assures a reliable supply of electricity to the customer. Highly reliable self-generators will require small reserve levels; less reliable self generators will require larger reserve levels.

Costing and Pricing Standby Service

One reasonable approach to costing and pricing the generation component of standby service is to quantify the amount of reserve capacity required to provide firm standby service based on an expected level of standby demand that the utility will serve over time. This can be done independently of a class cost-of-service study.

One means of establishing the generation-related costs of providing standby service is the Expected Value (EV) method, a methodology for quantifying the amount of reserve capacity required to provide standby service. The EV method is a reasonable approach for at least two reasons. First, the EV method is easy to implement. Second, this method is consistent with cost-of-service principles in that it directly measures the probability that standby customers will or will not contribute to the need for, and use of, generation capacity.

Under this method, the amount of reserve capacity required to provide standby service is equal to the product of the FOR and the standby contract capacity. The FOR used in the EV method should reflect the longrun performance of customer-owned generation facilities. The FOR used in the EV method directly reflects the probability that an outage of a self-generating customer will occur in any given hour, and therefore provides a reasonable measure of the amount of capacity that a utility must set aside to provide standby power service.

This approach results in the design of a firm standby power rate that consists of two basic components: (1) a monthly generation reservation charge, and (2) a daily, as used demand charge. These two rate components are discussed in more detail herein.

Standby Generation Reservation Charge

The standby generation reservation charge is designed as a percentage of the demand-related generation costs recovered through the regulated demand charges that are assessed to full requirement industrial (or commercial) customers in the jurisdiction under study. The appropriate percentage of the demand charge for generation for full-requirement customers to be assessed to standby customers could be developed using historical data, if available, regarding the FORs of standby customers in the utility's service area. Specifically the standby generation reservation charge would be calculated as the product of the FOR and the demandrelated generation costs underlying the applicable fullrequirements electricity rate. The standby generation reservation charge rate would be calculated and assessed on a per kW month basis. Recommendations in this paper would use the best performing customer generators (lowest FOR) to set rates to recognize the value of reliable systems. If an average FOR is used to develop the standby generation standby charge, the customers whose selfgenerating unit is performing the best will be paying rates above the cost to serve. Average and unreliable systems can be motivated to improve through incentives embedded in other rate elements such as the daily demand charge.

This reservation charge would be billed each month of the year as the product of the per kW-month reservation charge rate and the firm standby power demand that the utility commits to provide to the standby customer by contract (the contract demand). The reservation charge would establish a minimum monthly charge that the standby customer would pay, even if the customer did not actually take any standby power service in a given month.

Some customers may wish to contract for standby capacity that fully covers the peak output of their onsite generating units, paying for firm standby service for all of their load at a set price, whereas other customers may desire a somewhat lower level of backup. Allowing individual customers to designate a contract demand specifying the level of standby capacity they wish to purchase gives customers the option to cover only a portion of their load while paying market based pricing for any energy use above that level.



Daily, As-Used Standby Demand Charge

On average, the monthly generation reservation charge would recover the utility's cost of providing firm standby service. When an individual standby customer requires more than the average amount of standby service in a particular billing period, it is appropriate to require the customer to pay additional charges to recognize the additional cost of providing service. For example, if an outage were to last an entire month, a standby customer cost would resemble a full-requirements customer.

A prorated, daily, as-used demand charge would apply when standby service is actually taken in a given billing period. The charge would be designed on a per kW day basis and assessed to the standby customer based on the maximum backup power demand that the customer imposes on the utility's system in a given day. The standby tariff terms and conditions should make a clear distinction between the purchase of standby power and supplemental power. Without this clear distinction, a customer could be charged for backup power when the power requirement should actually be met through the customer buying supplemental power.

Finally, backup and maintenance power differ from one another and from full requirement power service in that they do not have the same coincidence with the utility's system peak. Maintenance power, by definition, would only be provided during off-peak periods or periods during the year when adequate resources are available. Consequently, it would be reasonable to discount the pro-rated daily demand charges for maintenance power service relative to the daily charges that apply for normal backup power service.



Chapter 2. Economic Analysis for Study

AI performed an economic analysis of standby tariffs for selected utilities in each of the five states included in the study. The analyses were designed to assist the state regulatory commissions in evaluating the costs and benefits associated with current standby rate designs and potential enhancements. The economic analysis compares the standby costs for specific example CHP systems to determine the impact of existing standby rates and suggested tariff changes on CHP project economics.

BAI developed a Microsoft Excel model for each of the standby tariffs addressed, quantifying the change in costs that would result from implementing the tariff modifications proposed by BAI and RAP. A description of each state-specific model is included online in Attachment 1 to this report. The spreadsheets are also publicly available for other states, customers, and stakeholders to adapt for their own circumstances.¹³

This chapter provides a high-level review of the process that BAI used to develop the economic modeling.

Selection of Representative Customer Usage Characteristics

The first step in developing the economic model for the selected utility tariffs was to designate the representative customer characteristics used to quantify the cost of providing standby service under the existing and alternative proposed rate designs. The customer usage and load characteristics modeled in the study were based on discussions with state regulatory commission staff. In some instances, databases of existing CHP customers in the state, or customer types most likely to develop CHP systems in the state, were used to develop the scenarios studied. However, in each instance the state regulatory staff had the final say as to the size of load that was studied. This also applied to the selection of the forced outage rates that were analyzed.

In general, the process resulted in the selection of characteristics deemed to be appropriate to represent small, medium, and large nonresidential customers.

Description of Modeling Methods

Each model calculates the costs to self-generation customers under various scenarios. Each model allows the user to input representative customer characteristics such as load factor and peak demand, as well as generating unit characteristics such as net capability and assumed outage hours. The spreadsheet includes actual standby service rates for the selected utility, including the core standby tariff and applicable riders and supplemental power tariffs.

Customer and generator characteristics and rate inputs were then used to estimate the cost of taking standby service under the applicable standby rate schedules. After developing the core spreadsheet used to model costs under existing rates, BAI in some instances developed separate spreadsheets to isolate the economic impact of implementing the proposed standby rate modifications recommended by the study for each jurisdiction. In some cases, BAI adjusted rates to simulate the proposed modifications.

Discussion of Modeling Assumptions

Each state model was designed in a manner that allows the user to select assumptions for critical inputs such as forced outage hours, unit maintenance hours, customer load size for both standby and supplemental power requirements, and customer load factor. Once these assumptions are selected, the model calculates the resulting costs under existing tariff rates. This approach gives the user the flexibility to analyze the economic impact of the existing and modified standby rates under a wide range of load and generation assumptions. Depending on the suggested tariff modifications, the model could be used to calculate the revised costs. This would require adjusting the rates in the model that calculates costs under the current tariff.

¹³ For state specific attachments and a link to the Excel model for each state, please go to: http://www.raponline.org/ featured-work/standby-rates-for-CHP

Identifying Potential Tariff Modifications

BAI and RAP developed the potential tariff enhancements recommended in this study in two interrelated steps. First, BAI and RAP reviewed and analyzed the standby tariff components for each selected state utility to understand the rates, terms, and conditions of each tariff; determine how each rate component is calculated; and evaluate the manner in which the various elements of the tariff work together or potentially contradict one another. Second, BAI and RAP evaluated the tariffs against best practices in standby rate design and identified modifications to the tariffs that could enhance their efficacy for CHP applications and move them closer to a best practices model.

A detailed discussion of the proposed tariff modifications for each of the five selected utility standby rates is provided in each state-specific chapter of this report.



Chapter 3. Arkansas

Standby Rates for Customers of Entergy Arkansas, Inc.

Description of Standby Rates

ntergy Arkansas, Inc. (EAI) offers a Standby Service Rider (SSR) under Rate Schedule No. 20. The SSR is available to customers who ✓ have their own generating equipment and have executed a contract for standby service with EAI. The SSR is comprised of four service offerings:

- 1. Reserved Service is the electric energy and capacity that EAI stands ready to supply during a scheduled or unscheduled outage of the customer's on-site generation equipment.
- 2. Maintenance Service is the electric energy and capacity supplied by EAI during scheduled outages of the customer's generating equipment. Maintenance Service is available during the service months of October through May and during the off-peak hours of the service months June through September.
- 3. Non-Reserved Service is the electric energy and capacity EAI may supply during a scheduled outage of the customer's on-site generation equipment. Non-Reserved Service is only available during the service months of October through May. EAI, in its sole discretion, may approve or deny any request for Non-Reserved Service.
- 4. Backup Service is the electric energy and capacity supplied by EAI during an unscheduled outage of the customer's electric generating equipment, as well as the energy and capacity supplied by EAI during a scheduled outage that exceeds the sum of scheduled Maintenance Service and any scheduled Non-Reserved Service

Description of Standby Charges

- The SSR tariff includes eight charges:
- 1. A monthly customer charge
- 2. A monthly reservation charge
- 3. Seasonal maintenance demand charges expressed on a daily basis
- 4. Seasonal backup demand charges also expressed on a daily basis
- 5. A monthly demand charge for Non-Reserved Service

- 6. Seasonal maintenance energy charges
- 7. Seasonal backup energy charges
- 8. Seasonal energy charges for Non-Reserved Service

The reservation demand charge is a flat \$/kW-month rate across the entire year. EAI's demand and energy charges for Maintenance and Backup Service vary by season. The seasonal charges are higher during the billing months of June through September (the "Summer Period"), while charges are lower for all other months of the year (defined as the "Other Period"). The tariff defines on-peak hours for the Summer Period and the Other Period. However, SSR rates (except for seasonal maintenance energy charges, as noted above) do not contain any time-of-use differentiation between on-peak and off-peak periods.

SSR demand charges, including the reservation charge, are bundled charges that incorporate generation, transmission, and distribution costs. The reservation charge and the various demand and energy charges vary with the customer's voltage level of service (secondary, primary, or transmission). In addition, these charges are adjusted to reflect the customer's metering points. The energy charges in the SSR are consistent with the energy charges in EAI's full service rates - Large General Service (LGS) and Large Power Service (LPS).

Assessment of Standby Rates

The following are suggested modifications to EAI's standby tariffs for consideration:

• Lack of transparency and clarity. None of the EAI rate schedules we reviewed unbundle generation, transmission, and distribution charges, so customers do not know how much they are paying for each component of service and what charges might be avoidable with reliable onsite generation. Furthermore, some provisions of the SSR tariff appear to be in conflict with one another. For example, the tariff indicates that during the months of June through September maintenance energy can only be scheduled during off-peak





periods. However, the same provision also states that maintenance service will not be scheduled for a continuous period of less than one day. The latter requirement dictates that maintenance energy must effectively be scheduled during on-peak hours.

- · Lack of price signals to provide incentives to improve operation of on-site generating units and use utility resources more efficiently. Adding daily demand and energy charges for both backup service and maintenance service could achieve these goals. Daily demand charges could be unbundled into separate charges for the generation, transmission, and distribution cost components. In addition, the generation and transmission components of the demand charge, as well as the charge for non dedicated distribution facilities, could be assessed only during the on-peak period. Furthermore, seasonal energy (per kWh) charges could distinguish on-peak and off-peak usage to better capture the costs that EAI is actually incurring to serve customer-generators.
- Inadequate interruptible standby service option. Although the standby tariff allows the customer to purchase Non-Reserved Service, which functions in a similar manner to interruptible service, EAI retains the discretion to deny a customer's request for this service. This means that the SSR tariff does not guarantee a customer's ability to purchase interruptible standby service. Also, it appears that if a customer purchases Non-Reserved Service for a scheduled outage, the customer pays the demand charges on the supplemental rate as opposed to the daily maintenance service demand charges contained in the SSR.
- **Inadequate flexibility.** EAI's standby tariff does not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch, competitive market purchases, or special contracts.

Possible remedies for these issues are set forth below.

Potential Modifications to Standby Tariff

Following are suggested modifications to EAI's SSR tariff:

1. The SSR reservation demand charge should be unbundled into generation, transmission, and distribution components. The SSR tariff bundles these cost components into one reservation demand charge, making it difficult to assess the level of generation, transmission, and distribution costs that a standby customer is paying through the reservation charge. Unbundling these cost components would make the reservation charge more transparent. In addition, unbundling these costs would allow EAI to better reflect load diversity in the design of the demand charges for shared distribution and transmission facilities, as further discussed in recommendation number 9.

- 2. The unbundled generation component of the reservation demand charge for standby service should be set such that it is equivalent to the best FOR exhibited by any generating unit on EAI's system. This standby generation charge can be calculated by multiplying this best FOR by the demand charge in the customer's otherwise applicable full-requirements tariff.
- **3. The reservation demand charge should be differentiated by season.** Currently the reservation demand charge is a flat \$/kW-month for the entire year. However, all of the demand charges on supplemental rate schedules LGS and LPS are seasonal. The energy charges in the SSR are also seasonal. Thus, introducing seasonality into the design of the reservation demand charge would ensure consistency with the design of other rate components in EAI's tariff. This rate design modification would also more accurately reflect the seasonal variations in EAI's cost of service.
- 4. The daily maintenance and backup demand charges should apply only during on-peak periods. The SSR tariff defines on-peak hours for the Summer Period as 1 p.m. to 8 p.m. Monday through Friday. For the Other Period, on-peak hours are 7 a.m. to 6 p.m. Monday through Friday. The SSR tariff should be modified to specify that backup and maintenance demand charges would apply only during these on-peak hours. This would send an appropriate price signal to customers that would discourage them from imposing demands on EAI's system during times when EAI's generation reserve margins are at their tightest levels. Also, from a maintenance standpoint, customers can more effectively schedule their unit maintenance outages when demand charges are only imposed during the on-peak periods. (Of course, customers must notify EAI of any maintenance outage in advance.) Furthermore, demand charges that reflect time of use would be consistent with the requirement that maintenance service in the Summer Period be taken only during off-peak hours.



- 5. The daily backup and maintenance energy charges should be further differentiated on a time-of-use basis. In addition to the existing seasonal variation in these energy charges, the standby tariff should separate backup and maintenance energy charges for on-peak and off-peak hours. This modification would ensure that backup and maintenance energy charges more closely track EAI's incremental cost to provide energy to standby customers.
- 6. Customer-generators should have the option to buy backup power from the market through the utility and thereby avoid the monthly reservation charge for standby generation service. Under this approach, the standby customer would purchase backup energy from the utility only on an as-needed basis. Such purchases would be priced at the real time locational market price applicable to the geographic location at which the customer takes service. In addition, the customer would pay a share of any contracted capacity purchased, an allocated portion of transmission costs and ancillary services, and a small administrative fee to cover the utility's procurement cost.
- 7. Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load within a required timeframe to mitigate all or a portion of backup demand charges. This approach would establish the standby customer's generation reservation demand charge as a function of the load that the utility would be required to meet through standby service. This standby service amount would be less than the rated output of the customer's self-generating unit because it would incorporate an adjustment for the amount of load reduction that the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all or a portion of its standby needs. The utility would retain the discretion to approve each standby customer's load reduction plan, including whether the customer can shed load with a sufficient response time that would allow the utility to avoid generation reserve costs in accordance with the utility's applicable reliability criteria.
- 8. The Non-Reserved Service feature of the SSR tariff should be modified to facilitate the provision of interruptible standby service. EAI essentially offers a full interruptible option

through the Non Reserved Service provisions of the SSR. However, this service does not guarantee the provision of standby energy to support a maintenance outage. Even if such an outage is scheduled, the customer is required to pay significantly higher demand charges than would be incurred for a traditional maintenance outage under the tariff. The Non-Reserved Service provisions should be modified to include reasonable charges for maintenance outages and a requirement that such outages be scheduled at a mutually agreeable time for EAI and the customer.

- 9. Standby charges for shared transmission and distribution facilities should reflect the load diversity of CHP customers. The rates for shared transmission and distribution facilities, such as substations and primary feeders, should reflect load diversity. Load diversity recognizes that, except for facilities dedicated to a specific customer, the transmission and distribution system is not specifically designed to meet a single customer's needs, but is instead designed to serve the coincident peak demand by a pool of customers. Load diversity can be recognized by designing transmission and distribution demand charges on a coincident peak demand basis or by assessing charges for shared transmission and distribution facilities based on the demand established by the standby customer only during on-peak hours.
- **10. Standby rate design should avoid demand ratchets.** Demand ratchets should not apply to EAI's charges to standby customers for shared distribution facilities. Instead, customer-generators should pay for non-dedicated distribution facilities only when they are actually purchasing backup or maintenance power in a particular month.
- **11. Standby tariffs should be concise and easily understandable.** Customers who may consider installing a cogeneration system will have a difficult time understanding all of the charges that they may pay under various circumstances with the standby tariff and riders that EAI has in place today. For example, the maintenance service provision of the SSR tariff requires that maintenance outages during the summer season be performed only during the off-peak period. However, the tariff also states that maintenance service during the summer months will not be scheduled for a continuous period of less than one day. The latter provision essentially requires the customer to perform maintenance



during the on-peak hours of the summer months, creating an internal conflict in the maintenance service provisions of the tariff.

12. Standby tariffs should specify the

circumstances under which special contracts may be warranted. Customers who have specific needs or operating conditions may require special contracts for standby power. EAI's standby tariffs should therefore contain provisions that would allow standby customers who demonstrate unique requirements to negotiate customer-specific standby service contracts with the utility. These customer specific contracts would be submitted to the Arkansas Public Service Commission for review and approval, subject to appropriate confidentiality restrictions that may be required to protect the customer's commercially sensitive information.

Economic Analysis of Standby Tariff

An economic analysis was performed to estimate the monthly costs incurred by EAI customers who have onsite generation under the SSR tariff. To calculate these costs, an economic model was developed that estimates the monthly costs for reservation, maintenance service, backup service, and supplemental power. See Attachment Arkansas 1 online for a detailed description of the model.

The economic analysis calculated costs for three customer load sizes with the following customer generation parameters:

1. Small Load

- a. Total Demand: 1,500 kW at 70-percent load factor b. Customer Generation Demand: 700 kW at
- 100-percent load factor c. Forced Outage Hours: 146
- c. Forced Outage Hours: 14
- d. Maintenance Hours: 73
- e. Supplemental Service on Rate Schedule LGS at Primary Voltage

2. Medium Load

- a. Total Demand: 6,000 kW at 80-percent load factor b. Customer Generation Demand: 4,000 kW at
- 100-percent load factor c. Forced Outage Hours: 73
- d. Maintenance Hours: 73
- e. Supplemental Service on Schedule LGS at primary voltage

3. Large Load

- a. Total Demand: 30,000 kW at 75-percent load factor
- b. Customer Generation Demand: 20,000 kW at 100-percent load factor

- c. Forced Outage (Backup Service) Hours: 37
- d. Maintenance Hours: 37
- e. Supplemental Service on Rate Schedule LPS at transmission voltage

Attachment Arkansas-2 summarizes SSR costs at the existing tariff rates for each representative customer using the BAI economic model. Note that a transmission-level customer could take service under Schedule LGS or Schedule LPS. BAI opted to model the transmissionlevel customer's costs assuming that service is taken under Schedule LPS, in order to ensure that both of EAI's supplemental service tariffs would be modeled in the study.

In addition, an economic analysis was performed to estimate the bill impacts of the suggested tariff improvements. The modeled tariff charges used to develop these bill impacts are not based on a formal original cost of service study. Rather, the authors relied on the charges in the current utility rate schedules, with adjustments based on the judgment of the study authors using the criteria appearing in the recommendations and Chapter 1. Following are the principal features of the modeled tariff charges:

- A generation reservation charge was developed to reflect the performance of the best generating unit. For purposes of this analysis, the reservation charge was assumed to be five percent of the applicable generation and transmission demand charges, as the current SSR tariff charges are not unbundled.
- 2. A daily backup demand charge for power purchased during a forced outage was developed. If the selfgenerating unit was out of service for a full month, the charges would be equivalent to the applicable full requirements tariff.
- 3. The daily maintenance demand charges were set at 50 percent of the backup charges. The maintenance costs represent a discount from the daily backup demand charges because maintenance outages must be pre-scheduled with the utility during time periods when the utility's marginal cost of service is low. The current SSR maintenance daily demand charges are approximately 44 percent of the current daily backup demand charges. Therefore, this assumption is consistent with the SSR tariff.
- 4. The distribution rates were adjusted to reflect load diversity. The distribution component of the reservation charge was adjusted to include only an estimate of costs associated with dedicated distribution facilities. The non-dedicated



distribution costs were recovered through the daily demand charges described earlier. Because the current charges are bundled and no distinct distribution charges are available, the distribution component of the reservation charge was estimated by the study authors.

Attachment Arkansas 3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges relative to the modified charges. The calculations in this attachment exclude all energyrelated costs associated with purchases of fuel and supplemental power. With the exception of the VAR, the calculations also exclude costs associated with utility riders because they represent a small portion of the total cost of providing service to the customer, and none of the standby tariff modifications proposed in this study affect the excluded riders. The VAR was used to develop separate primary and transmission charges.

As Attachment Arkansas-3 shows, adjustments made to the reservation charges in the SSR tariff and the various supplemental rates to reflect the performance of the best self-generating unit on the utility system and load diversity result in reduced charges for the three load scenarios studied. The revised reservation charges are estimates; they were not developed from any cost of service study. Because rates are not unbundled, the authors used their judgment to estimate a breakdown of the generation, transmission, and distribution components of the reservation charges.

Adjustments also were made to reflect the recommendation to apply backup and maintenance charges only to demands that occur during on-peak weekday hours. As a result, the cost of providing standby service must be recovered over an approximate 20day period as opposed to a 30 day period, increasing the per-unit charge relative to the current SSR tariff. Backup and maintenance charges were further adjusted to recognize load diversity and to capture transmission and distribution costs that are not recovered through the modified reservation charge.

An analysis was performed showing customer savings for the Summer Period resulting from taking both backup and maintenance service only during the *off*-peak period. These savings result from applying backup and maintenance demand charges only during on-peak hours.

Customers who impose demands for backup or maintenance service during on-peak periods will incur higher costs under our simulation of modified SSR charges. This is because the backup and maintenance charges must be increased relative to the current tariff charges to reflect the fact that cost recovery will occur only during the on-peak period.

Our analysis does not reflect savings and costs associated with implementing our recommended timeof-day energy prices. The results would have been similar to the results discussed earlier for time of day demand charges. That is, energy usage during the off-peak periods would produce savings, while on-peak energy usage would increase costs.

It is important to note that customers taking standby service on an interruptible basis would avoid both the utility's standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions. For example, a transmission customer would pay all of the charges in EAI's LPS tariff.



Chapter 4. Colorado

Standby Rates for Customers of Public Service Company of Colorado

Description of Standby Rates

ublic Service of Colorado (PSCo) provides Transmission Standby Service under Schedule TST and Primary Standby Service under Schedule PST. The tariffs are for commercial and industrial customers who operate generating equipment in parallel with the utility's electric system and require 10 kW or more of standby capacity service.

Standby service charges include monthly reservation fees, including a Service and Facility Charge, an Interconnection Charge, a Generation and Transmission Standby Capacity Reservation Fee, and a Distribution Standby Capacity Fee. In addition, the standby tariffs include a usage charge for demand and energy. The demand charge is only applicable after the customer has used the allowed Grace Energy Hours for standby service, set at 1,051 hours.

The customer's standby contract capacity is set forth in a standby service agreement. The quantity of standby capacity can be set at different levels for the summer and winter seasons.

For customers who have a standby contract capacity ranging from 10 to 10,000 kW, maintenance on the generating unit must occur during the calendar months of April, May, October, or November. Customers must provide PSCo with written notice of scheduled maintenance prior to the beginning of the maintenance period.

Customers who have a standby contract capacity greater than 10,000 kW must provide to the utility an annual projection of scheduled maintenance. PSCo must authorize the schedule in advance. The amount of advance notice that the customer must provide depends on the expected duration of the maintenance outage. For example, if a customer requests an outage longer than 30 days, the required notice is 90 days. Maintenance outages cannot exceed six weeks in any 12-month period. Qualified scheduled maintenance time does not count against the customer's Grace Energy Hours.

Description of Rate Components

Schedules TST and PST contain the following rate components:

- 1. A monthly Reservation Fee consisting of a Service Charge and a Facilities Charge;
- An Interconnection Charge (only applicable to Schedule TST);
- 3. A Generation and Transmission Standby Capacity Reservation Fee; and
- 4. A Distribution Standby Capacity Fee (only applicable to Schedule PST).

For Schedule TST, the Service and Facilities Charge and Interconnection Charge are customer specific. In the case of Schedule PST, the Service and Facilities Charge is fixed for all customers at \$305 per month, and no Interconnection Charge applies.

The Generation and Transmission Standby Capacity Fee covers capacity costs up to the allowed Grace Energy Hours for standby service (1,051 hours), assuming a 100-percent capacity factor for the customer's generating unit, for an annual period that begins October 1. The annual Grace Energy consumed by the customer under the tariff is equal to the customer's standby service hours multiplied by the customer's standby contract capacity. If the customer exceeds the annual allowed Grace Energy Hours, the customer is billed for any used capacity related to a forced outage of its generating unit at a demand charge that is approximately equivalent to the demand charge the customer would pay on the applicable supplemental (full-requirements) tariff. The standby tariffs also include an energy usage charge.

Assessment of PSCo's Standby Rates

PSCo's standby tariffs lack adequate price signals that could provide incentives to standby customers to improve the operation of their generating units or to make more efficient use of local utility resources. For example, the tariffs do not incorporate daily generation demand charges that would give standby customers an incentive to reduce the duration of their generating unit outages.



The generation reservation charges also lack time-of-use price signals that would encourage customers to shift their use of the utility's resources to off-peak periods.

In addition, the design of PSCo's standby charges fails to recognize load diversity, resulting in rates that send inaccurate price signals to customers regarding the cost drivers behind the utility's investments. Furthermore, PSCo's standby rates lack price transparency because the generation and transmission costs are bundled together in the Reservation Fee component of the tariff.

Finally, PSCo's tariffs do not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as selfdispatch and the purchase of market-priced power.

Possible remedies for these issues are set forth below.

Potential Modifications to PSCo's Standby Tariffs

Following are suggested modifications to PSCo's standby tariffs for consideration:

- 1. The monthly standby charge (Reservation Fee for Generation and Transmission Capacity) should be set such that it is equivalent to the best FOR exhibited by any generating unit on PSCo's system. This standby generation charge can be calculated by multiplying this best FOR by the demand charge in the customer's otherwise applicable full requirements tariff. For example, the Summer period demand charge in Schedule TG for a transmission voltage level customer is \$9.68 per kW. Multiplying this charge by a FOR of five percent produces a Generation and Transmission Reservation Fee of \$0.484 per kW for the summer months.
- 2. Daily standby generation demand charges should be assessed to provide incentives to improve the performance of self-generating units. In addition to the Generation and Transmission Capacity Reservation Fee, standby customers should pay daily demand charges when they actually take backup power from the utility. To calculate a daily demand charge, divide the demand charge specified in the appropriate full-requirements tariff, adjusted to exclude the standby portion, by the average number of billing days in a month. Under this rate structure, the customer would pay the same amount as the supplemental rate if the customer took backup service for the entire month. The standby customer also would pay the utility's applicable fuel charges as well as all other applicable riders.

- 3. Customer-generators should have the option to buy backup power from the utility at market prices and thereby avoid monthly reservation charges for standby service. Under this approach, the standby customer would purchase backup energy from the utility on an as needed basis at wholesale market prices. In addition to these energy costs, the customer would pay a share of any capacity costs, an allocated portion of transmission costs and ancillary services, and a small administrative fee to cover the utility's costs for procurement.
- 4. Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (kW) within a required timeframe to mitigate all or a portion of backup demand charges. This approach would establish the standby customer's Reservation Fee as a function of the load that the utility would be required to meet through standby service. This standby service amount would be less than the rated output of the customer's generating unit because it would incorporate an adjustment for the amount of load reduction that the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all or a portion of its needs. The utility would retain the discretion to approve each customer's load reduction plan, including whether the customer can shed load with a sufficient response time to allow the utility to avoid generation reserve costs in accordance with applicable reliability criteria.
- 5. The generation and transmission cost components of the Reservation Fee should be unbundled. Under PSCo's current standby rate structure, it is difficult to assess the level of generation charges and transmission charges that a standby customer is paying in the Reservation Fee. This problem exists in both the standby tariffs and the supplemental tariff. Unbundling the generation and transmission cost components would make the rate design of the Reservation Fee more transparent.
- 6. Standby charges for shared distribution facilities should reflect load diversity. Customers should pay for the cost of distribution facilities that are dedicated entirely to serve an individual customer through the Reservation Fee. However, charges for shared distribution facilities such as substations and primary feeders should



reflect load diversity. Load diversity recognizes that a given portion of the distribution system is not specifically designed to meet a single customer's needs, but is instead designed to serve the coincident peak demand for distribution services that is established by a pool of customers. Load diversity can be recognized by designing the distribution demand charges on a coincident peak demand basis.

7. Standby backup demand charges for generation and distribution service should apply only during on-peak hours. This rate design would provide standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the cost of providing service is typically much lower. If PSCo's capacity costs are driven by customer demands established during defined on-peak periods, those same time periods should be used to establish the timeframe during which standby demand charges would be applicable.

Economic Analysis of Standby Tariffs

An economic analysis was performed to estimate the monthly costs incurred by PSCo customers who have on-site generation under Schedules PST and TST. To calculate these costs, an economic model was developed that estimates the monthly costs for reservation and supplemental power. Attachment Colorado 1, available online, describes the model in detail.

The economic analysis calculated costs for three load sizes and the following customer generation parameters:

1. Small Load

- a. Total Demand: 1,500 kW at 70-percent load factor
- b. Customer Generation Demand: 700 kW at 100-percent load factor
- c. Outage Hours: 40
- d. Supplemental Service on Schedule PG at primary voltage

2. Medium Load

- a. Total Demand: 6,000 kW at 80-percent load factor
- b. Customer Generation Demand: 4,000 kW at 100-percent load factor
- c. Outage Hours: 50
- d. Supplemental Service on Schedule PG at primary voltage

3. Large Load

- a. Total Demand: 30,000 kW at 75-percent load factor
- b. Customer Generation Demand: 20,000 kW at 100-percent load factor

- c. Outage Hours: 40
- d. Supplemental Service on Schedule TG at transmission voltage

Attachment Colorado-2 summarizes Schedule PST and TST costs at the existing tariff rates for each scenario using the BAI economic model.

In addition, BAI performed an economic analysis to estimate the bill impacts of the suggested tariff improvements. It should be noted that the modeled tariff charges used to develop these bill impacts are not based on a formal original cost of service study. Rather, the rate assumptions used in the economic model were developed by relying on the charges found in the current utility rate schedules, with appropriate adjustments based on the judgment of the study authors. The principal features of the modeled tariff charges include the following:

- A generation reservation charge was developed to reflect the performance of the best generating unit. For purposes of this analysis, the reservation charge was assumed to be five percent of the applicable generation and transmission demand charges.
- 2. A daily backup demand charge for power purchased during a forced outage was developed. If the selfgenerating unit was out of service for a full month, the cost would be equivalent to the cost incurred on the otherwise applicable full requirements tariff.
- 3. The distribution rates were adjusted to reflect load diversity. The distribution component of the reservation charge was adjusted to include only an estimate of costs associated with dedicated distribution facilities. The non-dedicated distribution costs were recovered through the daily demand charges described earlier. Because the current charges are bundled and no distinct distribution charges are available, the distribution component of the reservation charge was estimated by the study authors.

Attachment Colorado 3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges relative to the modified charges. The calculations exclude all costs associated with purchases of supplemental power. The calculations also exclude costs associated with all utility riders because none of the standby tariff modifications proposed in this study affect charges in the riders.

The adjustments to reservation charges to reflect the performance of the best self-generating unit on the utility's system and to reflect load diversity result in reduced reservation charges for the load scenarios



studied. The revised reservation charges are estimates; they were not developed from a cost-of-service study. Daily demand charges were created and modeled for each day where the model simulates a forced outage. Consistent with the current tariff, scheduled maintenance outages do not trigger demand charges.

In addition, the Grace Energy Hours provision was eliminated. The customer would simply incur daily demand charges for each day associated with an unscheduled outage.

The study authors did not have the data required to develop on-peak demand charges. Assuming that the utility's capacity needs and costs are driven by defined on-peak periods, demand charges should be applied only during on-peak periods.

Page 3 of Attachment Colorado-3 graphically compares

the cost associated with PSCo's current standby tariffs and the costs associated with the suggested revisions. The Primary Service scenario is applicable for Schedule PST and the Transmission Service scenario is applicable for Schedule TST. The attachment includes the assumptions used to develop the graphs.

Customers taking standby service on an interruptible basis would avoid both the standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions.



Chapter 5. New Jersey Standby Rates for Customers of Jersey Central Power & Light

Description of Standby Rates

ersey Central Power & Light offers a Standby Service Rider (STB) that is available to customers who have their own generating equipment. Rider STB is not available in any month in which the availability of the customer's generating unit does not exceed 50 percent. Rider STB is an abbreviated, but complex, standby tariff. The rider consists of a single Standby Demand Charge to recover the cost of distribution service provided by Jersey Central. The formula for the charge contains two equations, and the customer's monthly bill is based on whichever equation produces the greatest charge.

The first equation of the Standby Demand Charge is the sum of two charges:

- **Part A:** The Demand Rate (DR) per kW of the applicable service classification times the Billing Demand (BD) plus
- **Part B:** The Standby Rate (SR) per kW times the lesser of either the Maximum Monthly (MM) on-peak load of the facility or the annual Average Generation (AG) during the on-peak time periods

Part A of the equation reflects the cost of distribution service for supplemental power. BD is determined by subtracting AG on-peak from the customer's MM on-peak load of the facility. However, BD is never allowed to be less than zero. Consequently, if the customer's generation provides *less* than the facility's total load requirement (i.e., AG < MM), the BD represents the supplemental load necessary to serve the facility, priced at the applicable supplemental service demand charge. However, if the customer's generation is *greater* than what the facility requires (i.e., AG > MM), the BD is zero. In the latter situation, no supplemental service demand charge is assessed because the customer's own generation can supply 100 percent of the customer's load requirements.

Part B of the equation reflects the cost of distribution

service for standby service and is based on the lesser of MM on-peak load or AG. Thus, if the customer's own generation is less than the facility's total load requirement, the standby rate is assessed on the basis of AG. On the other hand, if the customer's generation capacity exceeds the facility's load requirements, the standby rate is assessed only on the customer's total on-peak load (MM).

The sum of the Part A and Part B charges is then compared to the results of the second equation of the Standby Demand Charge formula. The second equation is simply the Rider STB standby rate per kW times the Contract Demand (CD). The CD is the lesser of (1) the Capacity Rating of the generation facility, or (2) the greater of the MM facility on-peak load or the highest MM facility on-peak load during the most recent 12 months. For example, if the customer's own generation capacity is less than its MM facility on-peak load, this second equation will assess the standby charge based on the capacity rating of the generator. Alternatively, if the customer's generation is greater than what the facility requires, the standby rate is assessed based on the highest on-peak load of the facility over the most recent 12-month period.

A critical component of Rider STB is the determination of AG during on-peak times. Each month, AG is calculated and the most recent 12 months of AG are averaged for use in the monthly bill. To calculate the monthly AG, the customer's energy production during on-peak hours is divided by 260 hours (the full number of on-peak hours in each month) less any scheduled maintenance hours. However, the tariff provides that the scheduling of maintenance hours is permitted only for customers receiving service under Rider STB as of February 25, 1993.

The other caveat of Rider STB is that a customer's generating unit must have a FOR of less than 50 percent in order for the Rider to be available to the customer. If the customer's generation has an unscheduled outage that reduces its on-peak availability below 50 percent for the month, the customer's load for the month is served



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 29 of 118

Standby Rates for Combined Heat and Power Systems

under the otherwise applicable full-requirements service classification.

Assessment of Standby Rates

A general concern with Jersey Central's standby rates is that the rate design may be too complex. Simplicity and ease of understanding are commonly recognized as appropriate rate design goals.

Also, the generator availability factor limitation is restrictive. Similarly, the standby tariff appears to impose undue constraints on the ability of customers to schedule maintenance outages of their generating units. Easing these restrictions would make it easier for customers to install and operate on-site generation.

Possible remedies for these issues are set forth below.

Potential Modifications to Standby Tariff

Following are suggested modifications to Jersey Central's standby tariffs for consideration:

- Scheduled maintenance hours should be allowed for all standby customers. Under the current Rider STB, it appears that customers who commenced service under the rider after February 25, 1993 are not allowed to schedule maintenance for their generating units. The ability to schedule maintenance outages is critical for on-site generation.
- 2. Standby service should be available to all self-generating customers regardless of the availability factor of their generating units. Under the terms of Rider STB, any customer whose generation availability does not exceed 50 percent would default to the full requirements service tariff. The distribution demand charges in the full requirements tariffs are higher than the distribution charges in Rider STB. A more reasonable approach would be to structure Rider STB in a manner that gradually increases the cost of standby service as a standby customer's generation availability declines below 50 percent. Under this approach, the Rider STB demand charge would equal the fullrequirements service demand charge only when the availability factor of the customer's generation unit fell to zero.
- 3. Standby tariffs should be concise and easily understandable. Customers who may consider installing on-site generation systems could have a difficult time understanding the different types of demand measurements that could affect the level of

charges that they would pay under the STB Rider. The tariff could be simplified by imposing a set standby demand charge that assumes 100-percent availability of a customer's self-generating unit, accompanied by a daily demand charge that would recover the cost of backup distribution capacity purchased by the standby customer during forced outages and scheduled maintenance.

4. Standby charges for shared distribution facilities should reflect load diversity. The existing Rider STB voltage-level charges are likely below cost of service. The Rider STB voltage level charges are substantially less than the voltage level charges in the full requirements service tariffs. The difference in these rates indicates that the distribution charges for Rider STB were developed to encourage self-generation.

Economic Analysis of Standby Tariffs

An economic analysis was performed to estimate the monthly costs incurred by Jersey Central customers who have on-site generation under Rider STB. To calculate these costs, BAI developed an economic model that estimates the monthly costs for distribution energy charges, riders, and standby charges for Rider STB and the applicable service classifications (supplemental service). Attachment New Jersey 1, available online, describes the model in detail.

The model calculated costs for three load sizes and the following customer generation parameters:

1. Small Load

- a. Total Demand: 1,500 kW at 70-percent load factor
- b. Customer Generation Demand: 700 kW at 90-percent generator availability
- c. Maintenance Hours: 50
- d. Supplemental Service on Rate Schedule GP at primary voltage

2. Medium Load

- a. Total Demand: 6,000 kW at 80-percent load factor
- b. Customer Generation Demand: 4,000 kW at 85-percent generator availability
- c. Maintenance Hours: 60
- d. Supplemental Service on Schedule GT at high transmission voltage



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 30 of 118

Standby Rates for Combined Heat and Power Systems

3. Large Load

- a. Total Demand: 30,000 kW at 75-percent load factor
- b. Customer Generation Demand: 20,000 kW at 90-percent generator availability
- c. Maintenance Hours: 30
- d. Supplemental Service on Rate Schedule GT at transmission voltage

Attachment New Jersey-2 summarizes Rider STB costs at the existing tariff rates for each representative customer using BAI's economic model. The economic model did not include costs for generation service. Generation service for these customers is typically supplied by a third-party supplier, and including any cost estimate was deemed to be not necessary and speculative by the authors. In addition, an economic analysis was performed to estimate the bill impacts of the suggested tariff improvements described earlier. Modeled tariff charges used to develop these bill impacts are not based on a formal cost of service study. Rather, the rate assumptions used in the economic model were developed by relying on the charges in the current utility rate schedules, with adjustments based on the judgment of the study authors. The principal feature of the modeled tariff charge is making Rider STB available to all self-generating customers regardless of the availability of the generating unit in any month.

Attachment New Jersey 3 compares costs that would be incurred under the existing standby tariff charges compared to the modified charges. The calculations exclude costs associated with all other utility riders. None of the standby tariff modifications proposed in this study affects the excluded riders.



Chapter 6. Ohio Standby Rates for Customers of AEP Ohio

Description of Standby Rates

EP Ohio operates as Ohio Power Company in the state of Ohio. The utility has two rate zones: the Columbus Southern Power rate zone and the Ohio Power rate zone. Each of these rate zones has a standby tariff, Schedule SBS (Standby Service), applicable to customers who purchase power from Ohio Power Company. In addition, each rate zone has an open access standby tariff, Schedule OAD-SBS (Open Access Distribution Standby Service), which applies to customers who purchase power from a thirdparty supplier.

The standby tariff schedules and associated riders in each of the rate zones are identical except for the level of the charges. In addition, the terms and conditions for the provision of distribution service are the same for both Schedule SBS and Schedule OAD SBS. As a result, it is only necessary to address the terms and conditions of the tariffs for a single rate zone.

It is anticipated that by the end of 2015 all AEP Ohio Power Company customers will be able to choose a Certified Retail Electric Service (CRES) provider. Schedule OAD-SBS will apply to distribution-only customers who take service from a CRES provider. Schedule SBS will apply to distribution and Standard Service Offer (SSO) customers – those who do not take service from a CRES provider. SSO customers will pay energy prices based on the results of a competitive bidding process (an energyonly auction).

SCHEDULE SBS – STANDBY POWER SUPPLIED BY OHIO POWER COMPANY

Schedule SBS is available to customers who have an on-site source of electric energy supply and a standby generation supply requirement of 50,000 kW or less. The standby contract capacity in kW is initially established by mutual agreement between the customer and the utility.

The standby customer pays a demand charge for generation that is a function of the FOR and the supply

voltage. The utility offers a choice of six specified FORs (5, 10, 15, 20, 25, and 30 percent), with higher outage rates corresponding to higher generation demand charges. The customer can purchase backup power for a designated number of hours per year. The number of hours for which backup power is purchased varies as a function of the outage rate that the customer selects. If the customer requires backup power in excess of the designated hours during the control year, the customer defaults to the applicable full service tariff for the rest of the contract period.

For example, a primary voltage customer in the Columbus Southern Power Rate Zone who estimates a FOR of 15 percent will pay a monthly generation charge of \$2.455/kW,¹⁴ regardless of whether the customer actually buys backup power. The monthly generation charge allows the customer to buy back up energy for up to 1,314 hours (15 percent of 8,760 hours) during the year. When the customer exceeds the allowed outage hours, the customer is billed under the appropriate supplemental rate schedule. In that instance the monthly generation demand charge increases significantly and can become \$9.662/kW¹⁵ (Schedule GS-3, Primary Voltage).

In addition to the generation charges discussed earlier, the customer pays a monthly distribution standby charge that is a function of the customer's voltage level of service. The distribution charge is assessed on a \$/kW basis and recovers secondary and primary voltage level distribution costs. The distribution charges are not a function of the FOR and are the same for each FOR by voltage level (secondary and primary).

¹⁵ The charge increased to \$10.511/kW in September 2012.



¹⁴ Tariff rate in place at the time of BAI's economic analysis. In September 2012, the charge increased to \$2.671/kW.

Subtransmission and transmission costs that are incurred to serve standby customers are recovered through a Transmission Cost Recovery Rider. This rider allows the customer to purchase subtransmission/ transmission service for a set number of hours based on the selected FOR. The rider rate design is structured in the same manner as the generation demand charges described previously.

In the Columbus Southern Power Rate Zone, generation and transmission charges are the same for sub transmission and transmission customers. In the Ohio Power Rate Zone, there are separate generation charges for sub transmission and transmission customers, but the transmission rider charges are the same for both voltage levels.

SCHEDULE OAD-SBS – POWER SUPPLIED BY A THIRD PARTY

Schedule OAD-SBS is available to customers who have an on-site source of electric energy supply and a standby distribution requirement of 50,000 kW or less. The standby contract capacity in kW is initially established by mutual agreement between the customer and the utility.

Under this tariff schedule, the customer pays the monthly distribution standby charge that is applicable to Schedule SBS customers (described previously). Schedule OAD-SBS customers taking transmission service do so under the terms and conditions of the applicable open access transmission tariff (OATT), as filed with and accepted by the Federal Energy Regulatory Commission (FERC).

Assessment of Standby Rates

A central concern with AEP Ohio's standby rates is the design of the generation and transmission demand charges. Specifically the demand charge, with its menu of FORs, is complex and places substantial risk on the standby customer to accurately forecast its generating unit outage rate. The risk to the customer is created primarily by the fact that under forecasting the actual unit outage rate can lead to a substantial cost penalty when the customer is billed under the applicable supplemental rate schedule. At the same time, over forecasting actual unit performance forces the customer to pay generation and transmission demand charges in excess of the amount actually required to back up the customer's generating unit in a given year.

AEP Ohio's standby tariffs also lack adequate price signals that could provide incentives to standby customers to improve the operation of their own generating units or to make more efficient use of local utility resources. For example, the tariffs do not incorporate daily generation demand charges that would give standby customers an incentive to reduce the duration of their generating unit outages. In addition, the generation demand charges and fuel charges lack time-ofuse price signals that would encourage customers to shift their use of the utility's resources to off-peak periods that exhibit a lower marginal cost of service.

Furthermore, the standby charges for the use of AEP Ohio's shared distribution facilities fail to recognize load diversity.

Finally, AEP Ohio's standby tariffs do not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as self-dispatch, competitive market purchases, or special contracts.

Possible remedies for these issues are set forth below.

Potential Modifications to Standby Tariffs

Following are suggested modifications to AEP Ohio's standby tariffs for consideration:

- For customers who take standby generation service from the utility, the monthly backup charge (reservation demand charge) for standby generation service should be set such that it is equivalent to the best FOR exhibited by any generating unit on AEP Ohio's system. This standby generation charge can be calculated by multiplying the best FOR by the demand charge in the customer's otherwise applicable fullrequirements tariff. For example, using the demand charge in the Columbus Southern Power rate zone, General Service Medium Load Factor (Schedule GS 3) rate schedule, and an assumed FOR of 5 percent produces a monthly generation reservation charge of \$0.483/kW (0.05 x \$9.662/kW).¹⁶
- 2. Daily standby generation demand charges should be assessed to provide incentives to improve the performance of self-generating units. In addition to the reservation demand charge discussed previously, standby customers should pay daily demand charges when they actually take backup power from the utility. The daily demand charge is the demand charge as specified in the



¹⁶ In September 2012, the generation demand charges for Columbus Southern Power Rate Zone were modified as follows: Schedule GS-3 (secondary voltage) - \$10.867/kW, Schedule GS-3 (primary voltage) - \$10.511/kW.

appropriate full-service tariff adjusted to exclude the standby portion, divided by the average number of billing days in a month. When purchasing maintenance power, the daily demand charges should be reduced to reflect the scheduling of maintenance power when costs and systems stresses are low. The standby customer also should pay the utility's applicable fuel and purchased power charges as well as all other applicable riders.

- 3. Customer-generators should have the option to buy backup power from the market through the utility and thereby avoid the monthly reservation charge for standby generation **service.** Under this alternative approach, the standby customer would purchase backup energy from the utility only on an as-needed basis. Such purchases would be priced at the real time locational market price applicable to the geographic location at which the customer takes service. In addition, the customer would pay a share of any contracted capacity purchased, an allocated portion of transmission costs and ancillary services, and a small administrative fee to cover the utility's procurement cost if the power is purchased through the utility.
- 4. Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified kW amount of load within a required timeframe to mitigate all or a portion of backup demand charges. This alternative approach would establish the standby customer's generation reservation demand charge as a function of the load that the local utility would be required to meet through standby service. This standby service amount would be less than the rated output of the customer's self-generating unit because it would incorporate an adjustment for the amount of load reduction that the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all or a portion of its needs. The local utility would retain the discretion to approve each standby customer's load reduction plan, including whether the customer can shed load with a sufficient response time that would allow the utility to avoid generation reserve costs in accordance with the utility's applicable reliability criteria. This assumes that the utility is providing the backup service.
- 5. Standby charges for shared distribution facilities should reflect the load diversity of CHP customers. Under AEP Ohio's tariffs today, customer generators taking secondary or primary voltage level service pay the same distribution charges as full-requirements customers. This rate design is appropriate for distribution facilities dedicated entirely to serving the standby customer. However, charges for shared distribution facilities, such as substations and primary feeders, should reflect load diversity. Load diversity recognizes that a given portion of the distribution system is not specifically designed to meet a single customer's needs, but is instead designed to serve the coincident peak demand for distribution services that is established by a pool of customers. Load diversity can be recognized by designing the distribution demand charges on a coincident peak demand basis or by assessing charges for shared distribution facilities based on the demand established by the standby customer only during on-peak hours, as discussed below.

It should be noted that Ohio Power Company currently appears to reflect load diversity in its transmission service charges for standby customers. Specifically the customer generator pays for transmission service provided by the utility based on the selected FOR of the customer's generating unit.

- 6. Standby demand charges for generation and distribution service should apply only during on-peak hours. Ohio Power Company currently offers optional time-of-day schedules that assess demand charges based only on the peak demand established by the customer during on-peak hours. This provision could be applied to the determination of standby generation and distribution demand charges as well. This rate design would provide standby customers with an incentive to shift their use of the utility's assets to off-peak hours, when the marginal cost of providing service is typically much lower.
- 7. Standby rate design should avoid demand ratchets. For example, no demand ratchets should apply to AEP Ohio's charges to standby customers for shared distribution facilities. Instead customer-generators should pay for non-dedicated distribution facilities only when they are actually purchasing backup or maintenance power in a particular month. Any demand that a customer



generator imposes on the utility system in a given month should not be used to establish that customer's distribution or other demand charges for future months.

- 8. Standby tariffs should be concise and easily understandable. Customers who may consider installing a cogeneration system will have a difficult time understanding all of the charges they may pay under various circumstances with the standby tariffs and riders that AEP Ohio has in place today. To reduce the complexity of the standby tariffs, the Public Utilities Commission of Ohio may wish to consider replacing the existing menu of standby generation demand charges linked to various FOR levels with a single generation standby demand charge that is designed as a function of the best FOR among generating units on the utility's system.
- 9. Fuel and purchased power charges for standby customers should vary by time of use. Standby customers have some flexibility in the scheduling of maintenance outages of their generating units. If a customer purchases maintenance power, the economic choice may be to schedule such outages during time periods when the utility's incremental cost of fuel is low. By sending a price signal that more accurately reflects the utility's marginal fuel cost, time-of-use fuel charges can assist standby customers in efficiently scheduling maintenance outages of their generating units at times that would minimize the utility's cost of providing standby (maintenance) energy. The potential benefits of time-of-use fuel charges also would apply to full service customers who are capable of shifting load to low-cost periods.
- 10. Standby tariffs should specify the circumstances under which special contracts may be warranted. Customers who have standby power requirements in excess of 50,000 kW, as well as standby customers who have specific needs or operating conditions, may require special contracts for standby power. AEP Ohio's standby tariffs should therefore contain provisions that would allow standby customers who demonstrate unique requirements to negotiate customer-specific standby service contracts with the utility. These customerspecific contracts would be submitted to the Public Utilities Commission for review and approval, subject to appropriate confidentiality restrictions that may be required to protect the customer's commercially sensitive information.

Economic Analysis of Standby Tariffs

An economic analysis was performed to estimate the monthly costs incurred by Ohio Power Company customers who have on-site generation for both Schedule SBS and Schedule OAD SBS. To calculate these costs, an economic model was developed that estimates the monthly costs for standby, maintenance service, backup service, and supplemental power. Attachment Ohio-1, available online, describes the model in detail.

The economic analysis calculated costs for three load sizes for both the Columbus Southern rate zone and the Ohio Power rate zone. Following are the load sizes and customer generation parameters analyzed:

1. Small Load

- a. Total Demand: 1,500 kW at 70-percent load factor
- b. Customer Generation Demand: 700 kW at 100-percent load factor
- c. Forced Outage Hours: 146
- d. Maintenance Hours: 73
- e. Supplemental Service on Schedule GS-3 at Primary Voltage
- 2. Medium Load
 - a. Total Demand: 6,000 kW at 80-percent load factorb. Customer Generation Demand: 4,000 kW at
 - 100-percent load factor
 - c. Forced Outage Hours: 73
 - d. Maintenance Hours: 73
 - e. Supplemental Service on Schedule GS-3 at Primary Voltage

3. Large Load

- a. Total Demand: 30,000 kW at 75-percent load factor
- b. Customer Generation Demand: 20,000 kW at 100-percent load factor
- c. Forced Outage (Backup Service) Hours: 37
- d. Maintenance Hours: 37
- e. Supplemental Service on Schedule GS-4 at Transmission Voltage for the Columbus Southern rate zone and Schedule GS-3 for the Ohio Power rate zone

Attachment Ohio-2 summarizes costs at the existing tariffs for each rate zone. A comparison should not be made between the full service costs and the open access costs, because the market energy costs used for the open access tariff analysis do not incorporate all of the cost components that a customer may actually incur. BAI used historic market prices to simulate the cost of competitive



market purchases.

In addition, an economic analysis was performed to estimate the bill impacts of the suggested tariff improvements described previously. Modeled tariff charges used to develop these bill impacts are not based on a formal cost-of-service study. Rather, the rate assumptions used in the economic model were developed by relying on the charges found in the current utility rate schedules and the transmission rider, with appropriate adjustments based on the judgment of the study authors. The modeled tariff charges included the following:

- A generation reservation charge was developed to reflect the performance of the best generating unit on the utility's system. The reservation charge was assumed to be five percent of the applicable generation demand charge as specified in an appropriate supplemental tariff. Because we propose a uniform reservation charge for all customer generators, the model does not select a forecasted FOR.
- 2. A daily backup demand charge for power purchased during forced outages was developed by prorating the generation demand charge in the fullrequirements tariff. If the self-generating unit was out of service for a full month, the charges would be equivalent to the applicable full service tariff.
- 3. The daily maintenance demand charges were set at 50 percent of the backup charges. The maintenance costs represent a discount from the daily backup demand charges because maintenance outages must be prescheduled with the utility during periods when the utility's marginal cost of service is low. A 50-percent discount factor was therefore applied to the backup charges to recognize the lower cost of service associated with maintenance power.
- 4. The distribution rates were adjusted to reflect load diversity. First, the distribution reservation charge was adjusted to include only the costs associated with dedicated distribution facilities. The non-dedicated distribution costs were recovered through the daily demand charges described earlier. Second, the standby distribution reservation charges contained in the standby tariffs for each rate zone were reduced by 20 percent to estimate the dedicated distribution charge.

Attachment Ohio-3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges and the proposed modifications. For Schedule SBS, only changes in standby tariff and transmission charges are shown. The calculations exclude all energy-related costs associated with purchases of fuel, supplemental power, and power purchased from competitive electricity suppliers. With the exception of the transmission rider, the calculations also exclude costs associated with all utility riders. These rider costs were excluded from the analysis because they represent a small portion of the total cost of providing service to the customer. Moreover, none of the standby tariff modifications proposed in this study affects these rider charges.

Attachment Ohio-3, page 1, shows the results of the economic analysis for the Columbus Southern rate zone for Schedule SBS. Page 2 of the same attachment shows the results of the economic analysis for rate Schedule SBS for the Ohio Power rate zone.

The analysis for both of the rate zones indicates a slight reduction in cost for the suggested modifications for small load and medium load customers. The economic analysis for the large load indicates an increase in the cost associated with the modifications to Schedule SBS.

However, the small and medium load economic analyses model a worst-case scenario. That is, for each FOR, the maximum backup energy and arguably the maximum number of backup days were selected.

For example, for the small load the model assumes that the customer selected a FOR of 20 percent under the existing standby tariff rate design. This assumption implies that backup power would be needed for seven days [(730 hours x 20%) / 24] and the amount of backup energy would be 102,200 kWh (700 kW x 730 x 20%). This reflects the maximum amount of backup energy required and likely the maximum backup days. It is highly unlikely that a customer would pick a FOR assuming charges for the maximum amount of backup hours and backup energy. Of note, if the customer exceeds during the year the maximum specified hours for backup power, the customer will default to the supplemental rate. For the small load example, this would increase the generation charge to approximately \$9.662 per kW. This is an increase from the \$3.171 per kW that the customer is currently paying.

In addition, by defaulting to the supplemental rate, the transmission cost would increase from \$0.50 per kW to \$2.005 per kW. Because of the significant penalties involved, it is highly likely that the customer would overforecast the FOR for its generating unit.

This is significant because the analysis shows that under the current Schedule SBS the customer incurs the bulk of its charges through standby demand charges that the customer must pay each month, regardless of actual

use of standby service. However, when the tariff schedule is modified to incorporate the rate changes recommended in this study, a significant portion of the charges are incurred through the daily demand charges, which are assessed only when backup or maintenance power is actually purchased by the customer.

For the large load customer, the analysis is affected by the selected FOR under the existing standby tariff charges. Had a higher FOR such as 20 percent been selected, the economic analysis would have indicated that the tariff modifications proposed in this study would result in lower costs to the customer. Finally, it should be noted that Schedule SBS may cease to exist by the end of 2015, as Ohio Power Company is expected to transition to full open access at that time.

In addition to the economic analysis for Schedule SBS discussed earlier, the study also provides an analysis that compares the economic impact of the current Schedule OAD-SBS tariffs to the tariff charges that would result from the rate modifications proposed in this study. In this instance, only the distribution charge changes. For Schedule OAD SBS, the only suggested revision is to reflect load diversity in the distribution reservation demand charges. As discussed earlier in this chapter, this rate modification is appropriate because the distribution reservation demand charges should only reflect the cost of those facilities that are dedicated to serve the customer. As was the case in the analysis of the Schedule SBS rates, this tariff modification was reflected in the tariff charges by reducing the distribution costs by 20 percent. This adjusted portion of the distribution costs was then added to the daily demand charge that is paid when the

customer purchases backup or maintenance power.

Under Schedule OAD-SBS, the customer purchases maintenance power not from Ohio Power Company but through a third-party supplier. This largely eliminates the utility cost savings that could be realized by scheduling maintenance power during off-peak periods. For this reason, the study assumes that the charges for backup and maintenance distribution service would be identical under this schedule.

Attachment Ohio-4 shows that the tariff modifications proposed in this study would result in lower Schedule OAD-SBS costs in each of the rate zones for both the small and medium loads. The large load customer would incur no distribution costs because it is assumed that this customer purchases power at a transmission voltage level delivery point. The large customer would be securing standby generation from the competitive market and procuring transmission service under the applicable FERC OATT. Consequently the tariff modifications proposed in this study would have no impact on the cost of standby service for the large customer.

It is important to note that customers taking standby service on an interruptible basis would avoid both the utility's standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions.


Chapter 7. Utah

Standby Rates for Customers of Rocky Mountain Power

Description of Standby Rates

ocky Mountain Power (RMP) offers standby service on Schedule 31 to customers who use their own generating equipment on a regular basis. Total backup and maintenance power taken by the customer under Schedule 31 cannot exceed 10,000 kW. The schedule contains rates, terms, and conditions for the provision of backup power, maintenance power, and excess power:

- Backup power is the electric energy and capacity supplied by RMP during an unscheduled outage of the customer's electric generating equipment. The backup demand is measured only during the on-peak hours, 7 a.m. to 11 p.m. Monday through Friday, except designated holidays and days when generator maintenance is scheduled. All energy is priced under the provisions of the applicable general service schedule.
- 2. Maintenance power is the electric energy and capacity supplied by RMP during scheduled outages of the customer's generating equipment. For customers who have a peak demand in excess of 1,000 kW, the customer must submit a proposed maintenance schedule for each month of an 18-month period. The customer can schedule maintenance for a maximum of 30 days per year. The 30 days may be taken in either one continuous period or two continuous 15-day periods.
- 3. Excess power is the power that RMP supplies to the customer in excess of the total contract demand. The total contract demand is defined as the sum of the supplementary contract demand and the backup contract demand. Supplemental power is billed and priced pursuant to the provisions of the applicable general service schedule.

Description of Rate Components

Schedule 31 contains four charges that vary by voltage level (secondary, primary, and transmission):

- 1. Monthly customer charges
- 2. Facilities charges
- Daily on-peak backup power charges the daily maintenance power charges are set at one-half of the backup power on-peak charges
- 4. Excess power charges

Schedule 31 does not contain a generation reservation charge. The facilities charges apply to the kW of backup contract demand and are designed to recover the cost of distribution and transmission facilities.

The backup power charges apply only during the onpeak time periods designated in Schedule 31. No backup power charges are assessed to customers during off-peak hours. All backup and maintenance energy used by the customer is billed under the pricing provisions of the applicable general service schedule.

The excess power charges in Schedule 31 are set at approximately \$40 per kW for primary and transmission voltage customers. The excess power charges apply only to demand that exceeds the total contract demand. These charges are intended to provide customers with an incentive to accurately designate their backup contract demand and supplemental power demand.

Description of Rider Schedule 33

RMP also offers Generation Replacement Service (Schedule 33). Schedule 33 is available to customers who wish to curtail on-site generation and receive replacement power and energy from RMP. RMP offers the customer terms and conditions associated with the provision of generation replacement service at least five days in advance. The customer must respond to RMP's offer within 48 hours. If the offer is accepted, the customer then contracts for a specific amount of replacement power and energy at a designated price for the offer period. The customer must pay for the contracted amount of replacement power regardless of the customer's actual use of replacement service.



Assessment of Standby Rates

Schedule 31 facilities charges do not recognize load diversity in the use of RMP's shared transmission and distribution facilities.

In addition, Schedule 31 does not provide the standby customer with adequate flexibility to meet its standby requirements through alternative means such as selfdispatch, market-priced power purchases for backup power, or special contracts.

Potential Modifications to Standby Tariff

Following are suggested modifications to RMP's standby tariffs for consideration:

- 1. The on-peak, backup power charges should be stated on a seasonal basis. Although energy charges for supplemental-service rate schedules differentiate power charges for the summer and non-summer periods, backup power charges do not. The backup power charges should reflect higher rates during the summer period and lower rates during the non-summer period consistent with the supplemental power rates.
- 2. Customer-generators should have the option to buy backup power from the utility at market prices and thereby avoid the backup charge for standby generation service. Under this approach, the standby customer would purchase backup capacity and energy from the utility only on an as-needed basis. Such purchases would be priced at market prices at the appropriate trading hub. In addition, the customer would pay a share of any transmission and ancillary services costs, as well as a small administrative fee to cover the utility's procurement cost.

RMP's Energy Exchange Program Rider (Schedule 71) provides payments to participating customers at market-based prices for voluntarily reducing electricity consumption when called upon by the utility. The same data source for these hourly market prices could be used to price backup and maintenance energy under a market supply option for standby service.

3. Customer-generators should have the option to provide the utility with a load reduction plan that demonstrates their ability to reduce a specified amount of load (kW) within a required timeframe to mitigate all, or a portion of, backup demand charges. This approach would establish the standby customer's backup demand as a function of the load that the local utility would be required to meet through standby service. The standby service amount would be less than the rated output of the customer's selfgenerating unit because it would incorporate an adjustment for the amount of load reduction the customer can achieve. This option would give the standby customer the flexibility to use demand response to meet all, or a portion of, its needs. The utility would retain the discretion to approve each standby customer's load reduction plan, including whether the customer can shed load with a sufficient response time that would allow the utility to avoid generation costs in accordance with applicable reliability criteria.

- 4. Standby demand charges for shared transmission and distribution facilities should reflect the load diversity. The rates for shared transmission and distribution facilities, such as substations and primary feeders, should reflect load diversity. Load diversity recognizes that the transmission and a portion of the distribution systems are not specifically designed to meet a single customer's needs but are instead designed to serve the coincident peak demand for transmission and distribution services established by a pool of customers.
- **5. The cap for the provision of backup and maintenance service should be raised.** RMP's Schedule 31 restricts the provision of backup and maintenance power to loads that do not exceed 10,000 kW. A load cap may be needed to address concerns regarding the adequacy of the utility's generation reserves. However, the level of the cap is low and therefore unnecessarily restrictive.
- 6. Standby tariffs should specify the circumstances under which special contracts may be warranted. Customers who have specific needs or operating conditions may require special contracts for standby power. For example, RMP should be required to negotiate a special contract for the provision of standby service with any customer whose backup generation requirement exceeds the designated cap. RMP's standby tariffs should contain provisions that would allow standby customers who demonstrate unique requirements to negotiate customer-specific standby service contracts with the utility. These customer-specific contracts would be submitted to the Public Service Commission for review and approval, subject to appropriate confidentiality restrictions that may be required to protect the customer's commercially sensitive information.



7. The customer should be able to use the 30day allotment of maintenance power over more than two instances per year. Schedule 31 allows the standby customer to take maintenance power either in one continuous 30-day period or two continuous 15-day periods. Allowing more flexibility on the number of times a customer can take maintenance power would provide more opportunities to address generator reliability issues.

Economic Analysis of Potential Modifications

BAI performed an economic analysis to estimate the monthly costs incurred by RMP customers who have on-site generation under Schedule 31. BAI developed an economic model that estimates the monthly costs for reservation, maintenance service, backup service, and supplemental power. Attachment Utah 1, available online, describes the model results in detail.

The economic analysis calculated costs for three load sizes with the following customer generation parameters:

1. Small Load

- a. Total Demand: 4,350 kW at 75-percent load factor
- b. Customer Generation Demand: 1,950 kW at 100-percent load factor
- c. Forced Outage Hours: 48
- d. Maintenance Hours: 72
- e. Supplemental Service on Schedule Large General Service (Schedule 8) at Primary Voltage

2. Medium Load

- a. Total Demand: 19,500 kW at 80-percent load factor
- b. Customer Generation Demand: 7,500 kW at 100-percent load factor
- c. Forced Outage Hours: 48
- d. Maintenance Hours: 36
- e. Supplemental Service on Schedule General Service – High Voltage (Schedule 9) at Transmission Voltage

3. Large Load

- a. Total Demand: 25,000 kW at 80-percent load factor
- b. Customer Generation Demand: 25,000 kW at 80-percent load factor
- c. Forced Outage (Backup Service) Hours: 48
- d. Maintenance Hours: 48

 e. Supplemental Service on Schedule General Service – High Voltage (Schedule 9) at Transmission Voltage

Attachment Utah-2 summarizes Schedule 31 costs at the existing tariff rates for each representative load based on the output of the economic model.

In addition, BAI performed an economic analysis to estimate the bill impacts of the suggested tariff improvements described earlier in this chapter. Modeled tariff charges used to develop these bill impacts are not based on a formal cost of service study. Rather, the rate assumptions used in the economic model were developed based on charges in the current utility rate schedules, with adjustments based on the judgment of the study authors. The principal features of the modeled tariff charges include the following:

- 1. The on-peak backup power charges are stated on a seasonal basis, consistent with the power charges in the supplemental rate schedules.
- 2. A generation reservation charge was developed to reflect the performance of the best generating unit on the utility's system. For purposes of this analysis, the reservation charge was assumed to be five percent of the applicable generation and transmission demand charges.
- 3. The distribution rates were adjusted to reflect load diversity. The distribution component of the reservation charge was adjusted to include only an estimate of costs associated with dedicated distribution facilities. The non-dedicated distribution costs were recovered through the daily demand charges described earlier. Because the current charges are bundled and no distinct distribution charges are available, the distribution component of the reservation charge was estimated by the study authors.
- 4. The daily maintenance demand charges were set at 50 percent of the backup charges. The maintenance costs represent a discount from the daily backup demand charges because maintenance outages must be pre-scheduled with the utility during time periods when the utility's marginal cost of service is low.

Attachment Utah 3 compares the charges/rates and costs that would be incurred under the existing standby tariff charges and the modified charges. Page 1 of the attachment shows the current and proposed facilities and backup power charges for primary and transmission



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 40 of 118

Standby Rates for Combined Heat and Power Systems

voltage customers. The calculations used to develop the graphs on page 2 of the attachment exclude all energy-related supplemental power and rider costs.

As shown on Attachment Utah-3, BAI developed a backup power reservation charge to reflect the estimated performance of the best self-generating unit on the utility's system, and the facilities charges were revised to reflect load diversity. The charges are estimates and were not developed from a cost-of-service study.

Page 2 of Attachment Utah-3 shows that the creation of seasonal backup power charges result in higher costs during the summer months and lower costs in the winter months. In addition, the revised charges are lower because of the reduction to the facilities charges to reflect load diversity for shared transmission and distribution facilities.

It is important to note that customers taking standby service on an interruptible basis would avoid both the utility's standby reservation charges and backup charges associated with any unscheduled outages. (The customer would still be required to pay for any dedicated distribution facilities.) However, the customer would default to the full-requirements tariff, and pay the generation, transmission, and distribution charges in that tariff, if the customer is unable to interrupt its load in compliance with the standby tariff conditions.



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Attachments

Attachment Arkansas-1 Standby Rate Model Description

Attachment Arkansas-2 Costs at Existing Standby Rates

Attachment Arkansas-3 Cost Comparison of Existing Rates and Modified Rates

Attachment Arkansas-4 Standby Rate Model

Attachment Colorado-1 Standby Rate Model Description

Attachment Colorado-2 Costs at Existing Standby Rates

Attachment Colorado-3 Cost Comparison of Existing Rates and Modified Rates

Attachment Colorado-4 *Standby Rate Model*

Attachment New Jersey-1 Standby Rate Model Description

Attachment New Jersey-2 *Costs at Existing Standby Rates*

Attachment New Jersey-3 Cost Comparison of Existing Rates and Modified Rates

Attachment New Jersey-4 *Standby Rate Model* **Attachment Ohio-1** Standby Rate Model Description

Attachment Ohio-2 Costs at Existing Standby Rates

Attachment Ohio-3 Cost Comparison of Existing Rates and Modified Rates (Schedule SBS)

Attachment Ohio-4 Cost Comparison of Existing Rates and Modified Rates (Schedule OAD-SBS)

Attachment Ohio-5 *Standby Rate Model*

Attachment Utah-1 Standby Rate Model Description

Attachment Utah-2 Costs at Existing Standby Rates

Attachment Utah-3 Cost Comparison of Existing Rates and Modified Rates

Attachment Utah-4 Standby Rate Model



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 43 of 118



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Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 44 of 118



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Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 45 of 118

Attachment Arkansas-1 Page 1 of 3

Entergy Arkansas, Inc. <u>Standby Rate Model</u>

Brubaker and Associates, Inc. (BAI) has created a model that estimates the monthly charges incurred by an Entergy Arkansas, Inc. (EAI) customer utilizing on-site generation under Rate Schedule No. 20 Standby Service Rider (SSR) with Secondary, Primary, and Transmission level voltages analyzed. Supplemental power in excess of on-site generation is served under applicable standard tariffs. The three rate schedules analyzed in the model are: (1) Small General Service (SGS) at Secondary Voltage, (2) Large General Service (LGS) at Primary Voltage, and (3) Large Power Service (LPS) at Transmission Voltage. In addition, there are several riders that must be applied to each scenario.

The model requires the user to input six fields, either manually or from a drop down list:

- Season (choice of either Summer or Other Period);
- Customer's peak demand;
- Customer's load factor;
- Net capability of the on-site generator;
- Backup hours; and
- Maintenance outage hours.

Based on these user-provided inputs, the model determines the amount of energy and power to be charged in four separate categories: Reservation, Maintenance, Backup, and Supplemental.

The Reservation charge is the charge associated with the capacity that EAI must have available in case of either a forced outage (unscheduled) or a maintenance outage (scheduled) of the on-site generator. In the model, charges incurred in this category consist of the monthly customer charge, the monthly Reservation Charge based on the demand of the on-site generator, and other applicable riders.

Maintenance charges are the charges associated with the capacity and energy that EAI must provide for the duration of a planned outage. The customer must notify EAI at least seven days in advance of the planned maintenance, and may only perform such maintenance during specified periods of the year, as defined in the tariff. Maintenance service is available during the months of October through May and during the off-peak hours of the months of June through September. The costs related to maintenance are based on the demand of the on-site generator, a seasonal daily Maintenance Demand Charge, a seasonal Maintenance Energy Charge, and all other applicable riders.

Backup charges are the charges associated with demand and energy that EAI must provide during an unplanned outage. Backup Demand charges for a forced outage are greater than those of the Maintenance charges because of the unexpected nature of an unplanned outage. The costs related to forced outages are based on the demand of the on-site generator, a daily seasonal Backup Demand charge, a seasonal energy charge that is applied to the lost generation output, and other applicable riders. Backup energy is priced the same as Maintenance energy.

Supplemental charges cover the costs of electricity needed to fulfill the remainder of the customer load, i.e., the load less the on-site generation. Rates for supplemental usage are found in general Rate Schedule SGS, LGS, and LPS with costs for demand, energy, plus all applicable riders.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 46 of 118

Attachment Arkansas-1 Page 2 of 3

The model has a tab for each of the supplemental rate schedules. On each of these tabs, the charges for the four categories, identified above, are shown in both detail and summarized. Each category has the charges broken into four rate components: customer, demand, energy, and riders. These cost are then totaled, allowing for a per unit cost (\$/kWh) to be calculated for each category. The bottom left of each of the class tabs has the grand total of all charges. The Municipal Franchise Adjustment Rider costs are shown separately. This allows the user to input the specific town/city rate.

Instructions for Using the Model

- 1. On the inputs tab, fill in all of the orange boxes. The season input is a drop down menu, and the rest must be manually entered.
- 2. Make sure the file calculates. Press F9 if necessary.
- 3. The model will now have each of the rate schedule costs calculated for the inputs provided.
- 4. To evaluate various scenarios, alternative charges or rates will have to be inserted in the applicable rate "tab" which is discussed below.

Definition of Inputs

- Season The Summer Period is defined as the billing months of June, July, August, and September. All other billing months are defined as "Other Period."
- Peak Demand The maximum demand in kilowatts that is required to fulfill the customer's entire load.
- Load Factor The ratio of average demand to peak demand over a period of time. For this model, that period of time is 730 hours. Can be calculated as the average monthly energy for the season divided by the peak demand times 730 hours.
- Generator Net Capability The net capacity of the on-site generator in kilowatts. Generally, the nameplate capacity of the unit less any environmental adjustments.
- Forced Outage Hours The number of hours in the month in which the generator will be offline due to an unexpected outage. Must be less than 730 hours.
- **Maintenance Hours** The number of hours in the month in which the generator will be offline due to a planned outage. Must be less than 730 hours.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 47 of 118

Attachment Arkansas-1 Page 3 of 3

<u>Tabs</u>

The model has the following three other tabs:

- SGS: Contains charges for SSR, SGS, and the applicable riders. Displays the calculated costs for Reservation, Maintenance, Backup, and Supplemental capacity and energy.
- LGS: Contains charges for SSR, LGS, and the applicable riders. Displays the calculated costs for Reservation, Maintenance, Backup, and Supplemental capacity and energy.
- LPS: Contains charges for SSR, LPS, and the applicable riders. Displays the calculated costs for Reservation, Maintenance, Backup, and Supplemental capacity and energy.

The user views the costs on the appropriate tab.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 48 of 118

 Monthly Billing Units

 Total Demand
 1500 kW

 Supplemental Demand
 800 kW

 Baseload Demand
 700 kW

 Load Factor
 7000 %

 Supplemental Lead Factor
 7000 %

 Monthly Energy
 756.500 kWh

 Baseload Demand
 7000 %

 Baseload Energy
 755.500 kWh

 Baseload Energy
 357.700 kWh

 Baseload Energy
 51.100 kWh

 Markinsherane Duragion
 51.100 kWh

 Maker Duration
 7 Days

 Maintenance Duration
 4 Days

Note: Sum of Forced Outage Hours and Maintenance Outage Hours must be less than 730

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 49 of 118

412 9,648 8,750 8,750 5 13,146 5 31,956 0.07817

Customer Demand Energy Riders Total \$/KWh

		Large General Se Su	rvice at Primary nmer Period	r Voltage				
		Reserved to the second se	rvation Charges ts Rate	Charç	le Volt. Adj. Redu	ced Units Volt. Adj. Red	uced Rate Volt. Adj. Reduct	ed Charge
Total Reservation Charges Customer Demand Energy	\$ 412 \$ 1,337 \$ -	Customer Customer Dermand E nergy	1 \$ 700 \$ 357,700 \$	412.37 \$ 2.79 \$ - \$	412 1,953 -	1 \$ 693 \$ 354,123 \$	412.37 \$ 1.93 \$ - \$	412 1,337
Total Cost	\$ 1,736	Riders Capacity Acquisition Rider	1,750	-0.7656% \$	(13)			
		diaM P	enance Charges ts Rate	Charg	le Volt. Adj. Redu	ced Units Volt. Adj. Red	uced Rate Volt. Adj. Reduc	ed Charge
Total Maintenance Charges Demand Energy	\$ 275 \$ 1,094	Base Charges Demand Energy	2,800 \$ 51,100 \$	0.1275 \$ 0.02162 \$	357 1,105	2,772 \$ 50,589 \$	0.10 \$ 0.02162 \$	275 1,094
Total Cost	\$ 2,766	Riders Energy Cost Recovery Rider (\$/kWh)	51,100 \$	0.01783 \$	911	50,589 \$	0.01783 \$	902
S/k/Vh	\$ 0.05414	Energy Efficiency Cost Rate Rider (\$/k/Wh) Grand Gulf Rider (SGS energy, LGS & LPS Demand)	51,100 \$ 700 \$	0.00178 \$	- 91	50,589 \$ 693 \$	0.00178 \$	6.
		Federal Litigation Consulting Fee Rider (\$/kWh) Production Cost Allocation Rider (\$/kWh)	51,100 \$ 51,100 \$	0.00005 \$	3 289	50,589 \$ 50,589 \$	0.00005 \$	3 286
		Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	1,497 700 \$	-0.7656% \$ 0.18505 \$	(11) 130	693 \$	0.1851 \$	128
		- - -	ckup Charges ts Rate	Charç	le Volt. Adj. Redu	ced Units Volt. Adj. Red	uced Rate Volt. Adj. Reduce	ed Charge
Total Backup Charges Demand Energy	\$ 1,303 \$ 2,187	Base Charges Demand Energy	4,900 \$ 102,200 \$	0.297 \$ 0.02162 \$	1,455 2,210	4,851 \$ 101,178 \$	0.27 \$ 0.02162 \$	1,303 2,187
Riders Total Cost	\$ 2,662 \$ 6,153	Riders						
s/k/v/h	\$ 0.06021	Energy Cost Recovery Kider (\$KWN) Energy Efficiency Cost Rate Right (\$KWN) Control of the cost Rate Right (\$KWN)	102,200 \$ 102,200 \$	0.00178 \$	1,822 182	101,178 \$ 101,178 \$	0.00178 \$	1804
		orariu our ruser (305 errergy, LGS & LFS Derrariu) Federal Ligation Consulting Fee Rider (\$KVVh) Production Cost Allocation Rider (\$KVVh)	102,200 \$	0.00005 \$	- 5 578	101,178 \$ 101,178 \$	0.0005 \$	- 573
		Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	3,619 700 \$	-0.7656% \$ 0.18505 \$	(28) 130	693 \$	0.1851 \$	128
		Supp T	emental Charges ts Rate	Charg	le Volt. Adj. Redu	ced Units Volt. Adj. Red	uced Rate Volt. Adj. Reduce	ed Charge
Total Supplemental Charges Demand Energy Riders	\$ 6,732 \$ 5,469 \$ 7.797	Base Charges Demand Energy	800 \$ 255,500 \$	9.36 \$ 0.02162 \$	7,488 5,524	792 \$ 252,945 \$	8.50 \$ 0.02162 \$	6,732 5,469
Total Cost SkWh	\$ 19,997 \$ 0.07827	Riders Energy Cost Recovery Rider (\$KWh) Energy Efficiency Cost Bate Rider (\$KWh)	255,500 \$ 255,500 \$	0.01783 \$	4,556 455	252,945 \$ 252,945 \$	0.01783 \$	4,510 450
		Grand Gulf Rider (SGS energy, LGS & LPS Demand) Federal Litigation Consulting Fee Rider (\$KWh)	700 \$ 255,500 \$	1.96 \$ 0.00005 \$	1,372 13	693 \$ 252,945 \$	1.96 \$ 0.00005 \$	1,358 13
		Production Cost Allocation Kider (S/KWh) Capacity Acquisition Rider	12,329	0.00566 \$	1,446 (94)	252,945 \$	0.00566 \$	1,432
		Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700 \$	0.18505 \$	130	693 \$	0.1851 \$	128
			ichise Adjustment Rider ts Rate	Charg	9			
		reservation unarges Maintenance Charges Backup Charges	1, 7.30 2, 766 6, 153	4.250% \$ 4.250% \$	/4 118 262			
		Supplemental Charges	19,997	4.250% \$	850			

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 50 of 118

 Monthly Billing Units

 Total Demand
 1,500 kW

 Suppimental Demand
 900 kW

 Baseload Demand
 700 kW

 Baseload Demand
 700 kW

 Suppimental Load Factor
 700 kW

 Suppiemental Load Factor
 43.75 %

 Monthly Energy
 255.500 kWh

 Baseload Energy
 357.700 kWh

 Baseload Energy
 357.700 kWh

 Baseload Energy
 357.700 kWh

 Baskup Duration
 7 Days

 Maintenance Duration
 7 Days

Select Season From Drop Down Other Pendod Season From Drop Down Other Pendod Season From Drop Down Other Pendod Season From Other Pendod Season Ot

Note: Sum of Forced Outage Hours and Maintenance Outage Hours must be less than 730

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 51 of 118

		Ō	ther Period				
		ъ Т	nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Total Reservation Charges Customer Demand Energy	\$ 412 \$ 1,337 \$ -	Base Charges Customer Demand Energy	1 \$ 700 \$ 357,700 \$	412.37 \$ 41 2.79 \$ 1,95 - \$ -	1 3693 354,123	\$ 412.37 \$ 1.93 \$ -	\$ 412 \$ 1,337 \$
Riders Total Cost	\$ (13) \$ 1,736	Riders Capacity Acquisition Rider	1,750	-0.7656% \$ (1	3)		
		Main	tenance Charges Nts Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Total Maintenance Charges Demand Energy Riders	s 230 S 778 S 1.400	Base Charges Demand Energy	2,800 \$ 51,100 \$	0.1113 \$ 31 0.01538 \$ 78	2 2,772 16 50,589	\$ 0.08 \$ 0.01538	\$ 230 \$ 778
Total Cost S/KWh	\$ 2,409 \$ 0.04713	Riders Energy Cost Recovery Rider (\$MVh) Energy Efficiency Cost Rate Rider (\$MWh) Energy Efficiency Cost Rate Rider (\$MWh) Control Hindler (\$058 energy LOS & LDS Bennard) Control Hindler (\$058 energing Los & LDS Bennard)	51,100 \$ 51,100 \$ 700 \$	0.01783 \$ 91	11 50,589 11 50,589 693	\$ 0.01783 \$ 0.00178 \$	\$ 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8
		revent a Lugaroux Constanting reer work (%W/h) Production Cost Alexation Rider (%W/h) Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	51,100 \$ 1,136 700 \$	0.18505 \$ 28 0.18505 \$ 28 0.18505 \$ 13	50,589 (9) 50,589 693	\$ 0.00566 \$ 0.1851	\$ \$ 286 \$ 128
		1	ackup Charges its Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Total Backup Charges Demand Energy Riders	\$ 1,080 \$ 1,556 \$ 2,669	Base Charges Demand Energy	4,900 \$ 102,200 \$	0.251 \$ 1,23	30 4,851 2 101,178	\$ 0.22 \$ 0.01538	\$ 1,080
Total Cost SkWh	\$ 5,305 \$ 0.05191	Riders Erengy Cost Recovery Rider (\$KWh) Erengy Erleary Cost Rane Rater (\$KWh) Gand Oait Reier (SCS energy, LCS & LPS Demand) Federal Liggion Consoling; Fee Ricer (\$KWh) Debrau Liggion Consoling; Fee Ricer (\$KWh)	102,200 \$ 102,200 \$ 700 \$	0.01783 \$ 1,82 0.00178 \$ 1,82 0.00005 \$ -	22 101,178 32 101,178 693 693 101,178	\$ 0.01783 \$ 0.00178 \$ 0.00005	5 5 5 1,804
		Firouction Cost Aurodation Kriter (XKWT)) Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700 \$	0.18505 \$ 13 0.18505 \$ 13	21) 21) (01 00 (693	s 0.1851	s 5/3 \$ 128
		Supp. Un	lemental Charges vits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Total Supplemental Charges Demand Energy Riders	\$ 5,599 \$ 3,890 \$ 7,817	Base Charges Demand Energy	800 \$ 255,500 \$	7.93 \$ 6,34 0.01538 \$ 3,93	14 792 10 252,945	\$ 7.07 \$ 0.01538	\$ 5,599 3,890
Total Cost SkWh	\$ 17,307 \$ 0.06774	Riders Energy Cast Recovery Rider (\$KWh) Energy Efficiency Cost Rate Rider (\$WMh) Grand Guilf Rider (\$SSS enercy. LCS & LPS Demand)	255,500 \$ 255,500 \$ 700 \$	0.01783 \$ 4,55 0.00178 \$ 45 1.37	56 252,945 55 252,945 252,945 2633	\$ 0.01783 \$ 0.00178 \$	\$ 4,510 \$ 450 \$ 1.358
		Federal Litigation Consulting Fee Rider (\$KWh) Production Cost Albaction Rider (\$KWh) Capacity Acquisition Rider Storm Recovery Rider (\$SS Energy, LGS &LPS Demand)	255,500 \$ 255,500 \$ 9,618 700 \$	0.00005 \$ 1,44 0.00566 \$ 1,44 -0.7656% \$ (7 0.18505 \$ 13	13 252,945 46 252,945 44) 693	\$ 0.00005 \$ 0.00566 \$ 0.1851	s 1,432 s 1,432 s 1,28
		Municipal Fra	Inchise Adjustment Riden				
		Un Reservation Charges Maintenne Charges Badvup Charges Supplemental Charges	nits Rate 1, 736 2, 409 5, 305 17, 307	Charge 4.250% \$ 7 4.250% \$ 10 4.250% \$ 22 4.250% \$ 73	22 55 16		
			Total			ſ	

Large General Service at Primary Voltage

Customer Demand Energy Riders Total \$/KWh

412 8,247 6,224 13,011 27,895 0.06824

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 52 of 118

 Monthly Billing Units

 Cotal Demand
 6,000 KW

 Suppimeratal Demand
 6,000 KW

 Baseload Demand
 2,000 KW

 Baseload Demand
 4,000 KW

 Baseload Demand
 4,000 KW

 Suppimeratal Load Factor
 8,000 %

 Suppimeratal Lead
 3,504,000 KW

 Baseload Energy
 5,356,000 KW

 Basckup Energy
 2,336,000 KW

 Basckup Lenergy
 2,336,000 KW

 Basckup Urration
 4,0 ay

 Maintenance Ourage Energy
 2,320,000 KW

 Basckup Duration
 4,0 ay

	Inputs	
	Season	
Select Season From Drop Down	Summer Period	
	Load Characteristics	
Enter Peak Demand (kW)	6,000 kW	2
Enter Load Factor	80 %	
	Generator Characteristics	
Enter Net Capability (kW)	4,000 kW	2
Enter Backup Hours	73 Hour	ours
Enter Maintenace Hours	73 Hour	ours

Note: Sum of Forced Outage Hours and Maintenance Outage Hours must be less than 730

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 53 of 118

412 5 412 5 30,300 5 42,811 5 98,524 0.08435

Customer Demand Energy Riders Total \$/KWh

		Large General S ^u	ervice at Primar mmer Period	y Voltage			
		203 - C	ervation Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total Reservation Charges Customer Demand Energy	\$ 412 \$ 7,643 \$ -	Base Charges Customer Demand Energy	1 \$ 4,000 \$ 2,336,000 \$	412.37 \$ 2.79 \$ 1'	112 1412 3,960 1,160 3,960 - 2,312,640 -	1 \$ 412.37 0 \$ 1.93 0 \$ -	\$ 412 \$ 7,643 \$
Total Cost	\$ 7,993	Riders Capacity Acquisition Rider	8,055	-0.7656% \$	(62)		
		Matr U	itenance Charges hits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total Maintenance Charges Demand Energy Riders	\$ 1,571 \$ 6,250 \$ 7,987	Base Charges Demand E neigy	16,000 \$ 292,000 \$	0.1275 \$ 0.02162	,040 15,84(,313 289,08(0.10 0.10 0.10 0.02162	\$ 1,571 \$ 6,250
Total Cost SkWh	\$ 15,808 \$ 0.05414	Riders Energy Cost Recovery Rider (\$KWh) Energy Efficiency Cost Rate Rider (\$KWh)	292,000 \$ 292,000 \$	0.01783 \$,206 289,080 520 289,080	0.01783 0 \$ 0.00178	\$ 5,154 \$ 515
		Grand Gulf Rider (SGS energy, LGS & LPS Demand) Federal Litigation Consulting Fee Rider (\$kWh) Production Cost Allocation Rider (\$KWh)	4,000 \$ 292,000 \$ 292,000 \$	0.00005 \$ 0.00566 \$	- 3,96(15 289,08(653 289,080	0.00005 0 \$ 0.00005 0 \$ 0.00566	s s 1.636
		Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	8,554	-0.7656% \$ 0.18505 \$	(65) 740 3,960	0.1851	\$ 733
		<u>n</u> D 1 1	ackup Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Iotal backup Charges Demand Derregy	\$ 4,256 \$ 6,250	base Unarges Demand Energy	16,000 \$ 292,000 \$	0.297 \$ 0.02162 \$,752 15,840 (313 289,080	0.27 0.27 0.27 0.02162 0.02162	\$ 4,256 \$ 6,250
Riders Total Cost	\$ 7,966 \$ 18,472	Riders Enerov Cost Recovery Rider (SKWh)	292.000 \$	0.01783 \$	206 289.080	0.01783	S 5.154
\$/k/Vh	\$ 0.06326	Energy Efficiency Cost Rate Rider (\$/kWh) Grand Gulf Rider (SGS energy, LGS & LPS Demand)	292,000 \$ 4,000 \$	0.00178 \$	520 289,080 - 3,960	0.00178	\$ 515 \$
		Federal Litigation Consulting Fee Rider (S/kWh) Production Cost Allocation Rider (S/kWh)	292,000 \$ 292,000 \$	0.00005 \$	15 289,080 653 289,080	0.00005 0.000566 0.00566	\$ 14 \$ 1,636
		Capacity Acquisition Kider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	11,239 4,000 \$	-0.7656% \$ 0.18505 \$	(86) 740 3,960	0.1851	\$ 733
			lemental Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Iotal Supplemental Charges Demand Energy Riders	\$ 16,830 \$ 12,500 \$ 22 903	base Charges Demand Energy	2,000 \$ 584,000 \$	9.36 \$ 18 0.02162 \$ 12	,720 1,980 ,626 578,160	0 \$ 8.50 0 \$ 0.02162	\$ 16,830 \$ 12,500
Total Cost	\$ 52,233 \$ 0.08044	Riders Energy Cost Recovery Rider (\$/KWh) Enerword Fifricianov Crost Pate Brider (\$/WMh)	584,000 \$ 584,000 \$	0.01783 \$ 10	,413 578,160 040 578,180	0.01783	\$ 10,309
		Grand Guif Rider (SGS energy, LGS & LPS Demand) Federal Litigation Consulting Fee Rider (\$/kWh)	4,000 \$ 584,000 \$	0.00005 \$,840 3,960 29 578,160	0.00005 0.00005	\$ 7,762 \$ 29
		Production Cost Allocation Rider (\$/kWh) Capacity Acquisition Rider	584,000 \$ 30,063	0.00566 \$ 3	,305 578,160 (230)	0.00566	\$ 3,272
		Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000 \$	0.18505 \$	740 3,960	0.1851	\$ 733
		Municipal Fr U	anchise Adjustment Ride nits Rate	Charge			
		Reservation Charges Maintenance Charges Backup Charges	7,993 15,808 18,472	4.250% \$ 4.250% \$ 4.250% \$	340 672 785		
		Supplemental Charges	52,233	4.250% \$	220		

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 54 of 118

 Monthly Billing Units

 Total Demand
 6,000 kW

 Supplemental Demand
 6,000 kW

 Baseload Demand
 2,000 kW

 Baseload Demand
 4,000 kW

 Load Factor
 80.00 %

 Supplemental Lead Factor
 40.00 %

 Baseload Demand
 2,000 kW

 Baseload Energy
 3,504,000 %M

 Baseload Energy
 2,336,000 kW

 Baseload Energy
 2,336,000 kW

 Monthly Energy
 2,336,000 kW

 Masterbareneo Curgag Energy
 2,22,000 kW

 Maintenance Duration
 4 Bays

	Inputs	
	Season	
Select Season From Drop Down	Other Period	
	Load Characteristics	
Enter Peak Demand (kW)	6,000 kW	×
Enter Load Factor	80 %	` 0
	Generator Characteristics	
Enter Net Capability (kW)	4,000 kW	×
Enter Backup Hours	73 Hou	lours
Enter Maintenace Hours	73 Hou	lours

Note: Sum of Forced Outage Hours and Maintenance Outage Hours must be less than 730

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 55 of 118

\$ 412 \$ 26,484 \$ 17,784 \$ 42,430 \$ 87,111 0.07458

Customer Demand Energy Riders Total \$/kWh

		Large General S	ervice at Primar ther Period	y Voltage			
		Re	ervation Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total Reservation Charges Customer Demand Energy	\$ 412 \$ 7,643 \$.	usse Charges Customer Demand Energy	1 \$ 4,000 \$ 2,336,000 \$	412.37 \$ 2.79 \$ 11 - \$	412	\$ 412.37 \$ 1.93 \$ 5	\$ 412 \$ 7,643 \$
Total Cost	\$ 7,993	Riders Capacity Acquisition Rider	8,055	-0.7656% \$	(62)		
Total Maintenance Charges Demand	\$ 1.315	Ma Base Charges Demand	ntenance Charges nits Rate 16.000 \$	Charge 0.1113 \$ 1	Volt. Adj. Reduced Units 781 15.840	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge \$
Energy Riders Total Cost	\$ 4,446 \$ 8,003 \$ 13.763	E nergy Riders	292,000 \$	0.01538 \$ 4	491 289,080	0.01538	\$ 4,446
s,kwh	\$ 0.04713	Energy Cost Recovery Rider (\$KWh) Energy Efficiency Cost Rate Rider (\$KWh) Grand Guilt Prider (SGS anertor 1.GS & 1PS Damand)	292,000 \$ 292,000 \$ 4,000 \$	0.01783 \$ 5 0.00178 \$	206 289,080 520 289,080 - 360	0.01783 5 0.0178 5 0.00178	\$ 5,154 \$ 515 \$
		Federal Litigation Consulting Fee Rider (\$KWh)	292,000 \$	0.00566 \$ 1	15 289,080 653 289,080	0.00566	1,636
		Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	6,494 4,000 \$	-0.7656% \$ 0.18505 \$	(50) 740 3,960	0.1851	\$ 733
			ackup Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total backup Charges Demand Energy	\$ 3,528 \$ 4,446	Base Charges Demand Energy	16,000 \$ 292,000 \$	0.251 \$ 4 0.01538 \$ 4	15,840 491 289,080	0.22 0.22 0.22 0.01538	\$ 3,528 \$ 4,446
Kiders Total Cost	\$ 7,986 \$ 15,959	Riders Fnamv. Cost Racovary Ridar (SJKWh)	292,000 \$	0.01783 \$ 5	206 289 080	0.017.83	5.154 5
\$/k/Vh	\$ 0.05466	Energy Efficiency Cost Rate Rider (\$KWh) Grand Gulf Rider (SGS energy, LGS & LPS Demand)	292,000 \$ 4,000 \$	0.00178 \$	520 289,080 - 3,960	0.00178	\$ 515 \$
		Federal Litigation Consulting Fee Rider (\$kWh) Production Cost Allocation Rider (\$kWh)	292,000 \$ 292,000 \$	0.00005 \$ 1	15 289,080 653 289,080	0.00005 0.0000566 0.00566	\$ 14 \$ 1,636
		Capacity Acquisition Kider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	8,706 4,000 \$	-0./020% \$ 0.18505 \$	(b/) 740 3,960	0.1851	\$ 733
		Sup	olemental Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
rotal supplemental charges Demand Energy Riders	\$ 13,999 \$ 8,892 \$ 22,953	Base triarges Demand Energy	2,000 \$ 584,000 \$	7.93 \$ 15 0.01538 \$ 8	,860 1,980 ,982 578,160	5 \$ 7.07 5 \$ 0.01538	\$ 13,999 \$ 8,892
Total Cost	\$ 45,843	Riders Energy Cost Recovery Rider (\$\kVMh) Energy Cost Recovery Rider (\$\kVMh)	584,000 \$ 584,000 \$	0.01783 \$ 10	413 578,160 040 578,160	0.01783	\$ 10,309
		Grand Guif Rider (SGS energy, LGS & LPS Demand) Federal Litigation Consulting Fee Rider (SkVVh)	4,000 \$ 584,000 \$	1.96 \$ 7	840 3,960 29 578,160	5 1.96 S	\$ 7,762 \$ 29
		Production Cost Allocation Rider (\$/k//h) Capacity Acquisition Rider	584,000 \$ 23,623	0.00566 \$ 3	,305 578,160 (181)	0.00566	\$ 3,272
		Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000 \$	0.18505 \$	740 3,960	0.1851	\$ 733
		Municipal	anchise Adjustment Ride nits Rate	Charge			
		reservation Charges Maintenance Charges Backup Charges Cuantemortet	7,993 13,763 15,959 4 E 049	4.250% \$ 4.250% \$ 4.250% \$	340 585 678		
			240/04	* e/nn7:*	0+0		

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 56 of 118

Tota Supl Supl Base Base Mair Mair

Monthly Billin	g Units
al Demand	30,000
pplmental Demand	10,000
seload Demand	20,000
d Factor	75.00
plemental Load Factor	25.00
nthly Energy	16,425,000
oplemental Energy	1,825,000
seload Energy	13,000,000
skup Energy	800,000
ntenance Outage Energy	800,000
skup Duration	2
ntenance Duration	2

Note: Sum of Forced Outage Hours and Maintenance Outage Hours must be less than 730

Enter Net Capability (kW) Enter Backup Hours Enter Maintenace Hours

20,000 kW 40 Hours 40 Hours

Generator Characteristics

Load Characteristics Inputs Season <mark>mmer Perio</mark>

Select Season From Drop Down

Enter Peak Demand (KW) Enter Load Factor

30,000 kW 75 %

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 57 of 118

412 101,916 72,568 145,941 320,837 0.09367

Customer Demand Energy Riders Total \$/kWh

~ ~ ~

		Large Power Servic Sur	e at Transmiss 1 mer Period	ion Voltage				
		Reso Uni	vation Charges is Rate	Charge	Volt. Adj. Reduced Ur	its Volt. Adj. Reduced Ra	te Volt. Adj. Reduced	Charge
Total Reservation Charges Customer Demand Deergy	\$ 19,012 \$ 19,012 \$ -	Base Charges Base Charges Demand Energy	1 \$ 20,000 \$ 13,000,000 \$	412.37 \$ 2.79 \$ - \$	412 5,800 - 12,74	1 \$ 41 1600 \$ 0,000 \$	2.37 \$ 0.97 \$ - \$	412 19,012 -
rkoers Total Cost	\$ (149) \$ 19,276	Riders Capacity Acquisition Ride r	19,424	-0.7656% \$	(149)			
		Maint	enance Charges ts Rate	Charge	Volt. Adj. Reduced Ur	its Volt. Adj. Reduced Ra	te Volt. Adj. Reduced	Charge
Total Maintenance Charges Demand Enerory	\$ 2,654 \$ 16.950	Base Charges Demand Enerrov	40,000 \$ 800.000 \$	0.12750 \$	5,100 3 7.296 78	200 \$ 0.0	5770 \$ 2162 \$	2,654 16.950
Riders Total Cost	\$ 23,300 \$ 42,904	Riders						
SKWh	\$ 0.05363	Energy Cost Recovery Rider (\$/kWh) Energy Efficiency Cost Rate Rider (\$/kWh)	800,000 \$ 800,000 \$	0.01783 \$ 1 0.00178 \$	4,264 78 1.424 78	1,000 \$ 0.0 1,000 \$ 0.0	1783 \$ 0178 \$	13,979 1.396
		Grand Guif Rider (SGS energy, LGS & LPS Demand) Federal Lititiation Consulting Fee Rider (\$kWh)	20,000 \$ 800,000 \$	0.00005 \$	40 78	600 \$ 0.0	. 5	. 68
		Production Cost Allocation Rider (\$KWh) Canactiv Acruitistion Rider	800,000 \$	0.00566 \$	4,528 78	0.0 \$ 000,	3566 \$	4,437
		cepterity Acquisition Nater Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000 \$	0.1851 \$	3,701 1	,600 \$ 0.	1851 \$	3,627
		Uni	skup Charges is Rate	Charge	 Volt. Adj. Reduced Ur 	its Volt. Adj. Reduced Ra	te Volt. Adj. Reduced	Charge
Total Backup Charges	s a 208	Base Charges	40.000 \$	1 2 702 0	1 880	200 S	0.24 \$	9 29R
Energy	\$ 16,950	Energy	800,000 \$	0.02162 \$ 1	7,296 78	0.0 \$ 000	2162 \$	16,950
Total Cost	\$ 23,249 \$ 49,497	Riders						
S/k//h	\$ 0.06187	Energy Cost Recovery Rider (\$/k\Wh) Energy Efficiency Cost Rate Rider (\$/k\Wh)	800,000 \$ 800,000 \$	0.01783 \$ 10.00178 \$	4,264 78 1,424 78	1,000 \$ 0.0 1,000 \$ 0.0	1783 \$ 0178 \$	13,979 1,396
		Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000 \$	s		,600 \$ 500 \$	- \$,
		Federal Lingation Consulting Fee Kider (\$KWh) Production Cost Allocation Rider (\$KWh)	800,000 \$ 800,000 \$	0.00566 \$	40 78 78	0.0 \$ 000,	2566 \$	38 4,437
		Capacity Acquisition Kider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	29,875 20,000 \$	-0.7656% \$ 0.1851 \$	(229) 3,701 1	,600 \$ 0.	1851 \$	3,627
		Suppl	emental Charges ts Rate	Charge	Volt. Adj. Reduced Ur	its Volt. Adj. Reduced Ra	te Volt. Adj. Reduced	Charge
Total Supplemental Charges Demand Energy	\$ 70,952 \$ 38,667	Base Charges Demand Energy	10,000 \$ 1,825,000 \$	9.0600 \$ 9 0.02162 \$ 3	0,600 9,457 1,78	,800 \$ 7. 1,500 \$ 0.0	2400 \$ 2162 \$	70,952 38,667
Total Cost	\$ 196,080	Riders	e 000 100 1					000 10
S/k/Vh	\$ 0.10744	Energy Cost Recovery Rider (\$KWh) Energy Efficiency Cost Rate Rider (\$KWh) Cond Cut Rider (SKWh)	1,825,000 \$ 1,825,000 \$	0.001783 \$ 3	2,540 1,78 3,249 1,78	1,500 \$ 0.0 1,500 \$ 0.0	1783 \$ 0178 \$	31,889 3,184 20,446
		Federal Luin Kuer (303 errer gy, Lo3 & LrS Verhain) Federal Lingation Consulting Federal (\$KWh)	1,825,000 \$	0.00005 \$ 3	91 1,78	2,500 \$ 0.0	0005 \$	30,410 89
		Frouturent Cost Antoducti Note (2009) Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	113,246 20,000 \$	-0.7656% \$ -0.1851 \$	(867) 1.10 3,701 1	,600 \$ 0.	1851 \$	3,627
		Municinal Era	schise Adjustment Rider					
		Uni Receivation Charges	ts Rate 19.276	Charge 4 250% S	810 8			
		Maintenance Charges Backup Charges	49,497	4.250% \$	2,104			
		Supplemental Charges	196,080 Stand Total	4.250% \$	8, 333			

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 58 of 118

ays ays ays Tota Supl Supl Base Base Mair Mair

Monthly Billing	g Units	
al Demand	30,000	~
plmental Demand	10,000	~
seload Demand	20,000	~
d Factor	75.00	ŝ.
plemental Load Factor	25.00	ŝ.
nthly Energy	16,425,000	~
oplemental Energy	1,825,000	~
seload Energy	13,000,000	~
skup Energy	800,000	~
ntenance Outage Energy	800,000	~
skup Duration	21	_
ntenance Duration	21	

Note: Sum of Forced Outage Hours and Maintenance Outage Hours must be less than 730

Enter Net Capability (kW) Enter Backup Hours Enter Maintenace Hours

20,000 kW 40 Hours 40 Hours

Generator Characteristics

Load Characteristics Inputs Season <mark>ither Period</mark>

Select Season From Drop Down

Enter Peak Demand (KW) Enter Load Factor

0,000 kW 75 %

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 59 of 118

			Other Period				
			iervation Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total Reservation Charges Customer Demand Energy Riders	\$ 412 \$ 19,012 \$ -	Customer Customer Demand Energy	20,000 \$ 13,000,000 \$	412.37 \$ 2.79 \$ 55 - \$	412 800 19,60 - 12,740,00	1 \$ 412.37 00 \$ 0.97 00 \$ -	\$ 412 \$ 19,012 \$
Total Cost	\$ 19,276	Riders Capacity Acquisition Rider	19,424	-0.7656% \$	(149)		
		Mai	ntenance Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total Maintenance Charges Demand Energy	\$ 2,019 \$ 12,058	Base Charges Demand Energy	40,000 \$ 800,000 \$	0.11130 \$ 4 0.01538 \$ 12	452 39,2(,304 784,0)	00 \$ 0.05150 00 \$ 0.01538	\$ 2,019 \$ 12,058
Total Cost	\$ 37,419	Fiders Energy Cost Recovery Rider (\$KVM)	800,000 \$	0.01783 \$ 14	784,0	00 \$ 0.01783	\$ 13,979
11.0X%	10000	Errergy Enrudency Cost vale Kuert (www.) Grand Gulf Rider (SGS energy, LGS & LPS Demand) Federal Lightation Consulting Fee Rider (\$/Wh)	20,000 \$ 20,000 \$ 800,000 \$	0.0005 \$	- 19,60 - 19,60 - 784,00	00 \$ 0.0005	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$
		capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000 \$	0.1851 \$ 3	701 19,60	00 \$ 0.1851	s 3,627
			ackup Charges	i			
Total Backup Charges Demand Energy	\$ 7,495 \$ 12,058	Demand Demand E nergy	1115 Kate 40,000 \$ 800,000 \$	Cnarge 0.251 \$ 10 0.01538 \$ 12	Voit. Adj. Keduced Units 040 39,20 304 784,00	Volt. Adj. Keduced Kate 00 \$ 0.19 00 \$ 0.01538	/ oit. Agj. Reduced Charge \$7,495 \$12,058
Riders Total Cost	\$ 23,300 \$ 42,853	Riders Enormy Crot Docentrar (SW1Mb)	9 000 000	0.01782 6 14	0 F07	\$ 001780 001782	12 070
s/k/vh	\$ 0.05357	Energy Cost Recovery Area (Swrwin) Energy Efficiency Cost Rate Rider (S/Wh) Grand Guift Rider (SGS energy 1 GS & 1 PS Demand)	800,000 \$	0.00178 \$ 1	424 784,01	00 \$ 0.00178	s 1,396
		Federal Lititation Consulting 97, ECG 41, Consultance Production Cost Allocation Rider (S/KWh)	800,000 \$	0.00005 \$	40 784,00 528 784,00	00 \$ 0.000566	s 39 S 4,437
		Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	23,180 20,000 \$	-0.7656% \$ 0.1851 \$ 3	177) 701 19,60	00 \$ 0.1851	\$ 3,627
		Sup	olemental Charges nits Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	/olt. Adj. Reduced Charge
Total Supplemental Charges Demand	\$ 56,840	Base Charges Demand	10,000 \$	7.6200 \$ 76	200 9,80	00 \$ 5.8000	\$ 56,840
Energy Riders	\$ 27,507 \$ 86,654	Energy	1,825,000 \$	0.01538 \$ 28	,069 1,788,50	00 \$ 0.01538	\$ 27,507
lotal Cost	100,171 &	Energy Cost Recovery Rider (\$KWh)	1,825,000 \$	0.01783 \$ 32	540 1,788,50	00 \$ 0.01783	31,889
⊗KWII	0/260'0 📚	Energy Emidency Cost Rate Rider (wKWN) Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000 \$	1.96 \$ 39	200 19,60	00 \$ 0.001/8 00 \$ 1.96	\$ 38,416
		Federal Litigation Consulting Fee Rider (\$/kWh) Production Cost Allocation Rider (\$/kWh)	1,825,000 \$ 1,825,000 \$	0.00566 \$ 10	91 1,788,56 ,330 1,788,56	00 \$ 0.00056 00 \$ 0.00566	s 89 s 10,123
		Capacity Acquisition Rider Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	87,974 20,000 \$	-0.7656% \$ 0.1851 \$ 3	(674) 701 19,60	00 \$ 0.1851	\$ 3,627
		Municipal F	anchise Adjustment Rider				
		U Reservation Charges	nits Rate 19,276	Charge 4.250% \$	819		
		Maintenance Charges Backup Charges	37,419 42,853	4.250% \$ 1 4.250% \$ 1	590 821		
		ouppennennal Criatiges	100'171	1 © %.0C7'F	007		

Large Power Service at Transmission Voltage Other Period

Customer \$ 412 Demand \$ 55,365 Energy \$ 51,623 Energy \$ 51,623 Total \$ 22,046 Yoth 0.08238

Attachment Arkansas - 3 Page 1 of 1

Entergy Arkansas Inc. - Standby Service Rider (SSR)

Modified reservation charge to reflect performance of best unit and transmission and distribution diversity.

	Voltage	Current	Revised			
Line	Level	<u>\$/kW</u>	<u>\$/kW</u>			
1	Primary	\$1.93	\$1.14			
2	Transmission	\$0.97	\$0.37			
				Monthly	Monthly	Monthly
		Self Gen		Current	Revised	Cost
	Scenerios	kW	Voltage	Cost	Cost	Difference
3	Small	700	Pri	\$1,351	\$796	\$555
4	Medium	4,000	Pri	\$7,720	\$4,550	\$3,170
5	Large	20,000	Trans	\$19,400	\$7,389	\$12,011

Notes:

1. All other charges remain the same.

2. Small impact of Capacity Acquisition Rider.

Modifications to the Standby Service Rider for on and off-peak charges can produce savings or costs.

6 7	Voltage <u>Level</u> Primary Transmission	Current Summer Backup Charge <u>\$/kW/Day</u> \$0.266 \$0.232	Current Other Backup Charge <u>\$/kW/Day</u> \$0.220 \$0.187	Estimated On-Peak Summer Backup Charge <u>\$/kW/Day</u> \$0.401 \$0.352	Estimated On-Peak Other Backup Charge <u>\$/kW/Day</u> \$0.333 \$0.285
8 9	Voltage <u>Level</u> Primary Transmission	Current Summer Maintenance Charge <u>\$/kW/Day</u> \$0.098 \$0.066	Current Other Maintenance Charge <u>\$/kW/Day</u> \$0.082 \$0.050	Estimated On-Peak Summer Maintenance Charge <u>\$/kW/Day</u> \$0.148 \$0.100	Estimated On-Peak Other Maintenance Charge <u>\$/kW/Day</u> \$0.124 \$0.077

Savings Analysis For Summer Period

	<u>Scenerios</u>	Self Gen <u>kW</u>	Voltage	Backup <u>Days</u>	Summer Monthly Backup <u>Savings</u>	Summer Monthly Maintenance <u>Savings</u>
10	Small	700	Pri	7	\$1,303	\$481
11	Medium	4,000	Pri	4	\$4,256	\$1,571
12	Large	20,000	Trans	2	\$9,298	\$2,654

Cost Analysis For Summer Period

	Scenerios	Self Gen kW	Voltage	Backup Davs	Summer Monthly Backup Costs	Summer Monthly Maintenance Costs
	ocenteritos	KU	Voltage	Days	00313	00313
13	Small	700	Pri	7	\$660	\$244
14	Medium	4,000	Pri	4	\$2,155	\$796
15	Large	20,000	Trans	2	\$4,776	\$1,363

Notes:

1. Savings and costs are calculated relative to the present rates.

2. On-peak rates are higher because total cost recovery is over a shorter period.

Savings occur when backup is needed during off peak periods such as weekends.
 Costs occur when backup is needed during on peak periods.

Attachment Colorado-1 Page 1 of 3

Public Service Company of Colorado Standby Rate Mode

Brubaker and Associates, Inc. (BAI) has created a model that estimates the monthly charges incurred by a Public Service Company of Colorado (PSCo) customer utilizing on-site generation under Standby Service Tariffs for both the Primary and Transmission (Schedules PST and TST) voltage levels. Supplemental power in excess of on-site generation is served under applicable standard tariffs. The two rate schedules analyzed in the model are: (1) Primary General Service (PG); and (2) Transmission General Service (TG). In addition, there are several riders that must be applied to each scenario.

The model requires the user to input five fields, either manually or from a drop down list:

- Season (choice of either Summer or Winter);
- Customer's peak demand;
- Customer's load factor;
- Net capability of the on-site generator; and
- Generator outage hours.

Based on these user-provided inputs, the model determines the amount of energy and power to be charged in three separate categories: Standby, Usage, and Supplemental.

The Standby charge is the charge associated with the capacity that PSCo must have available in case of either a forced outage (unscheduled) or a maintenance outage (scheduled) of the on-site generator. In the model, charges incurred in this category consist of the monthly Service and Facilities Fee, the monthly Interconnection Charge and the monthly Reservation Fee, based on the demand of the on-site generator and other applicable riders. Because the Interconnection Charge is customer specific for purposes of this model the Interconnection Charge was fixed at \$1,000 per month. Interconnection Charge applies only to Schedule TST customers.

Usage charges are associated with both capacity and energy that PSCo has to provide during planned and unplanned outages. The capacity is only billed after the Company has exceeded its Grace Energy. The annual Grace Energy for Standby capacity is 1,051 hours beginning October 1. The Usage demand charge will not be incurred until the outage has surpassed the Grace Energy hours. For this model the Grace Energy hours was developed on a monthly basis by dividing the Standby hours of 1,051 by 12 to equal approximately 88 hours per month. The energy charge is applicable to all energy that is billed under the Standby Service Tariff.

Customers with 10 kW to 10,000 kW of connected Standby capacity can request maintenance outages that must occur within the calendar months April, May, October, and November. Customers must provide PSCo with written notice of scheduled maintenance prior to the beginning of the maintenance period. Maintenance must occur at a time that is mutually agreed to by PSCo and the customer. The length of the maintenance outage is a function of the required notice given. Finally, qualified scheduled maintenance outages will not count against the grace period.

Supplemental charges cover the costs of electricity needed to fulfill the remainder of the customer load, i.e., the load less the on-site generation. Rates for supplemental usage are

Attachment Colorado-1 Page 2 of 3

found in Rate Schedules PG and TG with costs for Service and Facility Demand, Energy charges, and all applicable riders.

The model has a tab for each of the two customer classes, Primary and Transmission. On each of these tabs, the charges for the three categories are shown both in detail and summarized. Each category has the charges broken into four components: service and facility, demand, energy, and riders. These costs are then totaled, allowing for a per unit cost (\$/kWh) to be calculated for each category. The bottom left of each of the class tabs has the grand total of all charges.

Instructions for Using the Model

- 1. On the inputs tab, fill in all of the orange boxes. The season input is a drop down menu, and the rest must be manually entered.
- 2. Make sure the file calculates. Press F9 if necessary.
- 3. The model will now have each of the classes calculated for the inputs provided.
- 4. To evaluate various scenarios, alternative charges or rates will have to be inserted in the applicable rate "tab" which is discussed below.

Definition of Inputs

- Season The Summer Season is defined as June 1 through September 30. The Winter Season is defined as October 1 through May 31.
- **Peak Demand** The maximum demand in kilowatts that is required to fulfill the customer's entire load.
- Load Factor The ratio of average demand to peak demand over a period of time. For this model, that period of time is 730 hours. Can be calculated as the average monthly energy for the season divided by the peak demand times 730 hours.
- Generator Net Capability The net capacity of the on-site generator in kilowatts. Generally, the nameplate capacity of the unit less any environmental adjustments.
- Generator Outage Hours The number of hours in the month in which the generator will be offline due to both planned and unplanned outages. Must be less than 730 hours.

<u>Tabs</u>

The model has the following three other tabs:

• Primary: Contains charges for PST, PG, and the applicable riders. Displays the calculated costs for Reservation, Usage, and Supplemental capacity and energy.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 63 of 118

Attachment Colorado-1 Page 3 of 3

• Transmission: Contains charges for TST, TG, and the applicable riders. Displays the calculated costs for Reservation, Usage, and Supplemental capacity and energy.

The user views the costs on the appropriate tab.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 64 of 118

Monthy Billing Units 1,500 kW 1,500 kW mdby Capacity 700 kW 2000 % Load Factor 755,500 kW Evergy 255,500 kW at Efergy 255,500 kW Demand andby Capacity oupplemental Energy On-Site Generated Energy Usage Energy nental Load Factor Total Load Supplemental D Contracted Star Load Factor otal Energy

700 kW 40 Hours 1,500 kW 70 % Generator Characteristics Load Characteristics Inputs Season Summer Season Select Season From Drop Down Enter Net Capability (kW) Enter Generator Outage Hours Enter Peak Demand (kW) Enter Load Factor

Motes - Outage Hours must be less than 730 hours. - Outage greater than 88 hours will exceed Granz Energy Hours. 3. Summer Season is June 1 - Septemeber 30. Winter Season is October 1 - May 31.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 65 of 118

			Primary Summer Season					
Total Reservation Charges Customer Demand Total Cost		305 1,078 404 1,787	Reservation Gharges Base Charges Base Charges Base Charges Barlos and Facilies Charge Interconnection Charge (SMM) Generation and Transmission Deminand Charge (SMM)	Units	Rate 1 \$ 700 \$ 700 \$	305.00 \$ 3.98 1.54 \$	arge 305 1,078	
			Riders Generates Schedule Adjustment (SRSA) Generat-Sick Management Cost Adjustment - Standby Service - Reservation (\$NV-Mo) Purthased Capacity Sock Adjustment - Standby Service - Reservation (\$NV-Mo) Transmission Cost Adjustment - Standby Service - Reservation (\$NW-Mo) Electric Commodity Adjustment (\$NVM)		1,383 700 \$ 700 \$ -	14.05% \$ 0.04 \$ 0.26 \$ - \$ 0.02955 \$	194 28 182	
Total Usage Charges Demand Energy Riders	8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8 8	- 129 2,435	Urange Changes Base Changes Demand Change (KNW) Energy Change (KNW)	Units	Rate - \$ 8,000 \$	Ch 11.31 \$ 0.00461 \$	arge - 129	
Total Cost \$KWM	w w	2,564 0.09156	Notes Benear State Schedule Adjustment (GRSA) Demand Scie Management Cost Adjustment - Standby Service - Usage (\$WV-Mo) Purchased Capacity Cost Adjustment - Standby Service - Usage (\$WV-Mo) Transmission Cost Adjustment (\$RVVM) Electic Commonly Adjustment (\$RVVM)	N	129 700 \$ 700 \$ 8,000 \$	14.05% \$ 14.05% \$ 14.05% \$ 1.89 \$ 0.01 \$ 0.0	18 259 1,323 7 827	
			Supplemental Charges	Units	Rate	ซ	arge	
Total Supplemental Charges Customer Demand Energy Ridens Total Cost	~ ~ ~ ~ ~ ~	305 11,216 1,178 11,390 23,784	ease charges Barvice and Facilities Charge Distribution formand Charge (\$kW) Generation and Transmission Demand Charge (\$kW) Energy Charge (\$kWn)	25	1 \$ 800 \$ 800 \$ 5,500 \$	305.00 \$ 3.98 \$ 10.04 \$ 0.00461 \$	305 3,184 8,032 1,178	
Livuna Rikuna	\$	608800	Riders General Rate Schedule Adjustment (GRSA) Demand-Steh Mangement Cost Adjustment - Central Service (\$KW-Mo) Purchased Caparty Ost Adjustment - Central Service (\$KW-Mo) Transmission Cost Adjustment - Central Service (\$KW-Mo) Electric Commodity Adjustment (\$KWh)	56 1	2,699 800 \$ 800 \$ 800 \$ 500 \$	14.05% \$ 0.41 \$ 2.15 \$ 0.01 \$ 0.02955 \$	1,784 328 1,720 8 8 7,550	
			Ronowable Enorgy Standard Adjustment Reservation Charges Usage Charges Supplemental Charges	Units	Rate 1,787 2,564 3,784	€ CH 5.00% CH 2.00% CH	arge 36 51 476	
Customer Demaind Relears Total	~~~	610 12,294 1,711 1,711 16,175 30,790 0.10861						

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 66 of 118

			Primary Winter Season				
Total Reservation Charges Customer Demand Miders Total Cost	8 6 6 8	305 511 325 1,141	Reservation Charges Base Charges Service and Follates Charge Service and Follates (Sharge Interconnection Charge (SMV) Obtimution Demand Charge (SMV) Obtimution Demand Charge (SMV)	Units	Rate 1 \$ 10 \$ 00 \$	Chan 305.00 \$ 3.98 0.73 \$	Je 305 - 511
			Ridens General Rate Schedule Adjustment (GRSA) General Schedule Adjustment (GRSA) Demand-Side Management (GRSA) Performed Casardy Social Adjustment - Standry Sterrice - Reservation (SKW-Mo) Transmission Cost Adjustment - Standry Sterrice - Reservation (SKW-Mo) Electric Commodity Adjustment (SKWI)	0 K K K	316 700 \$ 700 \$ 700 \$ 700 \$	14.05% \$ 0.04 \$ 0.26 \$ 0.26 \$ 0.02955 \$	115
Total Usage Charges Demmid Energy Total Cost \$kWh	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	129 2,564 0.09156	Ustran Gunrops Base Charges Demand Charge (SKW) Energy Charge (SKW) Energy Charge (SKW) Ridens Ridens Ridens Parana Stee Adjustment (CRSA) Demand Stee Management (CRSA) Demand Stee Management (CRSA) Transmission Cost Adjustment - Stanchy Stervice - Usage (SKW-Mo) Paranasco Cast Adjustment - Stanchy Stervice - Usage (SKW-Mo)	Units 28,0	- Rate 00 \$ \$ 129 \$ 00 \$ 00 \$	Chart 5.34 \$ 0.00461 \$ 14.05% \$ 0.37 \$ 1.89 \$ 0.01 89	125 125 1,323 1,323
Total Supplemental Charges Customer Customer Energy Frees Totals	666	305 8,808 1,178 11,052	Lectric Commonly Aquisment (s.v.w.) Supplemental Ohitiges Base Charges Service and Facilities Charge Service and Facilities Charge Distribution Demand Charge (\$WW) Energy charge (\$WW)	Units 25,5	00 \$ Rate	0.00461 \$	3,184 5,624 1,178
I clail Cost SikWh	м м	21,038	Riders General frame Schedule Adjustment (GRSA) General Fase Schedule Adjustment (GRSA) Demand-Stele Management (Cost Adjustment - General Service (\$KW-Mo) Purchanges (Cast Adjustment - General Service (\$KW-Mo) Electric Commonly Adjustment (\$KWM)	10,2 8 8 8 255,5	681 000 0 0 0 000 0 0 0 000 0 0 0 000 0	14.05% \$ 0.41 \$ 2.15 \$ 0.01 \$ 0.02955 \$	1,446 328 1,720 1,720 8 7,550
			Renewable Energy Standard Adjustment Reservation Charges Usage Charges Supplemental Charges	Units 1,1 2,5 2,1,0 2,1,0	Rate 64 38	Char 2.00% \$ 2.00% \$ 2.00% \$	16 51 421
Customer Demand Erengy Riders Total	~ ~ ~ ~ ~ ~	610 9,319 1,632 15,122 26,683 26,683 0.09412					

NNE -

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10025

12000

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 67 of 118

Monthy Billing Units 6,000 kW Bernand 2,000 kW andby Capacity 4,000 kW Load Factor 3,04000 kW Energy 564,000 kWh ated Energy 2,22000 kWh Total Load Supplemental Demand Contracted Standby Capacity Load Factor Supplemental Load Factor Total Energy On-Supplemental Energy Usage Energy

4,000 kW 50 Hours 6,000 kW 80 % Generator Characteristics Load Characteristics Inputs Season Winter Season Select Season From Drop Down Enter Peak Demand (kW) Enter Load Factor

Enter Net Capability (kW) Enter Generator Outage Hours

Notes 1. Outage Hours must be less than 730 hours. 2. Outage greater than 68 hours will exceed Grace Energy Hours. 3. Summer Season is Lure 1 - September 30, Winner Season is October 1 - May 31.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 68 of 118

			Primary Summer Season					
			Reservation Charges U	lits	Rate		harge	
Total Reservation Charges Customer Demand Riders Total Cost	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	305 6,160 8,573	Base Charges Base Charges Interconnection Charge Distribution Denard Charge (SWV) Generation and Thransmission Damard Charge (SWV)	4,0 0,4	900 0	305.00 - 3.98 1.54		305 - ,160
			Riders General Rate Schedule Adjustment (GRSA) Demand-Side Management Cost Adjustment - Standby Service - Reservation (\$KW-Mo) Purchased Capachy Cost Adjustment - Standby Service - Reservation (\$KW-Mo) Transmission Cost Adjustment - Standby Service - Reservation (\$KW-Mo) Electric Commodity Adjustment (\$KW)	9.4.4.4 4.000 -	90008 8888	14.05% 5 0.04 9 0.26 9 0.255 9	-	908 160 -
Total Usage Charges Demand	69 -		Usage Charges Base Charges Demand Charge (\$KW)	its.	s Rate	11.31 C	harge	
Energy Riders Total Cost	w w w	922 15,120 16,042	Energy Charge (\$KWh) Riders	200,0	\$	0.00461 \$		922
skwh	\$	0.08021	General Rate Scheude Augustmert (Starter) Demand-Steid Amangement Cast Adjustment - Standby Service - Usage (\$KW-Mo) Purchasade Cagaroly Cast Adjustment - Standby Service - Usage (\$KW-Mo) Transmission Cast Adjustment - Standby Service - Usage (\$KW-Mo) Effective Commodity Adjustment (\$KW)	9 0,4,0 20,0	*****	14.05% 3 0.37 \$ 1.89 \$ 0.01 \$ 0.02955	~ ∩ ~ 0	130 560 40 ,910
Total Sunniamantal Charrase			Supplemental Charges U	lits	Rate	J	harge	
Customer Customer Demand Energy Frees Trail Cast	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	305 28,040 2,692 26,758 57 491	Service and facilities Charge Distruction Demand Charge (SKW) Generation and Transmission Demand Charge (SKW) Energy Charge (SKW))	2,0 284,0	0000 - 0000 -	305.00 \$ 3.98 \$ 10.04 \$ 0.00461 \$	202	305 960 080 692
SKWh	e e e e e e e e e e e e e e e e e e e	0.09844	Riders General Rate Schedule Adjustment (CRSA) Demand-Side Management Cost Adjustment - General Service (\$KW-MO) Purchased Capacity Cost Adjustment - General Service (\$KW-MO) Transmission Cost Adjustment - General Service (\$KW-MO) Electric Commodity Adjustment (\$KWM)	31,0 2,0 584,0	000 \$ 000 \$ 000 \$	14.05% \$ 0.41 9 2.15 \$ 0.01 \$ 0.02955 \$	4 4 ^C	361 820 20 258 20
			Renewahle Energy Standard Adjustment					
			U Reservation Charges Usage Charges Supplemental Charges Grown Trank	1115 8,5 57,41	Kate 73 42 91	2.00% \$	harge	171 321 150
Customer	v	610						
Demand Energy Riders	~ ~ ~ ~	34,200 5,723 52,094						
Total \$/kWh	67	92,626 0.11815						

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 69 of 118

			Primary Winter Season					
			Reservation Charges	its	Rate	C	harge	
Total Reservation Charges Oustonner Demand Riders Total Cost	\$ \$ \$ \$ \$	305 2,920 4,878	Base Changes Booide and Facilities Charge Interconnection Charge Bittabulo Demand Charge (SWV) Generation and Transmission Domand Charge (SKW)	4,90 00,4	6 6 6 6 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7 7	305.00 3 - 5 0.73 \$		305 - ,920
			Riders General Rate Schedule Adjustment (GRSA) Demand-Side Managament Cost Adjustment - Standby Service - Reservation (\$KWV-Mo) Demand-Side Managament - Sandby Service - Reservation (\$KWV-Mo) Tarasmission Cost Adjustment - Standby Service - Reservation (\$KWV-Mo) Electric Commodity Adjustment (\$KWN)	3,22 4,00 4,00 -	۵۵ ۵۵ ۵۵ ۵۵	14.05% \$ 0.04 \$ 0.26 \$ 0.02955 \$	-	453 160
			Usage Charges Un	its	Rate	U	harge	
Total Usage Charges Demand Energy Riders	~ ~ ~ ~	- 922 15,120	Base Charges Benand Charge (\$KWN) Energy Charge (\$KWN)	200,00	\$ \$ 0	5.34 \$ 0.00461 \$		- 922
ା ପାଣା Cost କ୍ଟିନେଏନା	e e	0.08021	Nuers General Rate Schedule Adjustment (GRSA) Demand-Side Management Cost Adjustment - Standby Service - Usage (\$MV-Mo) Turchased Capacity Cost Adjustment - Standby Service - Usage (\$MV-Mo) Transmistern Cost Adjustment - Standby Service - Usage (\$MV-Mo) Electric Commodity Adjustment (\$MVM)	92 4,00 4,00 200,00 200,00	۵۵ ۵۵ ۵۵ ۵۵ ۵۵	14.05% \$ 0.37 \$ 1.89 \$ 0.01 \$ 0.02955		130 480 560 910
Total Sumolomortal Character			Supplemental Charges Dago Charges	its	Rate	U	harge	
Cud supprenental oriarges Customer Demand Energy Riders Total Cost	~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	305 22,020 2,692 25,913 50,625	Sere vice and Facatiles Charge Distruction Demand Charge (RWM) Generation and Transmission Demand Charge (SWM) Energy Charge (SWM)	2,00 2,00 584,00	0 0 0 ۳ ۳ ۳ ۴	305.00 \$ 3.98 \$ 7.03 \$ 0.00461 \$	r 4 0	305 960 692
SKWh	\$	0.08669	Riders Demarks Schedule Adjustment (CRSA) Demarks Stie Management Cost Adjustment - General Service (\$KW-Mo) Purchased Casady (Cost Adjustment - General Service (\$KW-Mo) Transmission Cost Adjustment - General Service (\$KW-Mo) Electric Commodity Adjustment (\$KWm)	25,01 2,00 2,00 2,00 584,00	9 8 8 8 9 0 8 8 9 0 8 8	14.05% \$ 0.41 \$ 2.15 \$ 0.01 \$ 0.02955 \$	ο 4 [515 820 20 258 26
			Renewable Enviroy Standard Adjustmant Reservation Charges Usago Charges Supplemental Charges	its 4,87 16,04 50,62	Rate 8 5	C 2.00% \$ 2.00% \$ 2.00% \$	harge 1	98 321 012
			Grand Total					
Customer Demand Elergy Total SKWh	~~~~ ~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~~	610 24,940 5,267 78,159 78,159 0.09969						

ter	A	Þ
q	\$	24,9
	\$	5,2
	s	47,34
	\$	78,1
		0.0991

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 70 of 118

Monthy Billing Units 3000 kW Bernand 10000 kW andby Capacity 20000 kW 2500 kg Load Factor 154,25000 kW Energy 1825,000 kW Berlegy 1825,000 kW Berlegy 1825,000 kW Total Load wonthy builting supplemental Demand Contracted Standby Capacity Load Factor Supplemental Load Factor Total Energy On-Sile Generated Energy Usage Energy

30,000 kW 75 % Generator Characteristics Load Characteristics Inputs Season Select Season From Drop Down Writter Season Enter Net Capability (kW) Enter Generator Outage Hours Enter Peak Demand (kW) Enter Load Factor

20,000 kW 40 Hours

Notes - Outget Hours must be less than 730 hours. 2. Outges grader than 86 hours will socked Grade Energy Hours. 3. Summer Season is June 1 - September 30. Winter Season is October 1 - May 31.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 71 of 118

		Summer Season Reservation Charges			
Total Reservation Charges Customer Denand Rides Total Cost	 5 1,45 5 9,240 6 6 6 6 7 9 6 4 7 7	Base Charges Until 0 Barve Charges 0 1 Barve Charges 0 0 Interconnection Charge 0 1 Distribution Demand Charge (\$KW) 0 2 Generation and Transmission bemand (Charge (\$KW) 0 2 Generation (\$KNA) 0 2 Generation (\$KWA) 0 2 Generation (\$KNA) 0 2 Demand State Adjustment (\$KNA) 0 2 Transmission Cost Adjustment (\$KNA) 0 2	Rate 20,000 \$ 20,000 \$ 20,0000 \$ 20,0000 \$ 20,0000 \$ 20,0000 \$ 20,0000 \$ 20,0000 \$ 2	Cha 450.00 \$ 1,000.00 \$ 1.42 \$ 14.05% \$ 0.24 \$ 0.24 \$ 0.2330 \$	rge 450 1,000 28,400 4,194 800 4,800 -
Total Usage Charges Demand Energy Total Cost Skivin	\$ 3,000 \$ 3,000 \$ 70,155 \$ 0.08766	Ustige Charges Base Charges Damad Charge (\$KW) Base Charges Damad Charge (\$KW) Every Charge (\$KW) Base Charges Charges (\$KW) Base Charges (\$KW) Base Charges (\$KW) Charge (\$KW) Base Charges (\$KW) Charges (\$KW) Charges (\$KW) Base Charges (\$KW) Charges (\$KW) Charges (\$KW) Charges (\$KW) Base Charges (\$KW) Charges (\$KW) Base Charges (\$KW) Charges (\$KW) Base Charges (\$KW) Charges (Rate 800,000 \$ 3,608 \$ 20,000 \$ 20,000 \$ 800,000 \$	Cha 10.43 \$ 0.00451 \$ 14.05% \$ 17.034 \$ 1.738 \$ 0.01 \$	rge 3,608 6,800 35,600 23,438 23,438
Total Supplemental Charges Costomer Costomer Demaid Energy Total Cost Total Cost	 1,000 96,800 8,23 8,23 92,466 197,491 91,010822 	Supplemental Charges Unit Base Charges Base Charges Charges Charge (SkW) Base Charges Charges Penetral Rate Stead Management. General Service (SkW-Mo) Transission Cast Adjustment. General Service (SkW-Mo) Transission Cast Adjustment. General Service (SkW-Mo) Transission Cast Adjustment (SkW)	RAte 10,000 5 10,000 5 1,825,000 5 10,000 5 10,000 5 10,000 5 1,825,000 5 1,825,000 5	Cha 1,000,00 \$ 9.68 \$ 0,00451 \$ 14,05% \$ 2,02 \$ 2,02 \$ 0,01 \$	rg e 1,000 96,800 8,231 14,897 3,800 20,200 53,468
		Renewable Etiegy Standard Adjustment Reservation Charges Unsige Oberges Supplemental Charges	s Rate 39,644 70,153 197,496	Cha 2.00% \$ 2.00% \$ 2.00% \$	rge 793 1,403 3,950
Customer Demand Tenergy Riders Total	2,450 2,450 2,1633 2,1633 5,204,800 5,354,083 0,13488 0,13488				

Transmission

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 72 of 118

		Winter Season Proceeding Character			
		enfilmer unmanazari	Units Rate	Cha	rge
Total Reservation Charges Ouslomer Demand Riders Total Cost	\$ 1,450 \$ 13,200 \$ 7,658 \$ 22,308	Base charges Service and Fradue Charge Interconnection Charge (SKVV) Detribution Demrand Charge (SKVV) Generation and Transmission Demrand Charge (SKVV)	20,000 \$ 20,000 \$ 20,000 \$	450.00 \$ 1,000.00 \$ 0.66 \$	450 1,000 13,200
		Riders General Rate Schedule Adjustment (GRSA) Demeral Rate Schedule Adjustment (SRSA) Demerad Semagement Cost Adjustment - Standby Service - Reservation (\$KW-Mo) Purchased Capacity Oct Adjustment - Standby Service - Reservation (\$KW-Mo) Transmission Cost Adjustment - Standby Service - Reservation (\$KW-Mo) Electric Commonity Adjustment - Standby Service - Reservation (\$KW-Mo)	14,650 20,000 \$ 20,000 \$ 20,000 \$ 5	14.05% \$ 0.04 \$ 0.24 \$ 0.24 \$ 0.02930 \$	2,058 800 4,800
Total Usage Charges Demand Energy	99°5 99809°5 99809°5	Base Charges Demand Charge (\$KVV) Energy Charge (\$KVM)	Units Rate 800,000 \$	Cha 4.87 \$ 0.00451 \$	rge 3,608
Huders Total Cost \$/k/v/h	\$ 70,153 \$ 70,153 \$ 0.08769	Riders General Be Schedule Adjustiment (GRSA) Demand-Sida Managoment Cost Adjustment - Standby Service - Usage (\$KW-Mo) Purchasado Capady Cast Adjustment - Standby Service - Usage (\$KW-Mo) Transmission Cost Adjustment - Standby Service - Usage (\$KW-Mo) Electric Commodity Adjustment (\$KWN)	3,608 20,000 \$ 20,000 \$ 20,000 \$ 800,000 \$	14.05% \$ 0.34 \$ 1.78 \$ 0.01 \$ 0.01 \$	507 6,800 35,600 200 23,438
		Supplemental Charges	llrite Data	εų.	
Total Supplemental Charges Customer Demand Energy Riders	\$ 1,000 \$ 66,800 \$ 8,231 \$ 88,250 \$ 163,281	Base Charges Service and Faolities Charge Distribution Demand Charge (\$KW) Generation and Transmission Demand Charge (\$KW) Energy Charge (\$KW)	10,000 \$ 10,000 \$ 1,825,000 \$	1,000.00 \$ 1,000.00 \$ 6.68 \$ 0.00451 \$	1,000 - 66,800 8,231
S/KWh	\$ 0.08947	Riders General Rate Schedule Adjustment (GRSA) Demands Stide Management Cost Adjustment - General Service (\$KW-140) Teurdased capachy Cost Adjustment - General Service (\$KW-140) Transmission Cost Adjustment - General Service (\$KW-140) Electric Commodity Adjustment (\$KW0)	76,031 10,000 \$ 10,000 \$ 1,825,000 \$	14.05% \$ 0.38 \$ 2.02 \$ 0.01 \$ 0.02330 \$	10,682 3,800 20,200 53,468
		Renewelkle Energy Standard Adjustment Reservation Charges Usage Charges Supplemental Charges	Units Rate 22,308 70,153 163,281	Cha 2.00% \$ 2.00% \$ 2.00% \$	rge 446 1,403 3,266
Customer Demand Terergy Riders Total	\$ 2,450 \$ 80,000 \$ 19,497 \$ 182,219 \$ 284,166 0.10825				

Transmission
Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 73 of 118

> Attachment Colorado-1 Page 1 of 3

PSCo Standby Costs Compared with Costs Associated with Suggested Revision

- The attached four graphs show the comparison of demand charges only under the current PSCo rates and suggested rate changes.
- A graph is provided for each voltage level and each season.
- For this comparison, the peak demand and the capability of on-site generators are set equal to one another. This ensures that there are no demand charges for supplemental power. The primary customer was assumed to be 700 kW, and the transmission customer was assumed to be 20,000 kW.
- The x-axis represents the duration in days of the generator outage from 1 to 30 days. The yaxis is the sum of demand charges from the reservation charge and usage charge categories.
- The standby service tariffs specify the annual Grace Energy Hours for a 100% load factor from the generator to be 1,051 hours. For this monthly analysis, 88 hours (1051/12) were utilized.
- Page 3 of 3 shows the estimated rates that produce the suggested cost changes.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 74 of 118



PSCo Standby Costs Compared with Costs Associated with Suggested Revision

Public Service Company of Colorado

Prima	ary (PST) & Transmissio	on (TST) Standb	y Service Rates				
Voltage <u>Level</u> Primary Trans	Current Summer Reservation Charge <u>\$/kW/Day</u> \$5.520 \$1.420	Current Winter Reservation Charge <u>\$/kW/Day</u> \$4.710 \$0.660	Revised Summer Reservation Charge <u>\$/kW/Day</u> \$3.686 \$0.484	Revised Winter Reservation Charge <u>\$/kW/Day</u> \$3.536 \$0.334			
Primary Rate PG & Transmission Rate TG							
G&T Voltage <u>Level</u> Primary Trans	Summer Demand Charge <u>\$/kW/Mo</u> \$10.04 \$9.68	Winter Demand Charge <u>\$/kW/Mo</u> \$7.03 \$6.68	Summer Demand Charge <u>\$/kW/Day</u> \$0.344 \$0.307	Winter Demand Charge <u>\$/kW/Day</u> \$0.249 \$0.212			
<u>Dist</u> Primary Trans	Demand Charge <u>\$/kW/Mo</u> \$3.980 \$0.000	Dedicated Charge <u>\$/kW/Mo</u> \$3.184 \$0.000	Demand Charge <u>\$/kW/Day</u> \$0.027 \$0.000				

Attachment New Jersey-1 Page 1 of 2

Jersey Central Power & Light Company Standby Rate Model

Brubaker and Associates, Inc. (BAI) has created a model that estimates the monthly charges incurred by a Jersey Central Power & Light Company (Jersey Central) delivery service customer utilizing on-site generation under the Standby Service Rider (STB) for Primary, Transmission, and High Tension Transmission voltage levels. The terms of Rider STB modify the determination of demand and waive the minimum demand charge of the applicable service classifications (supplemental power).

Supplemental power in excess of on-site generation is delivered under applicable service classifications. The two supplemental rate schedules analyzed in the model are: (1) Service Classification GP General Service Primary and (2) Service Classification GT General Service Transmission at both transmission and high tension transmission voltage levels. In addition, there are several applicable riders that are applied to each rate schedule.

The model requires the user to input six fields, either manually or from a drop down list:

- Season (choice of either June through September or October through May);
- Customer's peak demand;
- Customer's load factor;
- Nameplate capacity of the on-site generator;
- Availability of the on-site generator; and
- Maintenance outage hours.

Based on these user-provided inputs, the model determines the amount of energy and power to be charged in two separate categories: the Delivery Service Charges under the general service tariffs and the Standby Demand Charge (SDC) under the standby service rider.

The SDC is the charge that must be paid under the Standby Service Rider. The SDC is equal to the greater of: (1) the Demand Rate times the Billing Demand, plus the Standby Rate times the lesser of the Maximum Monthly facility on-peak kW load or the Annual Average Generation on-peak; or (2) the Standby Rate times the Contract Demand. The definitions of each of the SDC components can be found in the STB Rider on sheet Nos. 50-51.

The Delivery Service Charges consist of the individual charges listed in the supplemental tariff. These charges include the monthly customer charge, the monthly distribution charges which include a demand charge and an energy charge, and the rider charges. There are several rider charges that must be paid based on the amount of delivered energy. The demand charge under the distribution charges will be waived and charged under the Standby Demand Charge.

The model consists of two separate tabs, Inputs and Rates and Charges. The Input tab contains the six input fields described above, along with a summary of the monthly billing units and the standby service tariff units using the same designations that are included in Rider STB.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 77 of 118

Attachment New Jersey-1 Page 2 of 2

The Rates and Charges tab includes the charges associated with the primary, transmission, and high tension transmission voltage levels. Each voltage level is identified in a separate column. Blocks are provided that include the charges, billing units, delivery service charges excluding demand and standby service charges. The standby service charges reflect the demand charges associated with both the on-site generation and the supplemental power consistent with Rider STB. Finally, the charges for each voltage level are summarized and totaled and per unit charges are developed.

Instructions for Using the Model

- 1. On the Inputs tab, the orange boxes must be filled. The season input is a drop down menu, and the other orange boxes must be manually entered.
- 2. To ensure that the file calculates, press F9.
- 3. The model will calculate the charges for each voltage level.
- 4. To evaluate various scenarios, alternative charges or rates need to be inserted in the applicable voltage column in the Rates and Charges tab.

Definition of Inputs

- Season Choose either June through September or October through May.
- **Peak Demand** The maximum demand in kilowatts that is required to fulfill the customer's entire load.
- Load Factor The ratio of average demand to peak demand over a period of time. For this model, that period of time is 730 hours. Can be calculated as the average monthly energy for the season, divided by the peak demand times 730 hours.
- Generator Nameplate Capacity The nameplate capacity of the on-site generator in kilowatts.
- Generator Availability The capacity factor of the generator.
- Generator Maintenance Hours The number of hours in the month in which the generator will be offline due to a planned outage. Must be less than 730 hours. A maximum of two 2-week periods may be allowed per year during the billing months of April, May, June, October, November, or December and must be scheduled six months in advance.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 78 of 118



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 79 of 118

Jersey Central Power & Light Co	omp	Dariy Sta	and	by Rates	
June through September				Voltag	ge Level
Rates as of October 1, 2012	Prir	nary	Tra	nsmission	High Tension Transmission
Delivery Service Charges					
Customer Charge	\$	59.06	\$	243.81	\$ 243.81
Distribution Charges	· ·		· ·		
kW Charge (DR)	\$	6.88	\$	4.67	\$ 3.43
kWh Charge	\$ 0	0.004232	\$	0.003415	\$ 0.002203
Riders					
Non-Utility Generation Charge (Rider NGC) (\$/kWh)	\$ 0	0.002941	\$	0.002885	\$ 0.002826
Transitional Energy Facility Assessment Charge (Rider TEFA) (\$/kWh)	\$ 1	0.001312	\$	0.001029	\$ 0.001029
Societal Benefits Charge (Rider SBC) (\$/kWh)	\$ 1	0.006817	\$	0.006817	\$ 0.006817
Rider CIEP - Standby Fee (\$/kWh)	\$ 1	0.000150	\$	0.000150	\$ 0.000150
System Control Charge (Rider SCC) (\$/kWh)	\$ 1	0.000055	ŝ	0.000055	\$ 0.000055
RGGI Revovery Charge (Rider RRC) (\$/kWh)	15 1	0.000124	\$	0.000124	\$ 0.000124
	1				
Standby Service Charges					
Demand Bate (DB)	\$	6.88	\$	4.67	\$ 3.43
Standby Bate (SB)	ŝ	2.39	ŝ	1 21	\$ 121
onanaoy nato (ony	14	2.00	ŢΨ		· · · · · · · · · · · · · · · · · · ·
Billable Units	Pri	marv	Tra	nsmission	High Tension Transmission
Delivery Service Charges		,			
Customer Charge		1		1	1
Distribution Charges					
kW Charge					
kWb Charge		290 500		290 500	290 500
Bidere		200,000		200,000	200,000
Non-Htility Concration Charge (Rider NGC)		200 500		200 500	200.500
Transitional Energy English Accessment Charge (Rider TEEA)		200,000		200,500	250,500
Societal Reposite Charge (Rider SBC)		290,500		290,500	290,500
Dider CIER Standby Eco		200,000		200,500	200,500
Protom Control Charge (Pider SCC)		290,500		290,500	290,500
DCCI Developer Charge (Rider BDC)		290,500		290,500	290,500
nddi nevovely charge (nider nhc)		290,500		290,500	290,500
Chandles Comies Chernes					
Istandov service Chardes					
Billing Demand (BD)		870		870	870
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""><td></td><td>870 630</td><td></td><td>870 630</td><td>870 630</td></mm>		870 630		870 630	870 630
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>		870 630 700		870 630 700	870 630 700
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>	Pri	870 630 700	Tra	870 630 700	870 630 700
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail</mm>	Pri	870 630 700 mary	Tra	870 630 700	870 630 700 High Tension Transmission
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Cinterer of Deme</mm>	Pri	870 630 700 mary	Tra	870 630 700	870 630 700 High Tension Transmission
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge</mm>	Pri	870 630 700 mary 59	Tra \$	870 630 700 Insmission 244	870 630 700 High Tension Transmission \$ 244
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges</mm>	Pri \$	870 630 700 mary 59	Tra \$	870 630 700 Insmission 244	870 630 700 High Tension Transmission \$ 244
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge</mm>	Prin \$ \$	870 630 700 mary 59	Tra \$ \$	870 630 700 nsmission 244	870 630 700 High Tension Transmission \$ 244 \$
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge</mm>	Prin \$ \$ \$	870 630 700 mary 59 - 1,229	Tra \$ \$ \$	870 630 700 nsmission 244 - 992	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Riders</mm>	Prin \$ \$ \$	870 630 700 mary 59 - 1,229	Tra \$ \$ \$	870 630 700 Insmission 244 - 992	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 001
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Tenetities (Energy Enellity Assessment Charge (Dider TEEA)</mm>	Prii \$ \$ \$	870 630 700 mary 59 - 1,229 854	Tra \$ \$ \$	870 630 700 Insmission 244 - 992 838 838	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 821
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA)</mm>	Pri \$ \$ \$	870 630 700 mary 59 - 1,229 854 381	Tra \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 640 \$ 821 \$ 299 \$ 199
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KWh Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC)</mm>	Prii \$ \$ \$ \$ \$	870 630 700 59 - 1,229 854 381 1,980	Tra \$ \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 821 \$ 229 \$ 1,980
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee Rider CIEP - Standby Fee</mm>	Pril \$ \$ \$ \$ \$ \$ \$	870 630 700 59 - 1,229 854 381 1,980 44	Tra \$ \$ \$ \$ \$ \$	870 630 700 	870 630 700 8 244 8 - 8 640 8 640 8 821 8 299 8 1,980 8 1,980 8 44 8 44
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KWC Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) Offol Demange (Charge (Rider SCC))</mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 59 1,229 854 381 1,980 44 16 226	Tra \$ \$ \$ \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 8219 \$ 229 \$ 1,980 \$ 44 \$ 1980 \$ 44 \$ 1980 \$ 44
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC)</mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 59 1,229 854 381 1,980 44 16 36	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 821 \$ 229 \$ 1,980 \$ 1,980 \$ 44 \$ 16 \$ 36
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Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider SC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*CM or AG) SR*CM or AG) SR*CM</mm>	Pri \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 59 1,229 854 381 1,980 44 16 36 5,986 1,506 1,673 7,491	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 	870 630 7700 High Tension Transmission \$ 244 \$ - \$ 640 \$ 821 \$ 299 \$ 1,980 \$ 44 \$ 198 \$ 360 \$ 2,984 \$ 36 \$ 2,984 \$ 762 \$
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Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR*cMM or AG) SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd]<br="" ag)]="" or="">Charges Incurred - Summary</mm></mm>	Pril \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 59 1,229 854 381 1,980 44 16 36 5,986 1,673 7,491 mary	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$
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Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*cMM or AG) SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd]<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges</mm></mm>	Pri \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 59 1,229 854 381 1,980 44 15,986 1,506 1,673 7,491 mary 59	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 (630 700 (insmission 244 - 992 838 299 1,980 4,063 762 847 4,825 847 4,825 ansmission	870 630 700 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 640 \$ 821 \$ 299 \$ 1,980 \$ 1,980 \$ 36 \$ 2,984 \$ 762 \$ 947 \$ 3,746 High Tension Transmission \$ \$ 244
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*8D SR*<cm ag)<="" or="" td=""> SR*<cm ag)<="" or="" td=""> SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges</mm></cm></cm></mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 59 1,229 854 381 1,980 44 41 6 36 1,506 1,673 7,491 mary 59 1,229	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$ 244 \$
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider SCC) BGGI Service Charges DR*BD SR*<mm ag)<="" or="" td=""> SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders</mm></mm></mm>	Pril \$	870 630 700 59 1,229 854 381 1,980 1,980 1,980 1,598 6 1,673 7,491 5,986 1,573 7,491 59 1,229 3,311	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 (630 700 (1) (244 - 992 8289 239 (2) (2) (4) (4) (6) 36 (3) (6) (4) (4) (6) 36 (3) (6) (4) (4) (6) 36 (3) (2) (4) (4) (2) (4) (2) (4) (2) (2) (2) (2) (2) (2) (2) (2) (2) (2	870 630 700 700 8 244 \$ 4 \$ 4 \$ 4 \$ 4 \$ 44 \$ 44 \$ 299 \$ 44 \$ 299 \$ 44 \$ 36 \$ 298 \$ 44 \$ 3746 High Tension Transmission \$ \$ 244 \$ \$ 3.196
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Distribution Charge Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CIEP - Standby Fee System Contol Charge (Rider SEC) RGBI Revovery Charge (Rider SEC) RGBI Revovery Charge (Rider SEC) SR *<mm ag)<="" or="" td=""> SR *<cm< td=""> SR *<cm< td=""> SR *<cd< td=""> Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges</mm></cd<></cm<></cm<></mm></mm></mm>	Print \$ <td>870 630 700 59 1,229 854 381 1,980 44 16 36 1,506 1,673 7,491 mary 59 1,229 3,311 7,491</td> <td>Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td> <td>870 630 700 </td> <td>870 630 700 High Tension Transmission \$ 244 \$ </td>	870 630 700 59 1,229 854 381 1,980 44 16 36 1,506 1,673 7,491 mary 59 1,229 3,311 7,491	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	870 630 700 	870 630 700 High Tension Transmission \$ 244 \$
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge KW Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIE - Standby Fee System Control Charge (Rider SBC) Rider CIE - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR* SR* Standby Demand Charge (SDC=>{DR*BD}+{SR*<mm [sr*cd]="" ag}]="" or=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges Total Charges Total Charges</mm></mm>	Prii \$	870 630 700 59 1,229 854 381 1,980 44 16 36 5,986 1,673 7,491 mary 59 1,229 3,311 7,491 12,091	Tra \$	870 (630 700 (insmission 244 - 992 888 299 1,980 44 16 36 36 4,063 762 847 4,825 947 244 992 3,213 244 992 3,213 244 992	870 630 700 700 8 244 \$ 5 640 \$ \$ 640 \$
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*cAM or AG) SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm (sr*cd)<="" ag)]="" or="" td=""> Customer Charges Distribution Energy Charges Riders Standby Ocharges Distribution Energy Charges Distribution Energy Charges Distribution Energy Charges Total Charges</mm></mm>	Print \$ <td>870 630 700 mary 59 1,229 854 381 1,980 44 44 16 36 5,986 1,673 7,491 mary 59 1,229 3,311 7,491 12,091</td> <td>Tra \$</td> <td>870 (630 700 (insmission 244 - 992 838 299 1,980 44 6 16 16 16 36 4,063 762 847 4,825 847 4,825 847 4,825 9,274</td> <td>870 630 700 700 8 244 \$ 4 \$ 4 \$ 4 \$ 4 \$ 4 \$ 4 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 9 9 9 9 9 9 9 9 9 9 9 9 10 10 <t< td=""></t<></td>	870 630 700 mary 59 1,229 854 381 1,980 44 44 16 36 5,986 1,673 7,491 mary 59 1,229 3,311 7,491 12,091	Tra \$	870 (630 700 (insmission 244 - 992 838 299 1,980 44 6 16 16 16 36 4,063 762 847 4,825 847 4,825 847 4,825 9,274	870 630 700 700 8 244 \$ 4 \$ 4 \$ 4 \$ 4 \$ 4 \$ 4 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 9 9 9 9 9 9 9 9 9 9 9 9 10 10 <t< td=""></t<>
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CleP - Standby Fee System Control Charge (Rider SBC) Rider Societal Benefits Charge (Rider SCC) RGGI Revovery Charge (Rider SBC) Standby Service Charges DR*BD SR*<dmm ag)<="" or="" td=""> SR*CMM or AG) SR*CMM or AG) Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges Standby Charges Standby Charges Standby Charges Standby Charges Standby Charges</mm></dmm></mm>	Print \$ <td>870 630 700 59 1,229 854 381 1,980 44 16 36 1,506 1,506 1,673 7,491 mary 59 1,229 3,311 7,491 12,091</td> <td>Tra \$</td> <td>870 (630 700 (insmission 244 - 992 838 299 1,980 44 16 36 36 4,063 36 4,063 36 4,063 36 4,063 3,219 2,244 90 2,24 4,825 9,274</td> <td>870 630 700 700 8 244 \$ 5 640 \$ 5 640 \$</td>	870 630 700 59 1,229 854 381 1,980 44 16 36 1,506 1,506 1,673 7,491 mary 59 1,229 3,311 7,491 12,091	Tra \$	870 (630 700 (insmission 244 - 992 838 299 1,980 44 16 36 36 4,063 36 4,063 36 4,063 36 4,063 3,219 2,244 90 2,24 4,825 9,274	870 630 700 700 8 244 \$ 5 640 \$ 5 640 \$

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 80 of 118

Jersey Central Power & Light C	om	pany Sta	and	by Rates	
May through October				Volta	ge Level
Rates as of October 1, 2012	Pri	imary	Tra	nsmission	High Tension Transmission
Delivery Service Charges					
Customer Charge	\$	59.06	\$	243.81	\$ 243.81
Distribution Charges					
KW Charge (DH)	\$	6.37	\$	4.67	\$ 3.43
KWN Charge	\$	0.004232	\$	0.003415	\$ 0.002203
Huers	a .	0.000041	÷	0.000005	¢
Transitional Energy Eaclity Accoccment Charge (Rider TEEA) (\$//Wh)	Ι¢	0.002941	e e	0.002000	\$ 0.002828 \$ 0.001020
Sociatal Banefite Charge (Rider SBC) (\$/W/h)	ι¢	0.001312	¢ ¢	0.006817	\$ 0.001029 \$ 0.006917
Bider CIEP - Standby Fee (\$/kWh)	l š	0.000150	ŝ	0.000150	\$ 0.000150
System Control Charge (Rider SCC) (\$/kWh)	ŝ	0.000055	ŝ	0.000055	\$ 0.000055
RGGI Revovery Charge (Rider RRC) (\$/kWh)	\$	0.000124	\$	0.000124	\$ 0.000124
	1				
Standby Service Charges					
Demand Rate (DR)	\$	6.37	\$	4.67	\$ 3.43
Standby Rate (SR)	\$	2.39	\$	1.21	\$ 1.21
Billable Units	Pri	imary	Tra	nsmission	High Tension Transmission
Delivery Service Charges					
Customer Charge		1		1	1
Distribution Charges					and the second
kW Charge		-		-	-
Rivin Gnarge		290,500		290,500	290,500
Non Lititity Constation Charge (Pider NGC)		200 500		200 500	200 500
Transitional Energy Eaclity Assessment Charge (Rider TEEA)		290,500		290,500	290,500
Societal Benefits Charge (Rider SBC)		290,500		290,500	290,500
Bider CIEP - Standby Fee	1	290,500		290,500	290,500
System Control Charge (Rider SCC)		290,500		290,500	290,500
RGGI Revovery Charge (Rider RRC)		290,500		290,500	290,500
				,	
Standby Service Charges					
Billing Demand (BD)		870		870	870
Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""><td></td><td>630</td><td></td><td>630</td><td>630</td></mm>		630		630	630
Contract Demand (CD)		700		700	700
			-	·····	
Charges incurred - Detail	Pri	imary	Tra	nsmission	High Tension Transmission
Delivery Service Charges					•
Distribution Charges	\$	59	\$	244	\$ 244
kW Charge	¢	_	¢		\$
kWh Charpe	ŝ	1 229	ŝ	992	\$ 640
Riders	1	.,	1		
Non-Utility Generation Charge (Rider NGC)	\$	854	\$	838	\$. 821
Transitional Energy Facility Assessment Charge (Rider TEFA)	\$	381	\$	299	\$ 299
Societal Benefits Charge (Rider SBC)	\$	1,980	\$	1,980	\$ 1,980
Rider CIEP - Standby Fee	\$	44	\$	44	\$ 44
System Control Charge (Rider SCC)	\$	16	\$	16	\$ 16
RGGI Revovery Charge (Rider RRC)	\$	36	\$	36	\$ 36
Standby Caudes Charges					
Standby Service Unarges					
	13	5,542	\$	4,063	2,984
SH < MM OF AG)		1.506	· ·	762	
ISB*CD	e e	1 672	ě	047	⇒ /02 ¢ 047
SR*CD Standby Demand Charge (SDC=>[DP*BD)) (SP*-MM or AG)] or [SP*CD])	\$	1,673	\$	847	\$ 762 \$ 847 \$ 2746
SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR* <mm [sr*cd])<="" ag)]="" or="" th=""><th>\$</th><th>1,673 7,048</th><th>\$ \$</th><th>4,825</th><th>\$ 762 \$ 847 \$ 3,746</th></mm>	\$	1,673 7,048	\$ \$	4,825	\$ 762 \$ 847 \$ 3,746
SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary</mm>	\$ \$ Pri	1,673 7,048 imary	\$ \$ Tra	847 4,825	\$ 762 \$ 847 \$ 3,746 High Tension Transmission
SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary</mm>	\$ \$ Pri	1,673 7,048 imary	\$ \$ Tra	847 4,825 nsmission	\$ 702 \$ 847 \$ 3,746 High Tension Transmission
SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges</mm>	\$ \$ Pri	1,673 7,048 imary 59	\$ Tra	847 4,825 nsmission 244	3 702 \$ 847 \$ 3,746 High Tension Transmission \$ \$ 244
SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges</mm>	S S	1,673 7,048 imary 59 1,229	° \$ Tra \$ \$	847 4,825 nsmission 244 992	\$ 702 \$ 847 \$ 3,746 High Tension Transmission \$ \$ 244 \$ 640
SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Chardes Charges</mm>	Pri SSS	1,673 7,048 imary 59 1,229 3,311 7,042	\$ \$ Tra \$ \$	847 4,825 nsmission 244 992 3,213	3 702 \$ 847 \$ 3,746 High Tension Transmission \$ \$ 244 \$ 640 \$ 3,196
SR*CD Standby Demand Charge (SDC=>[DR*BD]+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Standby Charges</mm>	Pri SSSS	1,673 7,048 imary 59 1,229 3,311 7,048	\$ \$ \$ \$ \$ \$ \$	847 4,825 nsmission 244 992 3,213 4,825	\$ 702 \$ 847 \$ 3,746 High Tension Transmission \$ \$ 244 \$ 640 \$ 3,196 \$ 3,746
SR*CD Standby Demand Charge (SDC=>[DR*BD]+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges</mm>	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	1,673 7,048 imary 59 1,229 3,311 7,048 11,647	\$ \$ \$ \$ \$ \$ \$ \$	847 4,825 nsmission 244 992 3,213 4,825 9,274	S 702 \$ 847 \$ 3,746 High Tension Transmission \$ \$ 244 \$ 640 \$ 3,196 \$ 3,746
SR*CD Standby Demand Charge (SDC=>[DR*BD]+(SR* <mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Standby Charges Standby Charges Standby Charges</mm>	9 5 5 5 5 5 5 5 5 5 5 5 5 5	1,673 7,048 imary 59 1,229 3,311 7,048 11,647 0,04009	\$ \$ Tra \$ \$ \$ \$ \$	847 4,825 nsmission 244 992 3,213 4,825 9,274 0,03122	3 7.02 \$.847 \$.3,746 High Tension Transmission \$ \$.244 \$.640 \$.3,746 \$.3,746 \$.3,746 \$.3,746 \$.7,746 \$.7,746 \$.7,746 \$.7,746

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 81 of 118



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 82 of 118

Jersey Central Power & Light Company Standby Rates					
June through September		Volta	ge Level		
Rates as of October 1, 2012	Primary	Transmission	High Tension Transmission		
Delivery Service Charges					
Customer Charge	\$ 59.06	\$ 243.81	\$ 243.81		
Distribution Charges					
kW Charge (DR)	\$ 6.88	\$ 4.67	\$ 3.43		
kWh Charge	\$ 0.004232	\$ 0.003415	\$ 0.002203		
Biders					
Non-Utility Generation Charge (Rider NGC) (\$/kWh)	\$ 0.002041	\$ 0.002885	\$ 0.002826		
Transitional Energy Eacility Assassment Charge (Rider TEEA) (\$/kWh)	\$ 0.001312	\$ 0.001020	\$ 0.001020		
Sociatal Banefite Charge (Bider SBC) (\$//Wh)	\$ 0.006917	\$ 0.006917	\$ 0.001023		
Didor CIEP - Standby Eco (\$/kWh)	\$ 0.000150	\$ 0.000150	¢ 0.0000170		
Pusters Central Charge (Bides CCC) (MiM/h)	\$ 0.000150	0.000150	\$ 0.000150		
System Control Charge (Rider SCC) (\$rkWh)	\$ 0.000055	\$ 0.000055	\$ 0.000055		
HGGI Revovery Charge (Rider RRC) (\$/kwn)	\$ 0.000124	\$ 0.000124	\$ 0.000124		
Other allow One and a colorest					
Standby Service Charges					
Demand Rate (DR)	\$ 6.88	\$ 4.67	\$ 3.43		
Standby Rate (SR)	\$ 2.39	\$ 1.21	\$ 1.21		
Billable Units	Primary	Transmission	High Tension Transmission		
Delivery Service Charges					
Customer Charge	1	1	1		
Distribution Charges					
kW Charge		-	· · ·		
kWh Charge	824,000	824,000	824,000		
Riders					
Non-Utility Generation Charge (Rider NGC)	824.000	824,000	824.000		
Transitional Energy Facility Assessment Charge (Bider TEFA)	824,000	824,000	824 000		
Societal Benefits Charge (Bider SBC)	824.000	824 000	824,000		
Bider CIEP - Standby Fee	824,000	824,000	824,000		
System Control Charge (Pider SCC)	824,000	824,000	824,000		
PGGI Povovon Charge (Pider BBC)	824,000	824,000	824,000		
	824,000	624,000	824,000		
Standby Service Charges					
Standby Service Charges					
Billing Demand (BD)	2,600	2,600	2,600		
Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""><td>3,400</td><td>3,400</td><td>3,400</td></mm>	3,400	3,400	3,400		
Contract Demand (CD)	4,000	4,000	4,000		
Charges Insurred . Detail	Drimony	Transmission	High Tension Transmission		
Delivery Service Charges	i iiiiai y	Transmission	right relision transmission		
Customer Charges	6 50	C 044	¢		
Customer Charge	\$ 59	\$ 244	\$ 244		
Distribution Charges					
kw Charge	\$ -	15 -	5 -		
kwn Charge		1. 0.044			
IRINERS	\$ 3,487	\$ 2,814	\$ 1,815		
	\$ 3,487	\$ 2,814	\$ 1,815		
Non-Utility Generation Charge (Rider NGC)	\$ 3,487	\$ 2,814 \$ 2,377	\$ 1,815 \$ 2,329		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA)	\$ 3,487 \$ 2,423 \$ 1,081	\$ 2,814 \$ 2,377 \$ 848	\$ 1,815 \$ 2,329 \$ 848		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC)	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC)	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC)	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider SRC)	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 124 \$ 102 \$ 8,918		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*cMM or AG)	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 4,114	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR* <mm ag)<br="" or="">SR*CD</mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider SRC) Standby Service Charges DR*BD SR* <mm ag)<br="" or="">SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd]<="" ag)]="" or="" td=""><td>\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014</td><td>\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256</td><td>\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032</td></mm></mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) System Control Charge (Rider SBC) System Control Charge (Rider SBC) Standby Service Charges DR*BD SR* <mm ag)<br="" or="">SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" th=""><th>\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014</th><th>\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 =</th><th>\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,030</th></mm></mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 =	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,030		
Mon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR* <mm ag)<="" or="" td=""> SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""></mm></mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,660 \$ 26,014 Primary	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 42 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 \$ 16,256	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,440 \$ 13,032 High Tension Transmission		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider SRC) Standby Service Charges SR' <mm ag)<br="" or="">SR'<cd SR'CD Standby Demand Charge (SDC=>[DR'BD)+(SR'<mm [sr'cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges</mm></cd </mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 425 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2,441	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032 High Tension Transmission		
Kon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) RGGI Revovery Charge (Rider SBC) Standby Service Charges DR*BD SR* <mm (sdc="" ag)="" charge="" demand="" or="" sr*<cm="" sr*<mm="" standby="">(DR*BD)+(SR*<mm -="" [sr*cd])="" ag)]="" charges="" charges<="" customer="" incurred="" or="" summary="" td=""><td>\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 599 \$ 2,017</td><td>\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2444 \$ 2,211</td><td>\$ 1,815 2,329 2,32 2,32</td></mm></mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 599 \$ 2,017	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2444 \$ 2,211	\$ 1,815 2,329 2,32 2,32		
Kon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR* <mm (sdc="" ag)="" charge="" demand="" or="" sr*<mm="" standby="">{DR*BD}+(SR*<mm -="" [sr*cd])="" ag)]="" charges="" charges<="" customer="" distribution="" energy="" incurred="" or="" summary="" td=""><td>\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,660 \$ 26,014 Primary \$ 59 \$ 3,487</td><td>\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2,814 \$ 4,57 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 \$ 16,256 \$</td><td>\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 45 \$ 124 \$ 102 \$ \$ 102 \$ 10</td></mm></mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,660 \$ 26,014 Primary \$ 59 \$ 3,487	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2,814 \$ 4,57 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 \$	\$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 45 \$ 124 \$ 102 \$ \$ 102 \$ 10		
Kon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) System Control Charge (Rider SBC) Standby Service Charges DR*BD SR* <mm (sdc="" ag)="" charge="" demand="" or="" sr*<cm="" sr*<mm="" standby="">(DR*BD)+(SR*<mm -="" [sr*cd])="" a<="" ag)]="" charges="" customer="" distribution="" energy="" incurred="" or="" riders="" summary="" td=""><td>\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 59 \$ 3,487 \$ 9,393 \$ 9,393</td><td>\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2444 \$ 2,814 \$ 9,113</td><td>\$ 1,815 2,329 2,32</td></mm></mm>	\$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 59 \$ 3,487 \$ 9,393 \$ 9,393	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2444 \$ 2,814 \$ 9,113	\$ 1,815 2,329 2,32		
Mon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CLEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR* <mm ag)<="" or="" td=""> SR* Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges</mm></mm>	\$ 3,49/ \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 125 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 9,333 \$ 2,014	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 425 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 244 \$ 2,814 \$ 9,113 \$ 16,256	\$ 1,815 1,815 2,329 2,848 2,329 2,848 2,329 2,848 2,5617 2,124 2,445 2,102 2,8 3,918 2,440 3,102 4,144 3,440 3,13,032 4,144 4,440 5,13,032 4,144 5,244 5,244 5,244 5,244 5,244 5,244 5,244 5,39,065 5,244 5,30,322 5,244 5,24		
March March Mon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CLEP - Standby Fee System Control Charge (Rider SBC) RGI Revovery Charge (Rider SBC) System Control Charge (Rider SBC) System Control Charge (Rider SBC) Standby Service Charges DR*BD SR* <mm ag)<="" or="" td=""> SR*<cm ag)<="" or="" td=""> SR*<cd< td=""> Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges</mm></cd<></cm></mm>	\$ 3,447 \$ 2,423 \$ 1,061 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 5,97 \$ 3,487 \$ 9,930 \$ 26,014 \$ 3,820,144 \$ 38,050	\$ 2,814 \$ 2,377 \$ 484 \$ 5,617 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 244 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 5,617 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 \$ 28,427 \$ 28,427	\$ 1,815 \$ 2,329 \$ 48 5 5,617 \$ 124 \$ 5 102 \$ \$ 45 5 102 \$ 13,032 \$ 244 \$ 13,032 \$ 244 \$ 5 13,032 \$ 24,156 \$ 13,032 \$ 24,156 \$ 13,032 } \$ 24,156 \$ 13,032 \$ 24,156 } }		
Kon-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Standby Service Charges DR*BD SR*-KMM or AG) SR*-CMM or AG) SR*-CMM or AG) SR*-CMM or AG) Standby Demand Charge (SDC=>(DR*BD)+(SR* <mm -="" [sr*cd])="" ag)]="" charges="" charges<="" customer="" distribution="" energy="" incurred="" or="" riders="" standby="" summary="" td="" total=""><td>\$ 3,497 \$ 2,423 \$ 1,061 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 26,014 Primary \$ 5,93 \$ 26,014 \$ 9,333 \$ 26,014 \$ 3,487 \$ 9,333 \$ 26,014 \$ 3,487 \$ 3,8953 \$ 26,014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 3,607 \$ 3,8953 \$ 3,6075 \$ 3,8953 \$ 3,6075 \$ 3,8953 \$ 3,8953 \$ 3,6075 \$ 3,60755 \$ 3,60755 \$ 3,607555 \$ 3,607555555</td><td>\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2,844 \$ 9,113 \$ 16,256 \$ 28,427</td><td>\$ 1,815 2,329 2,32</td></mm>	\$ 3,497 \$ 2,423 \$ 1,061 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 26,014 Primary \$ 5,93 \$ 26,014 \$ 9,333 \$ 26,014 \$ 3,487 \$ 9,333 \$ 26,014 \$ 3,487 \$ 3,8953 \$ 26,014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 2,6014 \$ 3,8953 \$ 3,607 \$ 3,8953 \$ 3,6075 \$ 3,8953 \$ 3,6075 \$ 3,8953 \$ 3,8953 \$ 3,6075 \$ 3,60755 \$ 3,60755 \$ 3,607555 \$ 3,607555555	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 45 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2,844 \$ 9,113 \$ 16,256 \$ 28,427	\$ 1,815 2,329 2,32		
Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) RGGI Revovery Charge (Rider SBC) Standby Service Charges DR*BD SR* <mm ag)<br="" or="">SR*CD Standby Demand Charge (SDC=>{DR*BD}+(SR*<mm (sr*cd))<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges S/kWM (Delivered Energy)</mm></mm>	\$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 17,888 \$ 8,126 \$ 9,560 \$ 26,014 Primary \$ 9,560 \$ 26,014 Primary \$ 3,487 \$ 9,393 \$ 26,014 \$ 38,953 \$ 0,04727	\$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 4,840 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 \$ 28,427 \$ 0,03450	\$ 1,815 1,232 2,329 2,445 2,329 2,414 2,445 2,445 2,445 2,445 2,445 2,445 3,13,032 4,144 3,4,840 3,13,032 4,155 3,9,085 3,13,032 2,445 4,145 3,13,032 4,156 5,13,032 5,24,156 5,24 5,24 5,24 5,24 5,24 5,24 5,24 5,24		

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 83 of 118

Jersey Central Power & Light Company Standby Rates						
May through October		Volta	ge Level			
Rates as of October 1, 2012	Primary	Transmission	High Tension Transmission			
Delivery Service Charges						
Customer Charge	\$ 59.06	\$ 243.81	\$ 243.81			
Distribution Charges						
kW Charge (DR)	\$ 6.37	\$ 4.67	\$ 3.43			
kWh Charge	\$ 0.004232	\$ 0.003415	\$ 0.002203			
Riders						
Non-Utility Generation Charge (Rider NGC) (\$/kWh)	\$ 0.002941	\$ 0.002885	\$ 0.002826			
Transitional Energy Facility Assessment Unarge (Hider TEFA) (\$/kwn)	\$ 0.001312	\$ 0.001029	\$ 0.001029			
Societal Benefits Charge (Hider SBC) (\$/kwn)	\$ 0.006817	\$ 0.006817	\$ 0.006817			
Rider CIEP - Standby Fee (\$/KWN)	\$ 0.000150	\$ 0.000150	\$ 0.000150			
System Control Charge (Rider SCC) (\$/kW/h)	\$ 0.000055	\$ 0.000055	\$ 0.000055			
nddi nevovery charge (nider nnc) (\$/kwin)	\$ 0.000124	\$ 0.000124	\$ 0.000124			
Standby Service Charges						
Demand Pate (DP)	¢ 6.27	¢ 467	¢			
Standby Bate (SB)	\$ 2.39	\$ 1.07	\$ 1.45			
Standby rideo (Srij	φ <u>2.00</u>	φ 1.2.1	\$ (.21)			
Billable Units	Primary	Transmission	High Tension Transmission			
Delivery Service Charges						
Customer Charge	1	1	1			
Distribution Charges						
kW Charge	-	- 1	-			
kWh Charge	824,000	824,000	824,000			
Riders						
Non-Utility Generation Charge (Rider NGC)	824,000	824,000	824,000			
Transitional Energy Facility Assessment Charge (Rider TEFA)	824,000	824,000	824,000			
Societal Benefits Charge (Rider SBC)	824,000	824,000	824,000			
Rider CIEP - Standby Fee	824,000	824,000	824,000			
System Control Charge (Rider SCC)	824,000	824,000	824,000			
RGGI Revovery Charge (Rider RRC)	824,000	824,000	824,000			
Standby Service Charges						
Billing Demand (BD)	2,600	2,600	2,600			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""><td>2,600 3,400</td><td>2,600 3,400</td><td>2,600 3,400</td></mm>	2,600 3,400	2,600 3,400	2,600 3,400			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>	2,600 3,400 4,000	2,600 3,400 4,000	2,600 3,400 4,000			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>	2,600 3,400 4,000	2,600 3,400 4,000	2,600 3,400 4,000			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Deliverv Service Charges</mm>	2,600 3,400 4,000 Primary	2,600 3,400 4,000	2,600 3,400 4,000 High Tension Transmission			
Billing Domand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge</mm>	2,600 3,400 4,000 Primary	2,600 3,400 4,000	2,600 3,400 4,000 High Tension Transmission			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges</mm>	2,600 3,400 4,000 Primary \$ 59	2,600 3,400 4,000 Transmission \$ 244	2,600 3,400 4,000 High Tension Transmission \$ 244			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge</mm>	2,600 3,400 4,000 Primary \$ 59 \$ -	2,600 3,400 4,000 Transmission \$ 244 \$ -	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ -			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815			
Silling Demand (BD) Minimum of Max Monthily demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KWh Charge Riders</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815			
Billing Domand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges kW Charge Riders Non-Utilly Generation Charge (Rider NGC)</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 2,377	2,600 3,400 4,000 \$ 244 \$. \$ 1,815 \$ 2,329			
Billing Demand (BD) Minimum of Max Monthily demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA)</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 848	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Bilding KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC)</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 848 \$ 5,617	2,600 3,400 4,000 High Tension Transmission \$ 2,44 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee</mm>	2,600 3,400 4,000 \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124			
Billing Demand (BD) Minimum of Max Monthily demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SC)</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45	2,600 3,400 4,000 Transmission \$ 2,44 \$ - \$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 124			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SGC) Rider CLEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC)</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102	2,600 3,400 4,000 \$ 244 \$ 2,814 \$ 3,600 \$ 2,814 \$ 3,600 \$ 3,600 \$ 2,814 \$ 3,600 \$ 3,600 \$ 2,814 \$ 3,600 \$ 3,600\$ \$ 3,	2,600 3,400 4,000			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) Rider SCEP - Standby Fee System Control Charge (Rider SCC) RiGGI Revovery Charge (Rider SCC) RiGGI Revovery Charge (Rider SCC)</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 5,617 \$ 124 \$ 45 \$ 102	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 124 \$ 124			
Billing Demand (BD) Minimum of Max Monthily demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DECED</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 102 \$ 16,652	2,600 3,400 4,000 Transmission \$ 2,44 \$ - \$ 2,814 \$ 2,814 \$ 2,317 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,122	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 102 \$ 0,018			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Bilderg Non-Utilly Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider SC) Rider Service Charge (Rider RBC) Standby Service Charges DR*BD SB*rdM or AG)</mm>	2,600 3,400 4,000 \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 8,105	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 5,617 \$ 848 \$ 5,617 \$ 124 \$ 455 \$ 12,142 \$ 4,114	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 124 \$ 102 \$ 102 \$ 4114			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Gustomer Charge KW Charge Bidges Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider RBC) Standby Service Charges DR*BD SR*CD SR*CD</mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 16,562 \$ 16,562 \$ 16,562 \$ 5 9 \$ 561	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 124 \$ 45 \$ 102 \$ 12,142 \$ 12,142 \$ 4,214	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 124 \$ 124 \$ 102 \$ 8,918 \$ 4,114 \$ 4,600			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge kW Charge kW Charge Riders Non-Utility Generation Charge (Rider NGC) Non-Utility Generation Charge (Rider NGC) Non-Utility Generation Charge (Rider NGC) Non-Utility Generation Charge (Rider NGC) Non-Utility Generation Charge (Rider SCC) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Contol Charge (Rider SCC) Rider SCD Standby Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CM Pemand Charge (SDC=>/IDR*BD)+(SR*<mm ag)]="" isr*cd)<="" or="" td=""><td>2.600 3.400 4.000 \$ \$ 5 \$ \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ \$ 5.8,126 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 4,114 \$ 12,142 \$ 4,114 \$ 12,142 \$ 4,840 \$ 6,266</td><td>2,600 3,400 4,000 High Tension Transmission \$ 2,44 \$ 1,815 \$ 2,329 \$ 8,488 \$ 5,617 \$ 2,329 \$ 8,488 \$ 5,617 \$ 124 \$ 5,617 \$ 5,617 \$ 124 \$ 5,617 \$ 5,617\$ \$ 5,617\$ 5,617\$ 5,617\$ \$ 5,617</td></mm></mm></mm>	2.600 3.400 4.000 \$ \$ 5 \$ \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ \$ 5.8,126 \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 12,142 \$ 4,114 \$ 12,142 \$ 4,114 \$ 12,142 \$ 4,840 \$ 6,266	2,600 3,400 4,000 High Tension Transmission \$ 2,44 \$ 1,815 \$ 2,329 \$ 8,488 \$ 5,617 \$ 2,329 \$ 8,488 \$ 5,617 \$ 124 \$ 5,617 \$ 5,617 \$ 124 \$ 5,617 \$ 5,617\$ \$ 5,617\$ 5,617\$ 5,617\$ \$ 5,617			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Distribution Charge Riders KW Charge Riders Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider SC) Rider SC) Rider SC) Rider SBC System Control Charge (Rider SBC) Rider SBC) Rider SBC System Control Charge (Rider SBC) System Control Charge (SBC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" th=""><th>2.600 3.400 4.000 \$ 59 \$ - \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.617 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 102 \$ 16,562 \$ 102 \$ 24,688</th><th>2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 1,244 \$ 4,55 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256</th><th>2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032</th></mm></mm>	2.600 3.400 4.000 \$ 59 \$ - \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.617 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 102 \$ 16,562 \$ 102 \$ 24,688	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 1,244 \$ 4,55 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Customer Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary</mm></mm>	2.600 3.400 4.000 Primary \$ 59 \$ - \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.817 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 8,126 \$ 9.566 \$ 24,688 Primary	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 45 \$ 102 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 16,256 Transmission	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 4,5 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032 High Tension Transmission			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Biders KW Charge Biders Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Contol Charge (Rider SBC) Rider SC) Rider Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CD Standby Demand Charge (SDC=>[DR*BD]+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary</mm></mm></mm>	2.600 3.400 4.000 \$ 59 \$ - 3,487 \$ 2.423 \$ 1.081 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ 5.622 \$ 8.126 \$ 9.560 \$ 24.688 Primary	2,600 3,400 4,000 Transmission \$ 244 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,377 \$ 848 \$ 5,617 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 8,488 \$ 5,617 \$ 2,329 \$ 8,488 \$ 5,617 \$ 124 \$ 5,517 \$ 124 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 4,840 \$ 13,032 High Tension Transmission			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider SC) Rider SC) Standby Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges</mm></mm></mm>	2.600 3.400 4.000 \$ 59 \$ - \$ 3.487 \$ 1,081 \$ 5,817 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 16,562 \$ 16,562 \$ 16,562 \$ 24,688 Primary \$ 59	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 124 \$ 4,5 \$ 124 \$ 45 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 12,142 \$ 2,814 \$ 2,814 \$ 2,814 \$ 12,142 \$ 12,142 \$ 12,142 \$ 2,814 \$ 2,244 \$ 2,244 \$ 2,244 \$ 2,484 \$ 2,244 \$ 2,244 \$ 3,256 \$ 12,142 \$ 3,256 \$ 12,256 \$ 3,256 \$ 3,2566\$ \$ 3,2566\$ \$ 3,2566\$ \$ 3,2666\$ \$ 3,2666\$ \$ 3,2666\$ \$ 3,2666\$ \$ 3,2666\$ \$	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 5,617 \$ 124 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 13,032 High Tension Transmission \$ 244			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Riders Non-Utility Generation Charge (Rider NGC) Non-Utility Generation Charge (Rider SCC) Rodetal Benefits Charge (Rider SEC) System Contol Charge (Rider SCC) RGGI Revovery Charge (Rider SCC) RGGI Revovery Charge (Rider SCC) Standby Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CM Mor AG) SR*CM Mor AGA SR*CM Mor AG) SR*CM Mor AGA SR*CM MOR MOR AGA SR*CM MOR MOR MOR MOR MOR MOR MOR MOR MOR MO</mm></mm>	2,600 3,400 4,000 Primary \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,817 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 16,562 \$ 44,58 \$ 0,5660 \$ 24,688 Primary \$ 59 \$ - \$ 3,487	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 4,5 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 244 \$ 2,814	2,600 3,400 4,000 High Tension Transmission \$ 2,44 \$. \$ 1,815 \$ 2,329 \$ 8,48 \$ 5,617 \$ 2,329 \$ 8,48 \$ 5,617 \$ 1,24 \$ 5,617 \$ 1,24 \$ 5,617 \$ 1,25 \$ 2,329 \$ 8,48 \$ 5,617 \$ 1,24 \$ 5,617 \$ 1,25 \$ 2,329 \$ 8,48 \$ 5,617 \$ 1,24 \$ 5,617 \$ 1,25 \$ 2,329 \$ 8,48 \$ 5,617 \$ 1,25 \$ 2,329 \$ 8,48 \$ 1,24 \$ 5,617 \$ 1,25 \$ 2,329 \$ 3,517 \$ 1,24 \$ 5,617 \$ 1,24 \$ 1,25 \$ 3,517 \$ 3,51			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Bilders KW Charge Riders Non-Utilly Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider SC) Rider Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CM or AG) SR*CM or AG) SR*CM or AG) SR*CM or AG) SR*CM or AG] Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Riders</mm></mm>	2.600 3.400 4.000 \$ 59 \$ - \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.817 \$ 124 \$ 45 \$ 102 \$ 16.562 \$ 8.126 \$ 9.560 \$ 24.688 Primary \$ 5.93 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	2,600 3,400 4,000 \$ 244 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 5,617 \$ 12,142 \$ 4,114 \$ 16,256 Transmission \$ 244 \$ 4,840 \$ 16,256 Transmission \$ 244 \$ 9,113	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 8,488 \$ 5,617 \$ 2,329 \$ 8,488 \$ 5,617 \$ 1,815 \$ 0,020 \$ 8,918 \$ 4,114 \$ 4,840 \$ 1,3,032 High Tension Transmission \$ 2,244 \$ 4,114 \$ 4,840 \$ 4,114 \$ 4,114 \$ 4,840 \$ 4,114 \$ 4,840 \$ 4,114 \$ 4,114 \$ 4,840 \$ 4,114 \$ 4,840 \$ 4,114 \$ 4,940 \$ 4,114 \$ 4,940 \$ 4,114 \$ 4,940 \$ 4,114 \$ 4,940 \$ 4,926 \$ 4,114 \$ 4,940 \$ 4,			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Ridars Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Pittlers Standby Charges</mm></mm>	2.600 3.400 4.000 \$ 59 \$ - \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.817 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 8,126 \$ 9,560 \$ 24,688 Primary \$ 59 \$ 3.487 \$ 9.939 \$ 9.339 \$ 9.4688	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 5,617 \$ 124 \$ 4,5 \$ 102 \$ 12,142 \$ 4,5 \$ 102 \$ 12,142 \$ 4,5 \$ 16,256 Transmission \$ 244 \$ 4,840 \$ 16,256	2,600 3,400 4,000 High Tension Transmission \$ 244 \$ - \$ 1,815 \$ 2,329 \$ 848 \$ 5,617 \$ 124 \$ 5,124 \$ 102 \$ 8,918 \$ 4,114 \$ 4,50 \$ 13,032 High Tension Transmission \$ 2,44 \$ 9,665 \$ 9,065			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Riders KW Charge Biders Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider SCC) Standby Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges</mm></mm></mm>	2.600 3.400 4.000 \$ 59 \$ - 3.487 \$ 2.423 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ 5.617 \$ 124 \$ 5.622 \$ 8.126 \$ 9.560 \$ 5.8,126 \$ 9.569 \$ 5.99 \$ - 5.00 \$ - 9.200 \$ - 9.200 \$ - 9.200 \$ - 9.200 \$ - 9.200 \$ - 9.200 \$ - 9.200 \$ - 9.99 \$ - 9.500 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.509 \$ - 9.999 \$ - 9.999 \$ - 9.509 \$ - 9.999 \$ - 9.709 \$ - 9.999 \$ - 9.999 \$ - 9.999 \$ - 9.999 \$ - 9.709 \$ - 9.999 \$ \$ - 9.999 \$ - 9.999 \$ - 9.999 \$ 9.999 \$ - 9.999 \$ - 9 \$ - 9 \$ 9.999 \$ 9.999 \$ 9 \$ 9 \$ 9 \$ 9 \$ 9 \$	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,377 \$ 2,814 \$ 2,377 \$ 2,814 \$ 5,617 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,266 \$ 28,427 \$ 2,814 \$ 3,628 \$ 2,814 \$ 3,628 \$ 2,814 \$ 4,840 \$ 6,8427 \$ 2,814 \$ 2,814 \$ 3,628 \$ 3,628 \$ 2,814 \$ 4,840 \$ 6,8427 \$ 2,814 \$ 2,814 \$ 3,628 \$ 3,628 \$ 3,8427 \$ 3,8427 \$ 3,848 \$ 3,617 \$ 3,848 \$ 3,848 \$ 3,848 \$ 3,848 \$ 3,848 \$ 3,848 \$ 3,848\$ \$ 3	2,600 3,400 3,400 4,000 High Tension Transmission \$ 2,44 \$. \$ 1,815 \$ 2,329 \$ 8,488 \$ 5,617 \$ 2,329 \$ 8,488 \$ 5,617 \$ 1,244 \$ 5,617 \$ 1,24 \$ 5,617 \$ 1,24 \$ 5,617 \$ 1,24 \$ 3,032 High Tension Transmission \$ 2,44 \$ 1,815 \$ 0,065 \$ 13,032 \$ 2,4156 \$ 2,4156 \$ 2,4156 \$ 2,4156 \$ 2,4156 \$ 3,018 \$ 3,0			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Riders KW Charge Riders Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider SC) Rider SC) Rider SC) Rider SC) Standby Service Charges DR*bD SR*cMM or AG) SR*cD Standby Demand Charge (SDC=>[DR*bD)+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges</mm></mm>	2,600 3,400 4,000 \$ 59 \$ - \$ 3,487 \$ 2,423 \$ 1,081 \$ 5,817 \$ 124 \$ 102 \$ 16,562 \$ 125 \$ 102 \$ 125 \$ 124 \$ 45 \$ 3,487 \$ 9,350 \$ - \$ 3,487 \$ 3,487 \$ 3,487 \$ 3,487 \$ 3,487 \$ 3,487 \$ 3,475 \$ 124,688 \$ 3,7627	2,600 3,400 4,000 Transmission \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 2,814 \$ 124 \$ 4,56 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 2,844 \$ 9,113 \$ 16,256 \$ 28,427	2,600 3,400 4,000 High Tension Transmission \$ 244 \$. \$ 1,815 \$ 2,329 \$ 8,818 \$ 5,617 \$ 2,329 \$ 8,848 \$ 5,617 \$ 124 \$ 102 \$ 102 \$ 8,918 \$ 4,114 \$ 4,816 \$ 4,400 \$ 2,415 \$ 9,065 \$ 13,032 \$ 24,156			
Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge Riders KW Charge Riders Non-Utility Generation Charge (Rider NGC) Non-Utility Generation Charge (Rider SCC) Rodeltal Benefits Charge (Rider SEC) System Contol Charge (Rider SCC) RGGI Revovery Charge (Rider SCC) RGGI Revovery Charge (Rider SCC) Standby Service Charges DR*BD SR*<mm ag)<br="" or="">SR*CM or AG) SR*CM Mor AG) SR*CM Mor AG) SR*CM Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm [sr*cd])<br="" ag)]="" or="">Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges</mm></mm></mm>	2.600 3.400 4.000 Primary \$ 59 \$ - \$ 3.487 \$ 2.423 \$ 1.081 \$ 5.817 \$ 124 \$ 45 \$ 102 \$ 16,562 \$ 45 \$ 102 \$ 16,562 \$ 3,487 \$ 24,688 Primary \$ 59 \$ 3.487 \$ 9.359 \$ 3.487 \$ 9.333 \$ 24,688 \$ 3.487 \$ 9.333 \$ 24,688 \$ 3.3,477 \$ 0.04566 \$ 0.00566 \$ 0.04566 \$ 0.000 \$ 0.04566 \$ 0.045666 \$ 0.045666 \$ 0.0456666 \$ 0.04566666666666666666666666666	2,600 3,400 4,000 \$ 244 \$ - \$ 2,814 \$ 2,814 \$ 2,814 \$ 4,5 \$ 102 \$ 12,142 \$ 4,114 \$ 4,840 \$ 16,256 Transmission \$ 244 \$ 2,814 \$ 4,814 \$ 16,256 \$ 16,256 \$ 28,427 \$ 0,03450 \$ 2,814	2,600 3,400 4,000 High Tension Transmission \$ 2,44 \$. \$ 1,815 \$ 2,329 \$ 8,48 \$ 5,617 \$ 2,329 \$ 8,48 \$ 5,617 \$ 124 \$ 5,124 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 102 \$ 8,918 \$ 4,114 \$ 4,840 \$ 10,022 High Tension Transmission \$ 2,445 \$ 0,02932 \$			

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 84 of 118



Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 85 of 118

Jersey Central Power & Light Company Standby Rates					
June through September		Volta	ge Level		
Rates as of October 1, 2012	Primary	Transmission	High Tension Transmission		
Delivery Service Charges					
Customer Charge	\$ 59.06	\$ 243.81	\$ 243.81		
Distribution Charges					
kW Charge (DR)	\$ 6.88	\$ 4.67	\$ 3.43		
kWh Charge	\$ 0.004232	\$ 0.003415	\$ 0.002203		
Hiders	¢ 0.0000.41	¢ 0.000005	* 0.000000		
INon-Utility Generation Charge (Rider NGC) (\$/kwn)	\$ 0.002941	\$ 0.002885	\$ 0.002826		
Fransitional Energy Facility Assessment Charge (Hider TEFA) (\$/kwn)	\$ 0.001312	\$ 0.001029	\$ 0.001029		
Dider CIED - Standby Eco (\$/(W/b)	\$ 0.0000150	\$ 0.000150	\$ 0.000517		
Protein Centrel Charge (Bider SCC) (\$///Wh)	\$ 0.000150	\$ 0.000150 \$ 0.000055	\$ 0.000150		
BCCL Pavovaru Charge (Rider BBC) (\$/kWh)	\$ 0.000033	\$ 0.000000	\$ 0.000033		
(article revovery charge (nider nnc) (artight)	\$ 0.000124	φ 0.000124	φ 0.000124		
Standby Service Charges					
Demand Bate (DB)	\$ 6.88	\$ 4.67	\$ 3.43		
Standby Bate (SB)	\$ 2.39	\$ 1.21	\$ 1.21		
	14 -935				
Billable Units	Primary	Transmission	High Tension Transmission		
Delivery Service Charges					
Customer Charge	1	1	1		
Distribution Charges					
kW Charge	-	-	-		
kWh Charge	2,425,000	2,425,000	2,425,000		
Riders					
Non-Utility Generation Charge (Rider NGC)	2,425,000	2,425,000	2,425,000		
Transitional Energy Facility Assessment Charge (Rider TEFA)	2,425,000	2,425,000	2,425,000		
Societal Benefits Charge (Rider SBC)	2,425,000	2,425,000	2,425,000		
Rider CIEP - Standby Fee	2,425,000	2,425,000	2,425,000		
System Control Charge (Rider SCC)	2,425,000	2,425,000	2,425,000		
RGGI Revovery Charge (Rider RRC)	2,425,000	2,425,000	2,425,000		
		1			
Standby Service Charges					
Standby Service Charges Billing Demand (BD)	12,000	12,000	12,000		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""><td>12,000 18,000</td><td>12,000 18,000</td><td>12,000 18,000</td></mm>	12,000 18,000	12,000 18,000	12,000 18,000		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>	12,000 18,000 20,000	12,000 18,000 20,000	12,000 18,000 20,000		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail</mm>	12,000 18,000 20,000	12,000 18,000 20,000	12,000 18,000 20,000		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges</mm>	12,000 18,000 20,000 Primary	12,000 18,000 20,000 Transmission	12,000 18,000 20,000 High Tension Transmission		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge</mm>	12,000 18,000 20,000 Primary \$ 59	12,000 18,000 20,000 Transmission \$ 244	12,000 18,000 20,000 High Tension Transmission \$ 244		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges</mm>	12,000 18,000 20,000 Primary \$ 59	12,000 18,000 20,000 Transmission \$ 244	12,000 18,000 20,000 High Tension Transmission \$ 244		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge</mm>	12,000 18,000 20,000 Primary \$ 59 \$ -	12,000 18,000 20,000 Transmission \$ 244 \$ -	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ -		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KWh Charge</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KWh Charge Riders Non-Utility Generation Charge (Rider NGC)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Nor-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 16,531	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges kWh Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIF - Standby Fee</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 16,531 \$ 364	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Contor Charge (Rider SCC)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 16,531 \$ 364 \$ 133	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 16,531 \$ 364 \$ 133	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 133		
Standby Service Charges Silling Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SGC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 3,182 \$ 16,531 \$ 364 \$ 133 \$ 301	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 3133 \$ 301	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 6,853 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 301		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIE P. Standby Fee System Control Charge (Rider RRC) Charge (Rider RRC) Charge (Rider RRC)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 16,531 \$ 364 \$ 133 \$ 301	12,000 18,000 20,000 \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 364 \$ 301		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Riders Riders Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CLEP - Standby Fee System Contol Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges Database</mm>	12,000 18,000 20,000 \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,01 \$ 301	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 5,000	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 41460		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Control Charges (Rider SCC) Rider SCC) Standby Service Charges DR*BD CPI: All ex (P)</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,162 \$ 3,162 \$ 3,162 \$ 364 \$ 133 \$ 301 \$ 82,560 \$ 42,050	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 3301 \$ 364 \$ 3301 \$ 301	12,000 18,000 20,000 High Tension Transmission \$ 244 \$		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (-MM or AG) Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider Clifer - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR* <mm ag)<="" or="" td=""> SR*<mm ag)<="" or="" td=""></mm></mm>	12,000 18,000 18,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,162 \$ 16,531 \$ 36,531 \$	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 331 \$ 301 \$ 56,040 \$ 21,780 \$ 24,207 \$ 301 \$	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 41,160 \$ 21,780 \$ 24,200		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders Riders Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CLEP - Standby Fee System Contol Charge (Rider SBC) Rider SBC System Contol Charge (Rider RRC) Standby Service Charges DR*BD SR*<mm ag)<="" or="" td=""> SR*<demand (sdc="" charge="">1DR*BD)+(SB*<mm (sb*cd)<="" agi)="" or="" td=""></mm></demand></mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 82,560 \$ 43,020 \$ 47,800 \$ 125,580	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 363 \$ 301 \$ 56,040 \$ 21,780 \$ 24,205 \$ 301 \$ 301 \$ 54,205 \$ 301 \$ 301 \$ 301 \$ 556,040 \$ 21,780 \$ 24,205 \$ 301 \$ 301	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 41,160 \$ 21,780 \$ 24,200		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider Cler - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*<cmm ag)<="" or="" td=""> SR*CMM or AG) SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""></mm></cmm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,16,531 \$ 364 \$ 133 \$ 301 \$ 82,560 \$ 47,800 \$ 125,580	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 56,040 \$ 21,780 \$ 24,200 \$ 77,820	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ \$		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider Cler - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR*<cm ag)<="" or="" td=""> SR*<cm ag)<="" or="" td=""> SR*CMM or AG) SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd]<="" ag)]="" or="" td=""></mm></cm></cm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 10,263 \$ 7,132 \$ 3,162 \$ 10,263 \$ 3,162 \$ 3,162 \$ 3,162 \$ 3,162 \$ 43,020 \$ 43,020 \$ 43,020 \$ 43,020 \$ 125,580 Primary	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 333 \$ 301 \$ 56,040 \$ 21,780 \$ 21,780 \$ 21,7820 Transmission	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 3133 \$ 3011 \$ 41,160 \$ 24,200 \$ 62,940 High Tension Transmission		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Clustomer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Contol Charge (Rider SCC) RGa Revovery Charge (Rider SCC) Standby Service Charges DR*BD SR*<mm ag)<="" or="" td=""> SR*<mm ag)<="" or="" td=""> Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary</mm></mm></mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,6531 \$ 3,65311 \$ 3,653111	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 56,040 \$ 21,780 \$ 24,200 Transmission	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 2,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 301 \$ 21,780 \$ 24,200 \$ 62,940 High Tension Transmission 24,200		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charges Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC) Standby Service Charges DR*BD SR*CMM or AG) SR*CM or AG SR*CD Standby Demand Charge (SDC=>(DR*BD)+(SR*<mm (sr*cd)<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges</mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 364 \$ 16,531 \$ 364 \$ 13,33 \$ 301 \$ 82,560 \$ 43,020 \$ 47,800 \$ 47,800 \$ 47,800 \$ 42,560 \$ 47,800 \$ 47,800 \$ 47,800 \$ 47,800 \$ 47,800 \$ 47,800 \$ 47,800 \$ 59 \$ 43,020 \$ 47,800 \$ 47,800 \$ 59 \$ 45,560 \$ 47,800 \$ 59 \$ 50 \$ 50	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 138 \$ 301 \$ 56,040 \$ 21,780 \$ 24,200 \$ 77,820 Transmission \$ 24,200 \$ 2,77,820 \$ 2,6,040 \$ 2,77,820 \$ 2,77,820 \$ 2,6,040 \$ 2,77,820 \$ 3,6,040 \$ 2,6,040 \$ 3,77,820 \$ 3,6,040 \$ 3,77,820 \$ 3,	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 244 \$ - \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge W Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider Clifer - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR*cMM or AG) SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges</mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 16,531 \$ 3,182 \$ 3,182 \$ 16,531 \$ 3,182 \$ 3,182 \$ 125,560 Primary \$ 59 \$ 10,263 \$ 7,132 \$ 3,182 \$ 1,133 \$ 301 \$ 125,560 Primary \$ 59 \$ 10,263 \$ 7,132 \$ 3,182 \$ 10,263 \$ 7,132 \$ 3,182 \$ 10,263 \$ 7,132 \$ 3,182 \$ 10,263 \$ 10,263 \$ 7,132 \$ 3,182 \$ 10,263 \$ 10,2	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 331 \$ 301 \$ 56,040 \$ 21,780 \$ 24,200 Transmission \$ 24,200 \$ 77,820 Transmission \$ 24,200 \$ 21,200 \$ 20,000 \$ 20,000 \$ 24,200 \$ 300 \$ 3000 \$ 3000 \$ 3	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,853 \$ 364 \$ 3133 \$ 3011 \$ 21,780 \$ 24,200 \$ 2,420 \$ 2,840 High Tension Transmission \$ 2,840		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Qustomer Charge Riders Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CIEP - Standby Fee System Control Charge (Rider SEC) RGGI Revovery Charge (Rider SEC) Standby Service Charges DR*BD SR*<mm ag)<="" or="" td=""> SR*<cd< td=""> Standby Demand Charge (SDC=>[DR*BD]+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Charges Incurred - Summary</mm></cd<></mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 3,210 \$ 3,182 \$ 3,210 \$ 43,020 \$ 42,560 \$ 7,782 \$ 7,783 \$ 7,782 \$ 7,783 \$ 7,782 \$ 7,783 \$ 7,784 \$	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 56,040 \$ 24,200 \$ 24,200 \$ 77,820 Transmission \$ 244 \$ 36,996 \$ 2,495 \$ 16,531 \$ 364 \$ 366 \$ 24,205 \$ 16,531 \$ 366 \$	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 2,940		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider Cler - Standby Fee System Control Charge (Rider RRC) Standby Service Charge (Bider RRC) Standby Service Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd]<="" ag)]="" or="" td=""> SR*CD Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd]<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges</mm></mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 10,263 \$ 7,132 \$ 3,162 \$ 10,263 \$ 3,162 \$ 3,162 \$ 3,162 \$ 47,800 \$ 125,580 Primary \$ 59 \$ 10,263 \$ 43,020 \$ 44,020 \$ 125,580 Primary \$ 2,646 \$ 2,560 \$ 2,660 \$ 2,600 \$ 2,660 \$ 3,600 \$ 3,6000 \$ 3,6000 \$ 3,6000 \$ 3,6000 \$ 3,60000 \$ 3,6000	12,000 18,000 18,000 20,000 Transmission \$ \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 364 \$ 21,780 \$ 24,200 \$ 77,820 Transmission \$ \$ 26,821 \$ 26,821 \$ 26,821 \$ 26,821 \$ 244 \$ 26,821 \$ 26,821 \$ 26,821 \$ 26,821 \$ 26,821 \$ 26,821 \$ 26,821 \$ 24,414	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 364 \$ 3133 \$ 21,780 \$ 24,200 \$ 62,940 High Tension Transmission \$ \$ 244 \$ 5,342 \$ 62,940		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Rider Clifer - Standby Fee System Control Charge (Rider SBC) Rider Clifer - Standby Fee System Control Charge (Rider SBC) Rider Revovery Charge (Rider SBC) Rider Revovery Charge (Rider SBC) Standby Service Charges DR*BD SR* SR* Customer Charges Distribution Energy Charges Riders Standby Charges Riders Standby Charges Total Charges</mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,182 \$ 3,6531 \$ 364 \$ 133,363 \$ 301 \$ 25,560 \$ 43,020 \$ 43,020 \$ 47,800 \$ 125,560 \$ 10,263 \$ 27,643 \$ 10,263 \$ 27,643 \$ 27,643 \$ 125,560 \$ 10,263 \$ 27,643 \$ 27,643 \$ 125,560 \$ 10,263 \$ 27,643 \$ 27,643 \$ 27,643 \$ 27,643 \$ 26,554 \$ 10,263 \$ 27,643 \$ 27,643 \$ 26,554 \$ 27,643 \$ 26,554 \$ 27,643 \$ 26,554 \$ 27,643 \$ 27,643 \$ 26,554 \$ 27,643 \$ 26,554 \$ 27,643 \$ 27,643 \$ 26,554 \$ 26,554 \$ 27,643 \$ 27,643 \$ 26,554 \$ 27,643 \$ 27,643 \$ 27,643 \$ 26,554 \$ 27,643 \$ 26,554 \$ 27,643 \$ 27,643 \$ 27,643 \$ 26,554 \$ 27,643 \$ 26,554 \$ 27,643 \$ 27,643	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 56,040 \$ 21,780 \$ 24,205 \$ 24,205 \$ 21,780 \$ 24,205 \$ 2,495 \$ 3,604 \$ 2,1780 \$ 2,425 \$ 2,245 \$ 3,604 \$ 2,7782 \$ 2,245 \$ 2,245 \$ 3,604 \$ 2,1780 \$ 2,425 \$ 2,785 \$ 2,245 \$ 2,245 \$ 2,245 \$ 3,011 \$ 2,625 \$ 2,785 \$ 2,245 \$ 2,785 \$ 2,785 \$ 2,245 \$ 2,785 \$ 2,495 \$ 2,495 \$ 2,495 \$ 2,495 \$ 2,780 \$ 2,425 \$ 2,785 \$ 2,245 \$ 2,785 \$ 2,245 \$ 2,785 \$ 2,245 \$ 2,785 \$ 2,785 \$ 2,785 \$ 2,785 \$ 2,785 \$ 2,785 \$ 2,785 \$ 3,785 \$ 3,113,166 \$ 3,115 \$ 3,1	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 6,853 \$ 2,495 \$ 16,531 \$ 301 \$ 21,780 \$ 24,200 \$ 62,940 High Tension Transmission \$ \$ 24,200 \$ 22,940 High Tension Transmission \$ \$ 24,200 \$ 22,940		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SEC) Rider CLEP - Standby Fee System Control Charge (Rider SEC) RGGI Revovery Charge (Rider SEC) Standby Service Charges DR*BD SR*<mm ag)<="" or="" td=""> SR*<cm< td=""> Customer Charges Distribution Energy Charges Distribution Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Fotal Charges Standby Charges Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders <tr< td=""><td>12,000 18,000 20,000 18,000 20,000 20,000 \$ 59 - \$ 10,263 \$ 10,263 \$ 7,132 \$ \$ 10,263 \$ 7,132 \$ \$ 16,551 \$ 364 \$ \$ 16,551 \$ 364 \$ \$ 43,020 \$ 47,800 \$ \$ 102,550 \$ \$ \$ \$ 10,25,580 \$ \$ \$ \$ 102,550 \$ \$ \$ \$ 102,550 \$ \$ \$ \$ 105,544 \$ \$ \$ \$ 105,560 \$ \$ \$ \$ 105,560 \$ \$ \$ \$ 105,560 \$ \$ \$</td><td>12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 335 \$ 301 \$ 56,040 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 77,820 Transmission \$ 24,200 \$ 77,820 \$ 24,200 \$ 77,820 \$ 24,200 \$ 77,820 \$ 77,820 \$ 24,200 \$ 77,820 \$ 24,200 \$ 77,820 \$ 77,820 \$ 24,200 \$ 77,820 \$ 77,820 \$ 77,820 \$ 77,820 \$ 26,821 \$ 77,820 \$ 77,820 \$</td><td>12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 244 \$ - \$ 244 \$ - \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 41,160 \$ 24,200 \$ 24,200 \$ 24,200 \$ 5,342 \$ 5,342 \$ 95,204 \$ 95,204</td></tr<></mm></cm<></mm></mm>	12,000 18,000 20,000 18,000 20,000 20,000 \$ 59 - \$ 10,263 \$ 10,263 \$ 7,132 \$ \$ 10,263 \$ 7,132 \$ \$ 16,551 \$ 364 \$ \$ 16,551 \$ 364 \$ \$ 43,020 \$ 47,800 \$ \$ 102,550 \$ \$ \$ \$ 10,25,580 \$ \$ \$ \$ 102,550 \$ \$ \$ \$ 102,550 \$ \$ \$ \$ 105,544 \$ \$ \$ \$ 105,560 \$ \$ \$ \$ 105,560 \$ \$ \$ \$ 105,560 \$ \$ \$	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 335 \$ 301 \$ 56,040 \$ 24,200 \$ 24,200 \$ 24,200 \$ 24,200 \$ 77,820 Transmission \$ 24,200 \$ 77,820 \$ 24,200 \$ 77,820 \$ 24,200 \$ 77,820 \$ 77,820 \$ 24,200 \$ 77,820 \$ 24,200 \$ 77,820 \$ 77,820 \$ 24,200 \$ 77,820 \$ 77,820 \$ 77,820 \$ 77,820 \$ 26,821 \$ 77,820 \$	12,000 13,000 20,000 High Tension Transmission \$ 244 \$ - \$ 244 \$ - \$ 244 \$ - \$ 244 \$ - \$ 2,495 \$ 16,531 \$ 364 \$ 133 \$ 301 \$ 41,160 \$ 24,200 \$ 24,200 \$ 24,200 \$ 5,342 \$ 5,342 \$ 95,204 \$ 95,204		
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) RiderE Non-Utility Generation Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider SBC) Rider CIEP - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD SR*CMM or AG) SR*CMM or AG) SR*CMM or AG) Standby Demand Charge (SDC=>[DR*BD)+(SR*<mm [sr*cd])<="" ag)]="" or="" td=""> Charges Incurred - Summary Customer Charges Distribution Energy Charges Riders Standby Charges Total Charges S/KWh (Delivered Energy) S/KWh (Delivered Energy)</mm></mm>	12,000 18,000 20,000 Primary \$ 59 \$ - \$ 10,263 \$ 7,132 \$ 3,162 \$ 16,531 \$ 364 \$ 336 \$ 34,020 \$ 47,800 \$ 125,580 Primary \$ 59 \$ 10,263 \$ 36,514 \$ 36,514 \$ 10,263 \$ 47,800 \$ 125,580 \$ 10,263 \$ 27,643 \$ 125,580 \$ 10,263 \$ 25,580 \$ 10,263 \$ 27,643 \$ 10,263 \$ 125,580 \$ 10,263 \$ 27,643 \$ 10,263 \$ 27,643 \$ 10,263 \$ 125,580 \$ 10,263 \$ 27,643 \$ 10,263 \$ 27,643 \$ 125,580 \$ 10,06744 \$ 0,00744 \$ 0	12,000 18,000 20,000 Transmission \$ 244 \$ - \$ 8,281 \$ 6,996 \$ 2,495 \$ 16,531 \$ 364 \$ 33 \$ 301 \$ 56,040 \$ 21,780 \$ 21,780 \$ 21,780 \$ 24,200 \$ 21,780 \$ 24,200 \$ 21,7820 Transmission \$ 244 \$ 36,21 \$ 77,820 Transmission \$ 244 \$ 0,96,821 \$ 77,820 Transmission \$ 244 \$ 0,96,821 \$ 0,066,89 \$ 0,06	12,000 18,000 20,000 High Tension Transmission \$ 244 \$ - \$ 5,342 \$ 6,853 \$ 2,495 \$ 16,531 \$ 2,495 \$ 364 \$ 21,780 \$ 24,200 \$ 62,940 High Tension Transmission \$ \$ 244 \$ 5,342 \$ 62,940 High Tension Transmission \$ \$ 26,677 \$ 62,940 \$ 95,204 \$ 0.03926 \$ 0.03926 \$ 0.03926		

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 86 of 118

Jersey Central Power & Light Company Standby Rates						
May through October	-		_	Volta	ge Le	evel
Rates as of October 1, 2012	Pri	mary	Tra	insmission	High	n Tension Transmission
Delivery Service Charges						
Customer Charge	\$	59.06	\$	243.81	\$	243.81
Distribution Charges			~			
KW Charge (DR)	\$	6.37	\$	4.67	\$	3.43
kwn Charge	181	0.004232	5	0.003415	\$	0.002203
Riders		0.000044	÷	0.000005	~	0.000000
Non-Utility Generation Charge (Hider NGC) (\$/KWH)	3	0.002941	9 6	0.002885	\$	0.002826
Contractional Energy Facility Assessment Charge (nider TEFA) (\$/KWII)		0.001312	₽ €	0.001029	\$	0.001029
Dider CIER - Standby Eco (\$/kWh)		0.000017	ф ф	0.000817	ф ¢	0.000817
System Control Charge (Pider SCC) (\$/kWb)	le l	0.000150	9	0.000150	¢ ¢	0.000150
PGGL Povovoni Charge (Pider SCC) (\$/kWith)	0	0.0000000	ф ф	0.000055	ф ф	0.000055
nodi nevovely charge (nider nno) (økwin)	1.	0.000124	φ	0.000124	φ	0.000124
Standby Service Charges						
Demand Bate (DB)	\$	6.37	\$	4.67	¢	3.43
Standby Bate (SB)	ŝ	2.39	ŝ	1.21	ŝ	1.21
	Ť				÷	The L
Billable Units	Pri	mary	Tra	Insmission	High	n Tension Transmission
Delivery Service Charges						
Customer Charge		1		1		1
Distribution Charges						
kW Charge		-		-		-
kWh Charge	2	2,425,000		2,425,000		2,425,000
Riders						*
Non-Utility Generation Charge (Rider NGC)	2	2,425,000		2,425,000		2,425,000
Transitional Energy Facility Assessment Charge (Rider TEFA)	2	2,425,000		2,425,000		2,425,000
Societal Benefits Charge (Rider SBC)	2	2,425,000		2,425,000		2,425,000
Rider CIEP - Standby Fee	2	2,425,000		2,425,000		2,425,000
System Control Charge (Rider SCC)	2	2,425,000		2,425,000		2,425,000
RGGI Revovery Charge (Rider RRC)	2	2,425,000		2,425,000		2,425,000
Standby Service Charges						
Standby Service Charges Billing Demand (BD)		12,000		12,000		12,000
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""><td></td><td>12,000 18,000</td><td></td><td>12,000 18,000</td><td></td><td>12,000 18,000</td></mm>		12,000 18,000		12,000 18,000		12,000 18,000
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>		12,000 18,000 20,000		12,000 18,000 20,000		12,000 18,000 20,000
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD)</mm>	Driv	12,000 18,000 20,000	Tra	12,000 18,000 20,000	Ulai	12,000 18,000 20,000
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges</mm>	Pri	12,000 18,000 20,000 mary	Tra	12,000 18,000 20,000	Higl	12,000 18,000 20,000 1 Tension Transmission
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges</mm>	Pri	12,000 18,000 20,000 mary	Tra	12,000 18,000 20,000	Higi	12,000 18,000 20,000
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" -="" ag)="" charge="" charges="" contract="" customer="" delivery="" demand="" detail="" detail<="" details="" incurred="" or="" service="" td=""><td>Prii \$</td><td>12,000 18,000 20,000 mary 59</td><td>Tra \$</td><td>12,000 18,000 20,000 ansmission 244</td><td>Higi \$</td><td>12,000 18,000 20,000 1 Tension Transmission 244</td></mm>	Prii \$	12,000 18,000 20,000 mary 59	Tra \$	12,000 18,000 20,000 ansmission 244	Higi \$	12,000 18,000 20,000 1 Tension Transmission 244
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges W/ Charge</mm>	Prii \$	12,000 18,000 20,000 mary 59	Tra \$	12,000 18,000 20,000 Insmission 244	Higi \$	12,000 18,000 20,000 n Tension Transmission 244
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge Why Charge</mm>	Prin \$ \$ \$	12,000 18,000 20,000 mary 59	Tra \$ \$	12,000 18,000 20,000 Insmission 244	Higi \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,242
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KWC Charge</mm>	Prii \$ \$ \$	12,000 18,000 20,000 mary 59 - 10,263	Tra \$ \$ \$	12,000 18,000 20,000 Insmission 244 - 8,281	Higi \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342
Standov Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" -="" ag)="" charge="" charges="" contract="" customer="" deliverv="" demand="" detail="" hiders="" incurred="" k<="" ki="" kiders="" kw="" or="" riders="" service="" td="" usithuition=""><td>Prin \$ \$ \$</td><td>12,000 18,000 20,000 mary 59 - 10,263 7,132</td><td>Tra \$ \$</td><td>12,000 18,000 20,000 Insmission 244 8,281</td><td>Higi \$ \$ \$</td><td>12,000 18,000 20,000 1 Tension Transmission 244 5,342 6 952</td></mm>	Prin \$ \$ \$	12,000 18,000 20,000 mary 59 - 10,263 7,132	Tra \$ \$	12,000 18,000 20,000 Insmission 244 8,281	Higi \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6 952
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" (rider="" -="" ag)="" assessment="" charge="" charges="" contract="" customer="" delivery="" demand="" detail="" distribution="" earlity="" energy="" generation="" incurred="" kw="" ngc)="" non-utility="" or="" riders="" service="" td="" teea)<="" transitional=""><td>Pri:</td><td>12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182</td><td>Tra \$ \$ \$</td><td>12,000 18,000 20,000 ansmission 244 8,281 6,996 2,495</td><td>Higi \$ \$ \$ \$</td><td>12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2495</td></mm>	Pri:	12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182	Tra \$ \$ \$	12,000 18,000 20,000 ansmission 244 8,281 6,996 2,495	Higi \$ \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2495
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" (rider="" -="" ag)="" assessment="" benefits="" charge="" charges="" contract="" customer="" delivery="" demand="" detail="" energy="" facility="" generation="" incurred="" kw="" ngc)="" non-utility="" or="" riders="" service="" societal="" spc)<="" td="" tefa)="" transitional="" usitotion=""><td>Prii \$ \$ \$ \$</td><td>12,000 18,000 20,000 mary 59 10,263 7,132 3,182 16,531</td><td>Tra \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 unsmission 244 6,986 2,495 16,531</td><td>Higi \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,631</td></mm>	Prii \$ \$ \$ \$	12,000 18,000 20,000 mary 59 10,263 7,132 3,182 16,531	Tra \$ \$ \$ \$ \$	12,000 18,000 20,000 unsmission 244 6,986 2,495 16,531	Higi \$ \$ \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,631
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges WW Charge KWP Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SBC) Bidra (CIEP - Standby Eae</mm>	Prii \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 mary 59 10,263 7,132 3,182 16,531 364	Tra \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 	Higi \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" (rider="" -="" ag)="" assessment="" benefits="" charge="" charges="" clep="" contol="" contract="" customer="" delivery="" demand="" detail="" distribution="" energy="" facility="" fee="" generation="" incurred="" kw="" ngc)="" non-utility="" or="" rider="" riders="" sbc)="" scc)<="" service="" societal="" standby="" system="" td="" tefa)="" transitional=""><td>Prii \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182 16,531 364 133</td><td>Tra \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 Insmission 244 6,996 2,495 16,531 364 133</td><td>Higi \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133</td></mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182 16,531 364 133	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 Insmission 244 6,996 2,495 16,531 364 133	Higi \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges KW Charge KW Charge Hiders Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Control Charge (Rider SCC) RiGdi Revorey Charge (Rider RBC)</mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 59 10,263 7,132 3,182 16,531 364 133 301	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 nnsmission 244 8,281 6,996 2,495 16,531 364 133 301	Higi \$ \$\$ \$\$\$	12,000 18,000 20,000 n Tension Transmission 244 5,342 6,853 2,495 16,531 364 13,34 301
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<="" or="" td=""> Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Sustinon Charge KW Charge Riders Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Banefits Charge (Rider SBC) Rider CIEP - Standy Fee System Control Charge (Rider SCC) RGGI Revovery Charge (Rider RRC)</mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 59 - 10,263 7,132 3,182 16,531 364 133 301	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 ansmission 244 8,281 6,996 2,495 16,531 364 133 301	Higi \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133 301
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" (rider="" -="" ag)="" assessment="" benefits="" charge="" charges="" charges<="" ciep="" contract="" control="" customer="" delivery="" demand="" detail="" energy="" facility="" fee="" generation="" incurred="" kwh="" ngc)="" non-utility="" or="" revovery="" rggi="" rider="" riders="" rrc)="" sbc)="" scc)="" service="" societal="" standby="" system="" td="" tefa)="" transitional="" ustribution=""><td>Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182 16,531 364 133 301</td><td>Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 </td><td>Higi ន ទទ ទទទ</td><td>12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133 301</td></mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182 16,531 364 133 301	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 	Higi ន ទទ ទទទ	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133 301
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm ag)<br="" or="">Contract Demand (CD) Charges Incurred - Detail Delivery Service Charges Customer Charge Distribution Charges WC harge Hidars Non-Utility Generation Charge (Rider NGC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Transitional Energy Facility Assessment Charge (Rider TEFA) Societal Benefits Charge (Rider SCC) Rider CIEP - Standby Fee System Control Charge (Rider RRC) Standby Service Charges DR*BD</mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 mary 59 - 10,263 7,132 3,182 16,531 364 133 301 76,440	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 insmission 244 - 8,281 6,996 2,495 16,531 364 133 301 56,040	Higi ន ទទ ទទទទ	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133 301 41,160
Standby Service Charges Billing Demand (BD) Minimum of Max Monthly demand or Average Generation (<mm (cd)="" (rider="" -="" ag)="" ag)<="" assessment="" benefits="" biders="" charge="" charges="" clep="" contract="" control="" customer="" delivery="" demand="" detail="" distribution="" dr*bd="" energy="" facility="" fee="" generation="" incurred="" kw="" ngc)="" non-utility="" or="" revovery="" rggi="" rider="" rrc)="" sbc)="" scc)="" service="" societal="" sr*<mm="" standby="" system="" td="" tefa)="" transitional=""><td>Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 mary 59 10,263 7,132 3,182 16,531 364 133 301 76,440 43,020</td><td>Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 20,000 244 - 8,281 6,996 2,495 16,531 364 133 301 56,040 21,780</td><td>Higi \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$</td><td>12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133 301 41,160 21,780</td></mm>	Prii \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 mary 59 10,263 7,132 3,182 16,531 364 133 301 76,440 43,020	Tra \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 20,000 244 - 8,281 6,996 2,495 16,531 364 133 301 56,040 21,780	Higi \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	12,000 18,000 20,000 1 Tension Transmission 244 5,342 6,853 2,495 16,531 364 133 301 41,160 21,780
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Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 87 of 118



Note: Standby Demand Charges are equal when generator availability is greater than 50%.

JCP&L Standby Demand Charge Compared with Charge Associated with Suggested Revision

Attachment Ohio-1 Page 1 of 4

Description of Model Standby Rates – Ohio Power Company

Brubaker and Associates, Inc. created a model that estimates the monthly charges incurred by an Ohio Power Company customer with on-site generation under both Schedule Standard Standby Service (SBS) and Schedule Open Access Distribution Standby Service (OAD-SBS) for both the Columbus Southern Power Rate Zone and the Ohio Power Rate Zone. The model analyzed three rate classes: (1) General Service – Medium Load Factor (Schedule GS-3) at Secondary voltage, (2) Schedule GS-3 at Primary voltage and (3) General Service – Large (Schedule GS-4) at Transmission level voltage.

The terms and conditions for provision of distribution service are the same for both Schedule SBS and Schedule OAD-SBS. The model also accounts for supplemental power, provided under the applicable full requirements tariff, as well as several riders that must be applied to each scenario.

The model requires the user to input 9 fields, either manually or from a drop down list, described below:

- 1. Rate class (choice of either GS-3 at Secondary or Primary, or GS-4 at Transmission);
- 2. Customer's peak demand;
- 3. Customer's load factor;
- 4. Net capability of the on-site generator;
- 5. Generator load factor;
- 6. Customer's selection of level of forced outage from the tariff (choice of either 5, 10, 15, 20, 25, or 30 percent);
- 7. Planned forced outage factor used in the model as representative of generator's actual operation;
- 8. Period of forced outage (choice of either monthly, seasonal or annual); and
- 9. Time of forced outage use (choice of either on-peak, off-peak, or around-the-clock (ATC)).

Based on the user-provided inputs, the model determines charges in four categories: Backup, Maintenance, Forced Outage, and Supplemental. Schedule SBS is priced under 2012 rates approved for Ohio Power Company and Schedule OAD-SBS is priced under a combination of the current approved distribution tariff and an assumed matrix of 2011 market prices at the AEP pricing hub.

Backup charges are associated with the power and energy that Ohio Power Company must have available in case of an unplanned forced outage. The charges incurred in this category consist of the customer charge on the Standby Service Rider, the monthly backup demand charge based on the demand of the on-site generator, its forced outage rate, and other applicable riders.

Maintenance charges are associated with the power and energy that the utility provides for the duration of a planned outage. The customer must notify Ohio Power Company at least six months in advance of the planned maintenance and may only perform such maintenance during periods of the year specified in the tariff. Maintenance charges are for the amount of energy that is normally produced by the generator. For Standard Standby Service customers, rates reflect the 2012 approved tariff. Under Schedule OAD-SBS, the model assumes that maintenance

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 89 of 118

Attachment Ohio-1 Page 2 of 4

energy costs are priced at the 2011 off-peak average of wholesale market prices at the AEP hub for Open Access Distribution Service. Applicable riders are also included.

Forced outage charges are associated with the power and energy that Ohio Power Company must provide for the duration of an unplanned outage. These charges are higher than for maintenance because of the unexpected nature of an unplanned outage. The charges for forced outages are for the energy that is normally produced by the generator, plus applicable riders. For Open Access Distribution Service customers, the energy rates in this category are related directly to the 2011 market prices at the AEP pricing hub and the user defined pricing period and hours. For Standard Standby Service customers, rates reflect the 2012 approved tariff.

Supplemental charges cover the costs of electricity needed to fulfill the remainder of the customer load -- the load less the on-site generation. For customers taking energy service from the utility, rates for these charges are in Schedules GS-3 and GS-4. The energy costs for Open Access Distribution Service customers are based on an around the clock average of 2011 AEP wholesale market prices. Costs in this area are for supplemental demand, supplemental energy and applicable riders.

The model summarizes all of the charges for both the Standard Standby Service customer and the Open Access Distribution Service customer in a tab labeled Summary. The totals for each category are shown along with the totals for each type of charge: demand, energy, customer, and riders. The final cost at the bottom of the summary sheet is the total of all charges for energy both purchased and generated on site, divided by the customer's entire load for the month.

Instructions for Using the Model

- 1. On the inputs tab, fill in all of the blue boxes. The rate class and the six forced outage options must be chosen from a drop down menu.
- 2. Make sure the file calculates. Press F9 if necessary.
- 3. If the user is satisfied with the inputs, click the Generate Plot Data button. This button generates graphs to allow the user to compare all of the scenarios side by side in graphical form. These graphs can be found on the Plots tab and will be explained in greater detail below.
- 4. Now the user can go to the Summary tab and view a summary sheet of both Standard Standby Service and Open Access Distribution Service. Note: Steps 3 is optional. The summary sheet will generate values once the user inputs have been completed.

Definition of Inputs

- **Rate Class** This is the rate class and voltage level of the customer. The choices in the drop down menu are primary, secondary, and sub-transmission/transmission.
- **Peak Demand** The maximum demand in kilowatts that is required to fulfill the customer's entire load.
- Load Factor The ratio of average demand to peak demand over a period of time. For this model, that period of time is 730 hours. Load factor can be calculated as the average monthly energy consumption divided by the peak demand times 730 hours.
- **Owned Generation Load Factor** The ratio of average generation to maximum generation of the on-site generator.
- Generator Capacity The net capacity in kilowatts (kw) of the customer's generator.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 90 of 118

Attachment Ohio-1 Page 3 of 4

- Forced Outage Factor The percentage of hours in a month that a generator can be expected to be unavailable due to an unexpected outage. The available options are 5, 10, 15, 20, 25, and 30 percent, which correlate to the Service Reliability Levels found in the tariffs.
- Planned Outage Factor The percentage of hours in a month that a generator can be expected to be unavailable due to a planned maintenance outage. Note that an input of 10 equals 10 percent.
- Forced Outage Period Three options are given for this input field: Annual, Monthly, and Seasonal. This input allows the user to choose how the energy purchased during a forced outage will be priced. If the user chooses Annual, the energy purchased during the forced outage will be based on the 2011 average price at the AEP pricing Hub. If the user chooses Monthly, the model will choose a random month in 2011 and price accordingly. If the user chooses Seasonal, the model will choose a random season: Winter, Spring, Summer, or Fall, which are averages of three months. This option only affects the forced outage energy prices for the Open Access Distribution Service customer.
- Forced Outage Hours Three options are given for this input field: On-Peak, Off-Peak, and ATC, which means around-the-clock. This input allows the user to choose which time of day in the forced outage period will be used for forced outage energy prices. For example, if the user selects Seasonal in the Forced Outage Period and Off-Peak in the Forced Outage Hours, then for the duration of the forced outage, the energy purchased will be priced at the Off-Peak average of wholesale market prices during the random season selected by the model. This option only affects the Forced Outage energy prices for the Open Access Distribution Service customer.

Plots Tab

The plots tab consists of four bar graphs that allow the user to compare the total cost in c/kWh for all of the scenarios for the user-defined rate class and load and generator characteristics. The plots on this page are generated when the Generate Plots Data button is pressed on the inputs tab. Note that there is no variation in the six forced outage rates. In other words, all of these plots are generated with the assumption that the Allow Variable Forced Outage Duration option is set to FALSE on the Input tab.

- SBS Rate by Forced Outage Rate This bar graph displays the per-unit cost of electricity under Standard Standby Service with various forced outage rates. The x-axis is the forced outage rate and the y-axis is the overall cost of electricity in ¢/kWh.
- OAD Rate Monthly FOR Detail This bar graph displays the per unit cost of electricity under Open Access Distribution Service for each month of the year, each forced outage rate, and each of the forced outage hours options. This graph can only display information for one forced outage rate at one time. In order to change the forced outage rate shown in the graph, click anywhere on the whitespace on the graph. This will bring up the Pivot Chart Filter Pane. Using the Report Filter field, select the forced outage rate that is desired. The x-axis shows the months of the year and the y-axis the cost of electricity in ¢/kWh. The ATC, On-Peak, and Off-Peak designations do not refer to rates seen by the customer during those months and timeslots of the year. Instead, these timeslots refer to the period in which the forced outage energy was priced. For example, the green On-Peak bar for August represents the overall cost in ¢/kWh for standby service with a forced outage charged at an energy rate equal to the average On-Peak price during August 2011 at the AEP pricing hub.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 91 of 118

> Attachment Ohio-1 Page 4 of 4

- OAD Rate Seasonal Forced Outage Rate Detail This bar graph is similar to the Monthly graph with the only difference between the two being the x-axis definition. The seasonal graph displays each season as opposed to each month.
- OAD Rate Annual Forced Outage Rate Detail This graph is similar to the other OAD graphs, but the pricing period for the forced outage energy has been averaged for the entirety of 2011. The x-axis on this graph represents the forced outage rate.

Other Tabs

- Summary Study parameters are input in this tab.
- **Inputs** Inputs for the case or scenario to be studied.
- Detail (SBS) Calculates the cost for Standard Backup Service rate.
- Detail (OBS) Calculates the cost for Open Access Backup Service.
- Rates and Riders Contains utility rates or changes in riders.
- Schedule GS-3, GS-4 and OAD Contains utility's full-service rates.
- **Outages** Summary of market prices needed to develop open access energy charges.
- Market Prices Market prices for energy for open access scenario.
- Plot Data Contains data for graphs in the Plots tab.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 92 of 118

Load Characte	ristics	
Demand	1,500	kW
Load Factor	70.00	%
Cogen Load Factor	100.00	%
Supplemental Load Factor	43.75	%
Supplemental Load	800	kW
Self Generation Capability	700	kW
Monthly Energy	766,500	kWh
Forced Outage Hours	146	Hours
Maintenance Outage Hours	73	Hours

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 93 of 118

Ohio Power Co	mpany - Columbus S	outhern			Ohio Power	Company - Columb	us South	ern
	Schedule SBS					Schedule SBS-OAD		
	Rate Class: Primary					Rate Class: Primary		
	Units		Cost		Ctandbu	Units		Cost
(V) (H)	700 357,700	64 64 6 6	4,448		Demand (kW) Energy (kWh)	700 357,700	6 6 6	2,228
	~	n 10 10	1,995 - 6,443		Kiders Customer Subtotal	F	w w w	1,448 - 3,676
unce (VV) Vh)	51,100 1	69 69 69 69 69 69 69 69 69 69 69 69 69 69 69 69 69 6	- 405 2,625 -		Maintenance Demand (kW) Energy (kWh) Riders Customer	51,100 1	0 0 0 0 0 0 0	1,672 332
(h)		9	5.9293	50	ouptotai Cost (¢/kWh)		9	2,004 3.9224
iental kW) Wh) Wh)	800 255,500 1	မ မ မ မ မ	10,276 18 16,204 115 26,614		Supplemental Demand (kW) Energy (kWh) Riders Customer Subtomer Subtomer	800 255,500 1	0 0 0 0 0 0 0	5,469 9,973 9,973 2,176 115 17,733 6 9405
(MV) (dAV (dA V	102,200	69 69 69 69	5,063 5,063 5,063 4.9541		Backup Demand (kW) Erergy (kWh) Rider Subtotal Subtotal Cost (¢/KWh)	102,200 1	မ မ မ မ မ	3,989 664 664 4,653
łł	766,500 1,500	က က က က	424 14,724 115 25,887 41,150 5.3686		Totals Energy Demand Customer Silder Sibiotal Cost (¢/KWh)	766,500 1,500	မ မ မ မ	15,634 7,697 115 4,620 28,067 3.6617

1,672 332 2,004 **3.9224**

Cost 2,228 1,448 3,676

5,469 9,973 2,176 115 117,733 6.9405

3,989 664 4,653 **4,5530**

15,634 7,697 115 4,620 28,067 3.6617

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 94 of 118

Load Charact	eristics	
Demand	6,000	kW
Load Factor	80.00	%
Cogen Load Factor	100.00	%
Supplemental Load Factor	40.00	%
Supplemental Load	2,000	kW
Self Generation Capability	4,000	kW
Monthly Energy	3,504,000	kWh
Forced Outage Hours	73	Hours
Maintenance Outage Hours	73	Hours

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 95 of 118

Ohio Power Com	pany - Columbus So	uthern	Ohio Power	Company - Columbus S	southern
- U)	Schedule SBS			Schedule SBS-OAD	
Rate	e Class: Primary			Rate Class: Primary	
Standbu	Units	Cost	Ctandhu	Units	Cost
Demand (kWh) Energy (kWh) Riders	4,000 2,336,000	\$ 19,696 \$ - \$ 4,027	Demand (kW) Energy (kWh) Riders	4,000 2,336,000	\$ 12,732 \$ - \$ 2,413
Customer Subtotal	-	\$ - \$ 23,723	Customer Subtotal	~	\$ - \$ 15,145
Maintenance Demand (kW) Energy (kWn) Riders Subtoral Subtoral Cost (¢/kWn)	- 292,000	\$ 2,316 \$ 2,316 \$ 14,214 \$ 16,530 5.6608	Maintenance Demand (kW) Energy (kWh) Riders Customer Subtotal Cost (¢/kWh)	292,000 1	\$ 9,556 \$ 1,113 \$ 10,669 3.6533
Supplemental Demand (kW) Energy (kWh) Riders Customer Customer Customer Custotal Custotal	2,000 564,000	\$ 25,690 \$ 42 \$ 37,588 \$ 115 \$ 63,435 10.8622	Supplemental Demand (kW) Energy (kWh) Riders Customer Subtotal Cost (g/KWh)	2,000 584,000	\$ 13,672 \$ 22,795 \$ 5,035 \$ 115 \$ 41,616 7.1261
Backup Demand (kWh) Energy (kWh) Riders Riders Subtola Cost (¢/kWh)	- 292,000 1	\$	Backup Demand (kVV) Energy (kVVh) Ridens Ridens Subtotal Customer Customer	- 292,000 1	\$ 11.397 \$ 1.782 \$ 1.782 \$ 13.179 4.5134
Totals Demergy Demand Customer Subtotal Subtotal Cost (g/kWh)	3,504,000 6,000	\$ 2,358 \$ 45,386 \$ 115 \$ 70,179 \$ 118,038 3.3687	Totals Energy Demand Customer Rider Subtotal Cost (¢/KWh)	3,504,000 6,000	\$ 43,748 \$ 26,404 \$ 115 \$ 10,343 \$ 0,610 2.3005

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 96 of 118

Load Charac	teristics	
Demand	30,000	kW
Load Factor	75.00	%
Cogen Load Factor	100.00	%
Supplemental Load Factor	25.00	%
Supplemental Load	10,000	kW
Self Generation Capability	20,000	kW
Monthly Energy	16,425,000	kWh
Forced Outage Hours	36.5	Hours
Maintenance Outage Hours	36.5	Hours

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 97 of 118

Ohio Power (Company - Columbus	Southe	L.
	Schedule SBS-OAD		
Rate Class	:: Subtransmission/Transm	lission	
	Units		ပိ
Demand (kW)	20,000	69	
Energy (kWh)	13, 140,000	ŝ	'
Riders	Ŧ	un u	• •
Subtotal	-	с о	'
Maintenance			
Demand (kW)	ı	65	
Energy (kWh)	730,000	6.00	23.89
Riders		Ф	2,78
Customer	-	ŝ	. 1
Subtotal		÷	26,67
Cost (¢/kWh)			3.653
Supplemental			
Demand (kW)	10,000	69	10.959
Energy (kWh)	1,825,000	ю	71,23
Riders		в	9,40
Customer	£	ф	1,06
Subtotal		ю	92,661
Cost (¢/kWh)			5.077
Backup			
Demand (kW)		69	'
Energy (kWh)	730 000		28.49
Riders		÷ €3	2.78
Customer	÷	69	. '
Subtotal		6.9	31.27
Cost (¢/kWh)			4.284
I otals			
Energy	16,425,000	<i>с</i> э (123,61
Demand	30,000	69 6	10,95
Rider	-	0 U	14 07
Subtotal		÷ 65	150.61
Cost (¢/kWh)		•	0.917

Ohio Power Company	- Columbus So	uthern
Sched Rate Class: Subtrans	ile SBS nission/Transmissi	5
Standby	UNITS	COST
Demand (kW)	20,000	\$ 17,440
Energy (kWh)	13,140,000	69 -
Riders		\$ 3,995
Customer Subtotal	ſ	\$ 21.435
Maintenance		
Demand (kW)		
Energy (kwn)	/30,000	5 1,886
Cilistomer	*	n _ 't` + +
Subtotal	-	\$ 36.065
Cost (¢/kWh)		4.9404
Supplemental		
Demand (kW)	10.000	\$ 59.735
Energy (kWh)	1,825,000	. ' Ф
Riders		\$ 115,782
Customer	-	\$ 1,060
Subtotal		\$ 176,577
Cost (¢/kWh)		9.6754
Backup		
Demand (kW)		י ھ
Energy (kWh)	730,000	Ф
Riders		\$ 33,581
Customer	-	5
Subtotal		\$ 33,581
		- 000°±
Totals		
Energy	16,425,000	\$ 1,886
Demand	30,000	\$ 77,175 \$ 1050
Rider	_	\$ 187.536
Subtotal		\$ 267,657
Cost (¢/kWh)		1.6296

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 98 of 118

Load Characte	ristics	
Demand	1,500	kW
Load Factor	70.00	%
Cogen Load Factor	100.00	%
Supplemental Load Factor	43.75	%
Supplemental Load	800	kW
Self Generation Capability	700	kW
Monthly Energy	766,500	kWh
Forced Outage Hours	146	Hours
Maintenance Outage Hours	73	Hours

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 99 of 118

		ower
S	chedule SBS-OAD	
R	te Class: Primary	
Ctanalbu C	Units	
Demand (kWh) Energy (kWh)	700 357,700	တမ
Customer Subtotal	~	ကမဟ
Maintenance Demand (kW) Energy (kWh) Riders Customer Subtotal Cost (pkMh)	51,100	0 0 0 0 0 0 0
Supplemental Demand (KW) Energy (KWh) Riders Custonmer Subtotal Cost (¢KWh)	800 255,500 1	မ မ မ မ မ
Backup Demand (xw) Erengy (xWh) Riders Customer Subtotal Subtotal Subtotal	102,200	.
Totals Energy Customand Customer Rider Rider Cost (gkwth) Cost (gkwth)	766,500 1,500 1	မ လ မ မ မ
	Cost (#KWh) Totals Energy Energy Customer Rudor Rudor Subtoal Subtoal	Cost (s/kWh) Totals 766,500 Energy 1,500 Demand 1,500 Rider Rider Subtral Subtral Cost (s/kWh)

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 100 of 118

Load Charact	eristics	
Demand	6,000	kW
Load Factor	80.00	%
Cogen Load Factor	100.00	%
Supplemental Load Factor	40.00	%
Supplemental Load	2,000	kW
Self Generation Capability	4,000	kW
Monthly Energy	3,504,000	kWh
Forced Outage Hours	73	Hours
Maintenance Outage Hours	73	Hours

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 101 of 118

Ohio Powe	er Company - Ohio Pov	ver	 Ohio Powe	er Company - Ohio P	ower	Γ
	Schedule SBS			Schedule SBS-OAD		Γ
	Rate Class: Primary			Rate Class: Primary		Π
	Units	Cost	Ctandbu	Units	0	Cost
(kW) «Wh)	4,000 2,336,000	\$ 18,040 \$ - \$ 6.704	Demand (kWh) Energy (kWh) Riders	4,000 2,336,000	କ କ ମୁନ୍ଦୁ ଅନ୍ତୁ	040 - 867
-s	÷	\$ 24,744	Customer Subtotal	۲	8 8 1 8 1 8 1 8	- 106
lance (kW) kWh)	- 292,000	\$ 2,664	Maintenance Demand (kW) Energy (kWh)	- 292,000	ы 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9 9	-
sr KWh)	E.	\$ 12,386 \$ 15,050 5.1541	Riders Customer Subtotal Cost (¢/kWh)		8 8 8 3.0,6	109 - 5524
mental (kW) kWh)	2,000 584,000	\$ 25,460 \$ 1,117	Supplemental Demand (kW) Energy (kWh)	2,000 584,000	\$ 14,8	826 795
sr kWh)	۴	\$ 33,308 \$ 95 \$ 60,041 10.2810	Riders Customer Subtotal Cost (¢/kWh)	~	\$ 43,7	95 95 215 3998
(kWh)	292,000	€ 898 1008 2008 2008 2008	Backup Demand (kW) Energy (kWh)	- 292,000	୍ୟ କ କ ମୁନ୍ଦୁ ସୁନ୍ଦୁ	397
ar kWh)	-	\$ 12,926 \$ 12,926 4.4266	Customer Subtotal Cost (¢/kWh)	~	\$ 13,0 4.4	- 066 1748
- 5	3,504,000 6,000	\$ 4,679 \$ 43,500 \$ 95	Totals Energy Demand Customer	3,504,000 6,000	୫୫୫ 29,5	748 866 95
(Wh)		\$ 64,485 \$ 112,760 3.2180	Rider Subtotal Cost (¢/kWh)		\$ 85,8	144 853 1501

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 102 of 118

Load Charac	teristics	
Demand	30,000	kW
Load Factor	75.00	%
Cogen Load Factor	100.00	%
Supplemental Load Factor	25.00	%
Supplemental Load	10,000	kW
Self Generation Capability	20,000	kW
Monthly Energy	16,425,000	kWh
Forced Outage Hours	36.5	Hours
Maintenance Outage Hours	36.5	Hours

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 103 of 118

ver	Ohio Power Col	npany - Ohio Pow
	Schedi	e SBS-OAD
	Rate Clas	: Transmission
	Cost	Units
လ လ လ လ ရ	6,400 Demand (kW) 6,620 Energy (kWh) 6,620 Ridens 3,220 Subtotal	20,000 13,140,000 1
လ လ လ လ ြမ	- Maintenance Maintenance 2.334 Energy (KWh) Energy (KWh) 9.291 Energy (KWh) 1.625 Costoner 3.344 A.344 Costoner 3.344 Costone	730,000
မ မ မ မရ	3 500 Supplemental Supplemental (\W) 866 Energy (\Wh) Energy (\Wh) 59.416 Ricers 61.2 Subolal 4655 Cost (struct	10,000 1,825,000 1
	2.334 Backup Energy (kWh) 8.160 Riters Riters Oustomer 0.554 Cost (kWh)	- 730,000 1
မ မ မ မ မ	5554 Totals 5554 Totals 7020 Demend 512 Customer 3,147 Subtoal 0.0113 Cost (RMMh)	16,425,000 30,000 1

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 104 of 118

Attachment Ohio - 3 Page 1 of 2

Small Load Economic Analysis Forced Outage 20% Self Gen. Backup Backup Maint. Maint. Maint. <u>kW</u> 700 <u>kWh</u> 102,200 <u>kWh</u> 51,100 Days Hours Days 7 73 4 Schedule SBS <u>\$/kWh</u> Modi d Schedule SBS <u>Standby</u> Generation Transmission Distribution Total <u>\$/kW</u> \$3.171 \$/kW \$0.483 Charges \$2,220 \$/kWh Charges \$338 \$0 \$1,782 \$2,120 \$0.500 \$3.183 \$0.000 \$2.546 \$350 \$2,228 \$4,798 Backup Generation Transmission Distribution \$/kW/Day \$0.30600 \$0.06680 \$0.02122 \$1,499 \$708 <u>\$104</u> \$2,312 \$0.00356 \$364 \$0.00373 \$364 Total <u>Maintenance</u> Generation Transmission Distribution \$0.00280 \$0.00417 \$0.00513 \$0.1530 \$0.0334 \$0.0106 \$428 \$189 <u>\$30</u> \$647 \$143 \$213 \$0.00186 \$262 \$618 Total TOTAL \$5,780 \$5,079 Medium Load Economic Analysis Self Gen. Forced Backup Backup Maint. Maint. Maint. <u>kW</u> 4,000 <u>kWh</u> 292,000 <u>kWh</u> 292,000 Outage Days Hours Days 10% 4 73 Mod SBS Schedule SBS d Schedu <u>Charges</u> \$6,964 \$1,000 <u>\$12,732</u> \$20,696 <u>Standby</u> Generation Transmission Distribution \$/kW \$1.741 \$0.250 \$3.183 \$0.483 \$0.000 \$2.546 <u>Charges</u> \$1,932 \$0 <u>\$10,184</u> \$12,116 \$/kWh \$/kWh Total Backup Generation Transmission Distribution \$/kW/Day \$0.30600 \$0.06680 \$4,896 \$2,158 <u>\$340</u> \$7,393 \$0.00356 \$1,040 \$0.00373 \$0.02122 Total \$1,040 Maintenance \$0.00280 \$0.00417 \$0.00513 \$0.1530 \$0.0334 \$0.0106 \$818 \$1,216 \$2,448 \$1,079 <u>\$170</u> \$3,697 Generation Transmission \$0.00186 Distribution \$1,498 \$3,532 Total TOTAL \$25,268 \$23,206

Columbus Southern Rate Zone Economic Analysis - Schedule SBS

		Large Load	Economic Ar	nalysis		
Self Gen. <u>kW</u> 20,000	Forced Outage 20%	Backup <u>kWh</u> 2,920,000	Backup <u>Days</u> 7	Maint. <u>kWh</u> 730,000	Maint. <u>Hours</u> 36.5	Maint. <u>Days</u> 2
		Schedule SBS	5	Modif	ed Schedul	e SBS
Standby Generation Transmission Distribution Total	<u>\$/kW</u> \$2.966 \$0.123 \$0.000	<u>\$/kWh</u>	Charges \$59,320 \$2,460 \$0 \$61,780	<u>\$/kW</u> \$0.483 \$0.000 \$0.000	<u>\$/kWh</u>	Charges \$9,660 \$0 <u>\$0</u> \$9,660
Backup Generation Transmission Distribution Total		\$0.00349	\$10,202 \$10,202	<u>\$/kW/Day</u> \$0.30600 \$0.08357 \$0.00000	\$0.00257	\$42,840 \$19,202 <u>\$0</u> \$62,042
<u>Maintenance</u> Generation Transmission Distribution Total		\$0.00258 \$0.00409 \$0.00000	\$7,544 \$11,932 <u>\$0</u> \$19,476	\$0.1530 \$0.0418 \$0.0000	\$0.0013	\$6,120 \$2,609 <u>\$0</u> \$8,729
TOTAL			\$91,459			\$80,432

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 105 of 118

Attachment Ohio - 3 Page 2 of 2

		Small Load	Economic Ar	nalysis		
Self Gen. <u>kW</u> 700	Forced Outage 20%	Backup <u>kWh</u> 102,200	Backup <u>Days</u> 7	Maint. <u>kWh</u> 51,100	Maint. Hours 73	Maint. <u>Days</u> 4
		Schedule SB	5	Modifi	ed Schedul	e SBS
Standby Generation Transmission Distribution	<u>\$/kW</u> \$1.820 \$1.310 \$3.760	<u>\$/kWh</u>	<u>Charges</u> \$1,274 \$917 <u>\$2,632</u> \$4,823	\$/kW \$0.449 \$0.000 \$3.008	<u>\$/kWh</u>	Charges \$314 \$0 \$2,106 \$2,420
Backup Generation Transmission Distribution Total		\$0.00307 \$0.00218	\$314 \$223 \$537	<u>\$/kW/Day</u> \$0.28400 \$0.07630 \$0.02510	\$0.00217	\$1,392 \$595 <u>\$123</u> \$2,110
Maintenance Generation Transmission Distribution Total		\$0.00280 \$0.00377 \$0.00513	\$143 \$193 <u>\$262</u> \$598	\$0.1420 \$0.0382 \$0.0126	\$0.00108	\$398 \$162 <u>\$35</u> \$595
TOTAL			\$5,958			\$5,125
		Medium Loa	d Economic /	nalveie		
Self Gen. <u>kW</u> 4,000	Forced Outage 10%	Backup <u>kWh</u> 292,000	Backup Days 4	Maint. <u>kWh</u> 292,000	Maint. Hours 73	Maint. <u>Days</u> 4
		Schedule SB	s	Modifi	ied Schedul	e SBS
<u>Standby</u> Generation Transmission Distribution Total	<u>\$/kW</u> \$0.750 \$0.660 \$3.760	<u>\$/kWh</u>	Charges \$3,000 \$2,640 <u>\$15,040</u> \$20,680	<u>\$/kW</u> \$0.449 \$0.000 \$3.008	<u>\$/kWh</u>	Charges \$1,796 \$0 \$12,032 \$13,828
Backup Generation Transmission Distribution Total		\$0.00307 \$0.00218	\$898 \$637 \$1,535	<u>\$/kW/Day</u> \$0.28400 \$0.07630 \$0.02510	\$0.00217	\$4,544 \$1,853 <u>\$402</u> \$6,799
Maintenance Generation Transmission Distribution Total		\$0.00280 \$0.00377 \$0.00513	\$818 \$1,101 <u>\$1,498</u> \$3,417	\$0.1420 \$0.0382 \$0.0126	\$0.00108	\$2,272 \$927 <u>\$201</u> \$3,400
TOTAL			\$25,632			\$24,027
		Large Load	Economic Ar	nalysis		
Self Gen. <u>kW</u> 20,000	Forced Outage 5%	Backup <u>kWh</u> 730,000	Backup Days 2	Maint. <u>kWh</u> 730,000	Maint. <u>Hours</u> 36.5	Maint. <u>Days</u> 2
		Schedule SB	S	Modif	ed Schedul	e SBS
<u>Standby</u> Generation Transmission Distribution Total	<u>\$/kW</u> \$0.320 \$0.320 \$0.000	<u>\$/kWh</u>	Charges \$6,400 \$6,400 <u>\$0</u> \$12,800	<u>\$/kW</u> \$0.429 \$0.000 \$0.000	<u>\$/kWh</u>	Charges \$8,580 \$0 <u>\$0</u> \$8,580
Backup Generation Transmission Distribution Total		\$0.00328 \$0.00213	\$2,394 \$1,555 \$3,949	<u>\$/kW/Day</u> \$0.27100 \$0.07430 \$0.00000	\$0.00211	\$10,840 \$4,516 <u>\$0</u> \$15,356
Maintenance Generation Transmission Distribution Total		\$0.00258 \$0.00368 \$0.00000	\$1,886 \$2,686 <u>\$0</u> \$4,572	\$0.1355 \$0.0372 \$0.0000	\$0.0011	\$5,420 \$2,258 <u>\$0</u> \$7,678

\$21,321

TOTAL

\$31,613

Ohio Power Rate Zone Economic Analysis - Schedule SBS

Attachment Ohio-4 Page 1 of 2

Columbu	us Southerr	Rate Zone	Economic Ana	alysis - Sched	ule OAD-S	SBS
		Small Load	Economic An	alysis		
Self Gen. <u>kW</u> 700	Forced <u>Outage</u> 20%	Backup <u>kWh</u> 102,200	Backup <u>Days</u> 7	Maint. <u>kWh</u> 51,100	Maint. <u>Hours</u> 73	Maint. <u>Days</u> 4
	Sc	hedule OAD-	SBS	Modified	Schedule (DAD-SBS
Standby Distribution	<u>\$/kW</u> \$3.183	<u>\$/kWh</u>	<u>Charges</u> \$2,228	<u>\$/kW</u> \$2.546	<u>\$/kWh</u>	<u>Charges</u> \$1,782
Backup Distribution				<u>\$/kW/Day</u> \$0.02122		\$104
Maintenance				\$0.0212		\$59
Total			\$2,228			\$1,946
		Medium Loa	d Economic A	nalysis		
Self Gen. <u>kW</u> 4,000	Forced <u>Outage</u> 10%	Backup <u>kWh</u> 292,000	Backup <u>Days</u> 4	Maint. <u>kWh</u> 292,000	Maint. <u>Hours</u> 73	Maint. <u>Days</u> 4
	Sc	hedule OAD-	SBS	Modified	Schedule (DAD-SBS
Standby Distribution	<u>\$/kW</u> \$3.183	<u>\$/kWh</u>	Charges \$12,732	<u>\$/kW</u> \$2.546	<u>\$/kWh</u>	Charges \$10,184
Backup Distribution				<u>\$/kW/Day</u> \$0.02122		\$340
Maintenance				\$0.0212		<u>\$340</u>
TOTAL			\$12,732			\$10,863
		Large Load	Economic An	alysis		
Self Gen. <u>kW</u> 20,000	Forced <u>Outage</u> 5%	Backup <u>kWh</u> 730,000	Backup <u>Days</u> 2	Maint. <u>kWh</u> 730,000	Maint. <u>Hours</u> 36.5	Maint. <u>Days</u> 2
	Sc	hedule OAD-	SBS	Modified	Schedule (DAD-SBS
Standby Distribution	<u>\$/kW</u>	<u>\$/kWh</u>	<u>Charges</u>	<u>\$/kW</u>	<u>\$/kWh</u>	<u>Charges</u>
Backup						

Distribution

Maintenance Distribution

Attachment Ohio-4 Page 2 of 2

Ohio	o Power Rat	e Zone Econ	omic Analysi	s - Schedule (DAD-SBS	
		Small Load	Economic An	alysis		
Self Gen. <u>kW</u> 700	Forced <u>Outage</u> 20%	Backup <u>kWh</u> 102,200	Backup <u>Days</u> 7	Maint. <u>kWh</u> 51,100	Maint. <u>Hours</u> 73	Maint. <u>Days</u> 4
	Sc	hedule OAD-S	SBS	Modified	Schedule (DAD-SBS
Standby Distribution	<u>\$/kW</u> \$3.760	<u>\$/kWh</u>	<u>Charges</u> \$2,632	<u>\$/kW</u> \$3.008	<u>\$/kWh</u>	<u>Charges</u> \$2,106
Backup Distribution				\$/kW/Day \$0.0251		\$123
Maintenance				\$0.0251		\$70
Total			\$2,632			\$2,299
		Medium Loa	d Economic A	nalysis		
Self Gen. <u>kW</u> 4,000	Forced <u>Outage</u> 10%	Backup <u>kWh</u> 292,000	Backup <u>Days</u> 4	Maint. <u>kWh</u> 292,000	Maint. <u>Hours</u> 73	Maint. <u>Days</u> 4
	Sc	hedule OAD-S	SBS	Modified	Schedule (DAD-SBS
Standby Distribution	<u>\$/kW</u> \$3.760	<u>\$/kWh</u>	<u>Charges</u> \$15,040	<u>\$/kW</u> \$3.008	<u>\$/kWh</u>	<u>Charges</u> \$12,032
Backup Distribution				<u>\$/kW/Day</u> \$0.02507		\$401
Maintenance Distribution				\$0.0251		<u>\$401</u>
TOTAL			\$15,040			\$12,834
		Large Load	Economic An	alysis		
Self Gen. <u>kW</u> 20,000	Forced <u>Outage</u> 5%	Backup <u>kWh</u> 730,000	Backup <u>Days</u> 2	Maint. <u>kWh</u> 730,000	Maint. <u>Hours</u> 36.5	Maint. <u>Days</u> 2
	Sc	hedule OAD-S	SBS	Modified	Schedule (DAD-SBS
Standby Distribution	<u>\$/kW</u>	<u>\$/kWh</u>	<u>Charges</u>	<u>\$/kW</u>	<u>\$/kWh</u>	Charges
Backup						

Backup Distribution

Maintenance Distribution

Attachment Utah-1 Page 1 of 3

Rocky Mountain Power Back-Up Rate Model

A model was created that estimates the monthly charges incurred by a Rocky Mountain Power (RMP) customer utilizing on-site generation under Electric Service Schedule No. 31 Back-Up, Maintenance, and Supplementary Power with Primary and Transmission level voltages analyzed. Supplemental power in excess of on-site generation is served under applicable standard tariffs. The two supplemental power rate schedules analyzed in the model are: (1) Large General Service Schedule No. 8 at Primary Voltage, and (2) General Service Schedule No. 9 at Transmission Voltage. In addition, there are several riders that must be applied to each scenario.

The model requires the user to input eleven fields, either manually or from a drop down list:

- Season (choice of either May through September or October through April);
- Customer's peak demand;
- Customer's load factor;
- Net capability of the on-site generator;
- Load Factor of the on-site generator;
- Start day of the week of the forced outage;
- Start hour of the day of the forced outage;
- Forced outage duration;
- Start day of the week of the maintenance outage;
- Start hour of the day of the maintenance outage; and
- Maintenance outage duration.

Based on these user-provided inputs, the model determines the amount of energy and power to be charged in four separate categories: Standby, Maintenance, Back-up, and Supplemental.

The Standby charge is the charge associated with the capacity that RMP must have available in case of either a forced outage (unscheduled) or a maintenance outage (scheduled) of the on-site generator. In this model, charges incurred in this category consist of the monthly Customer charge, the monthly Facilities charge based on the demand of the on-site generator, and other applicable riders.

Maintenance charges are the charges associated with the capacity and energy that RMP must provide for the duration of a planned outage. The customer must notify RMP at least 18 months in advance of the planned maintenance, and may not exceed 30 days per year. The costs related to maintenance are based on the demand of the on-site generator, a daily on-peak Maintenance demand charge, a seasonal Maintenance energy charge, and all other applicable riders.

Back-up charges are the charges associated with demand and energy that RMP must provide during a forced or unplanned outage. Back-up demand charges for a forced outage are greater than those of the Maintenance charges because of the unexpected nature of an unplanned outage. The costs related to forced outages are based on the demand of the on-site generator, a daily on-peak Back-up demand charge, a seasonal energy charge that is applied to the lost generation output, and other applicable riders. Back-up energy is priced the same as Maintenance energy.
Attachment Utah-1 Page 2 of 3

Supplemental charges cover the costs of electricity needed to fulfill the remainder of the customer load, i.e., the load less the on-site generation. Rates for supplemental usage are found in general Rate Schedules 8 and 9 with costs for demand, energy, plus all applicable riders. Also note that the on peak and off peak energy charges have been aggregated into a single charge. This is due to the fact that without load and generation profiles, the proper allocation of energy cannot be achieved.

The model has two tabs for the two studied voltage levels (Schedule 8 – Primary and Schedule 9 – Transmission). On each tab, the charges for the four categories are shown in both detail and summarized. Each category has the charges broken into five rate components: customer, facilities, power, energy, and riders. These cost are then totaled, allowing for a per unit cost (kWh) to be calculated for each category. The bottom left of each class tab has the grand total of all charges.

Instructions for Using the Model

- 1. On the inputs tab, fill in all of the orange boxes.
- 2. Make sure the file calculates. Press F9 to calculate, if necessary.
- 3. Tabs Schedule 8 and Schedule 9 model will now have calculated the costs for the various categories.
- 4. To evaluate various scenarios, alternative charges or rates will have to be inserted in the applicable Rates and Riders tab (Input Tab) which is discussed below.

Definition of Inputs

- Season May through September or October through April.
- **Peak Demand** The maximum demand in kilowatts that is required to fulfill the customer's entire load.
- Load Factor The ratio of average demand to peak demand over a period of time. For this model, that period of time is 730 hours. Can be calculated as the average monthly energy for the season divided by the peak demand times 730 hours.
- Generator Net Capability The net capacity of the on-site generator in kilowatts. Generally, the nameplate capacity of the unit less any environmental adjustments.
- **Generator Load Factor** The ratio of average generation to net capability over a period of time. For this model, that period of time is 730 hours. Can be calculated as the average monthly energy for the season divided by the net capability times 730 hours.
- Forced Outage Start Day The day of the week in which the forced outage begins.
- Forced Outage Start Hour The hour of the day in which the forced outage begins. Choose a number from 1 to 24. 1 corresponds to the hour ending at 1 AM.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 110 of 118

Attachment Utah-1 Page 3 of 3

- Forced Outage Duration The number of hours in the month in which the generator will be offline due to an unexpected outage. The combined forced and maintenance outages must be less than 730 hours.
- Maintenance Outage Start Day The day of the week in which the maintenance outage begins.
- **Maintenance Outage Start Hour** The hour of the day in which the maintenance outage begins. Choose a number from 1 to 24. 1 corresponds to the hour ending at 1 AM.
- **Maintenance Hours** The number of hours in the month in which the generator will be offline due to a planned outage. The combined forced and maintenance outages must be less than 730 hours.

Other Tabs

The model has the following four other tabs:

- Rates and Riders: Contains the charges for the studied rate schedules and riders..
- Schedule 9: Contains charges for Schedules 31 & 9 and the applicable riders. Displays the calculated costs for Standby, Maintenance, Back-up, and Supplemental capacity and energy.
- Schedule 8: Contains charges for Schedules 31 & 8 and the applicable riders. Displays the calculated costs for Standby, Maintenance, Back-up, and Supplemental capacity and energy.
- Outage Table: Calculates the back-up and maintenance on-peak days.

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 111 of 118

	Innute	Monthly Billin	ng Units
Select Season From Drop Down	Season October through April	Total Demand Supplemental Demand Self Generation Demand	4,350 2,400 1,950
L Enter Peak Demand (kW)	.oad Characteristics 4,350 kW	Load Factor Supplemental Load Factor	54.7
Enter Load Factor	75 %	back-up On Peak Days Maintenance On Peak Days	
Ger	nerator Characteristics	Energy	100 100 0
Enter Net Capability (kW)	1,950 kW 100 %	Monthly Energy Supplemental Energy	2,381,025 958,125
Enter Forced Outage Start Day	Monday	Self Generation Energy	1,189,500
Start Hour (1 = Hour Ending 1AM) Duration (hours)	8 48 Hours	Back-up Energy Maintenance Energy	93,500 140,400
Enter Maintenance Outage Start Day Start Hour (1 = Hour Ending 1AM)	Monday 24		
Duration (hours)	72 Hours		

kWV kWV kWV Days Days KWh kWh kWh kWh

Note: The combined duration of the Forced and Maintenance Outages must be less than 730.

<u>On-Peak Percentage -</u> <u>Actual Hours</u> 23.81% 47.62%
<u>Off-Peak</u> All other times All other times
<u>Оп-Реак</u> 1:00РМ Моп-Fri 7:00АМ - 1:1:00РМ Моп-Fri
<u>Seasonal Peak Periods</u> May through September October through April

Schedule 8 - Large General Service at Primary Voltage October through April

			Standby Charges						
				Uni	ts	Rate	e	Cha	rge
Total Standby Charges			Base Charges						
Customer	\$	527	Customer		1	\$	527.00	\$	527
Eacilities	ŝ	6 533	Facilities		1,950	\$	3.35	\$	6,533
Power	ŝ		Power		1,950	\$	-	\$	-
Enormy	ç	-	Eperav	1	189,500	\$	-	s	-
Didese	¢	102	Lifeigy						
Total Coat	φ	7 252							
Total Cost	Φ	1,255	Pidors						
			Rivers	¢			1 3/1%	¢	_
			Schedule 94 - Energy Balancing Account	φ	-		0.290/	φ	
			Schedule 98 - REC Revenues Credit				-0.20/6	φ	-
			Schedule 193 - DSM Cost Adjustment		6,533		3.37%	\$	220
			Schedule 194 - DSM Cost Adj. Credit		6,533		-0.41%	æ	(27)
			Maintenance Charges			<u> </u>			
				Uni	ts	Rat	e	Cha	irge
Total Maintenance Cha	irges		Base Charges						
Customer	\$	-	Customer		1	\$	-	\$	-
Facilities	\$	-	Facilities		1,950	\$	-	\$	-
Power	s	1.670	Power		5,850	\$	0.28550	\$	1,670
Eperav	ŝ	4 406	Energy		140,400	\$ 0	.031382	\$	4,406
Riders	ŝ	244			,				
Total Cost	ę	6 320							
Total Cost	Ŷ	0,020	Riders						
			Schodule 94 - Energy Balancing Account	\$	6.076		1 34%	s	81
A I I I I	~	0.0450	Schedule 94 - Energy Balancing Accordit	Ψ	6.076		_0.28%	\$	(17)
\$/kWh	\$	0.0450	Schedule 98 - KEC Revenues Credit		6,070		2 2 70/	φ	205
			Schedule 193 - DSM Cost Adjustment		0,070		3.3170	ι Φ •	205
			Schedule 194 - DSM Cost Adj. Credit		6,076		-0.41%	Ф	(25)
			Forced Outage Charges						
				Un	its	Rat	e	Ch	arge
Total Forced Outage C	harg	es	Base Charges						
Customer	\$	-	Customer		1	\$	-	\$	-
Facilities	\$	-	Facilities		1,950	\$	-	\$	-
Power	ŝ	3 340	Power		5,850	\$	0.5710	\$	3,340
Eperav	÷	2 937	Energy		93.600	S (0.031382	\$	2,937
Bidate	é	2,357	Energy						,
Riders		6 520							
Total Cost	Þ	6,550	Pidore						
			Orbertula 04 Franzy Balancian Account	¢	6 278		1 34%		84
			Schedule 94 - Energy Balancing Account	φ	0,270		0.000/	, φ 	(40)
\$/kWh	\$	0.0698	Schedule 98 - REC Revenues Credit		0,270		-0.20%	, p	(10)
			Schedule 193 - DSM Cost Adjustment		6,278		3.37%	• •	212
			Schedule 194 - DSM Cost Adj. Credit		6,278		-0.41%	5	(26)
			Supplemental Charges						
				Un	its	Ra	te	Ch	arge
Total Supplemental Ch	harge	s	Base Charges						
Customer		62				1 \$	62.00	\$	62
Gudlonnon	\$	· · ·	Customer						10,128
Encilities	\$	10 128	Customer		2,400	\$	4.22	\$	
Facilities	\$ \$	10,128	Customer Facilities Power		2,400	\$ \$	4.22 8.93	\$ \$	21.432
Facilities Power	\$ \$ \$	10,128 21,432	Customer Facilities Power Eperar		2,400 2,400 958 125	\$ \$	4.22 8.93 0.031382	\$ \$ \$	21,432
Facilities Power Energy	\$ \$ \$ \$	10,128 21,432 30,068	Customer Facilities Power Energy		2,400 2,400 958,125	\$ \$ \$	4.22 8.93 0.031382	\$ \$ \$	21,432 30,068
Facilities Power Energy Riders	\$ \$ \$ \$	10,128 21,432 30,068 2,271	Customer Facilities Power Energy		2,400 2,400 958,125	\$ \$ \$	4.22 8.93 0.031382	\$ \$ \$	21,432 30,068
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961	Customer Facilities Power Energy		2,400 2,400 958,125	\$ \$ \$	4.22 8.93 0.031382	\$ \$ \$	21,432 30,068
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961	Customer Facilities Power Energy		2,400 2,400 958,125	\$	4.22 8.93 0.031382	\$ \$ \$ \$ \$ \$	21,432 30,068
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account	\$	2,400 2,400 958,125 51,500	\$ \$ \$	4.22 8.93 0.031382 1.34%	\$ \$ \$	21,432 30,068 690
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668	Customer Facilities Power Energy Riders Schedule 94 - Energy Batancing Account Schedule 98 - REC Revenues Credit	\$	2,400 2,400 958,125 51,500 51,500	\$ \$ \$	4.22 8.93 0.031382 1.34% -0.28%	\$ \$ \$	21,432 30,068 690 (144)
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$	0.0668 0.0668	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment	\$	2,400 2,400 958,125 51,500 51,500 61,628	\$	4.22 8.93 0.031382 1.34% -0.28% 3.20%	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144) 1,972
Facilities Power Energy Riders Total Cost \$/kWh	\$ \$ \$ \$ \$	10,128 21,432 30,068 <u>2,271</u> 63,961 0.0668	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 94 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adjustment	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$	4.22 8.93 0.031382 1.34% -0.28% 3.20% -0.40%	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144) 1,972 (247)
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$	10,128 21,432 30,068 <u>2,271</u> 63,961	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adjustment	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$ \$	4.22 8.93 0.031382 1.34% -0.28% 3.20% -0.40%	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144 1,972 (247)
Facilities Power Energy Riders Total Cost	\$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 94 - Energy Balancing Account Schedule 193 - DSM Cost Adjustment Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adjustment	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$	4.22 8.93 0.031382 1.34% -0.28% 3.20% -0.40%	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144 1,972 (247
Facilities Power Energy Riders Total Cost \$/kWh	\$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adju Credit	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$	4.22 8.93 0.031382 1.349 -0.289 3.209 -0.409	\$ \$ \$ 6 6 8 8 8 6 8 8 8 8 8 8 8 8 8 8 8	21,432 30,068 690 (144 1,972 (247
Facilities Power Energy Riders Total Cost \$/kWh	\$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 93 - DSM Cost Adjustment Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$	4.22 8.93 0.031382 1.349 -0.289 3.209 -0.409	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144 1,972 (247
Facilities Power Energy Riders Total Cost \$/kWh Customer	\$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 98 - DSM Cost Adjustment Schedule 194 - DSM Cost Adju Credit Grand Total	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$	4.22 8.93 0.031382 1.349 -0.289 3.209 -0.409	\$ \$ \$ 6 6 5 5 6 6 5 5 6 6 5 5 6 6 5 5 6 6 5 5 6 6 6 5 5 5 6 6 5	21,432 30,068 690 (144 1,972 (247
Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities	\$ \$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668 589 16,661	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Grand Total	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$\$\$	4.22 8.93 0.031382 1.349 -0.289 3.209 -0.409	\$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144 1,972 (247
Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities Power	\$ \$ \$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668 589 16,661 26,443	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adjustment Schedule 194 - DSM Cost Adjustment	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$\$\$	4.22 8.93 0.031382 1.34% -0.28% 3.20% -0.40%	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144; 1,972 (247)
Facilities Power Energy Riders Total Cost S/kWh Customer Facilities Power Energy	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668 589 16,661 26,443 37,411	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Grand Total	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$ \$	4.22 8.93 0.031382 1.349 -0.289 3.209 -0.409	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$	21,432 30,068 690 (144; 1,972 (247)
Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities Power Energy Riders	\$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$ \$	10,128 21,432 30,068 2,271 63,961 0.0668 589 16,661 26,443 37,411 2,961	Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Grand Total	\$	2,400 2,400 958,125 51,500 51,500 61,628 61,628	\$ \$ \$	4.22 8.93 0.031382 1.349 -0.289 3.209 -0.409	\$\$\$ \$\$ 6 6 5 \$ 8 \$\$ \$\$\$\$\$\$\$\$\$\$\$\$\$	21,432 30,068 690 (144) 1,972 (247)

\$/kWh \$ 0.0705

 Inputs

 Select Season From Drop Down
 May through September

 Select Season From Drop Down
 Load Characteristics

 Enter Peak Demand (kV)
 Load Characteristics

 Enter Peak Demand (kV)
 19,500

 Enter Peak Demand (kV)
 80 %

 Enter Coad Factor
 190 %

 Enter Coad Start Day
 Monday

 Enter Maintenance Outage Start Day
 Monday

19,500 kW 12,000 kW 7,500 kW 80 % 67.5 % 2 Days 1 Days

Total Demand Self Generation Demand Self Generation Demand Load Factor Back-up On Peak Days Maintenance On Peak Days

Monthly Billing Units

11,388,000 kWh 5,913,000 kWh 4,845,000 kWh 360,000 kWh 270,000 kWh

Energy Monthly Energy Supplemental Energy Self Generation Energy Back-up Energy Maintenance Energy

Note: The combined duration of the Forced and Maintenance Outages must be less than 730.

On-Peak Percentage - Actual Hours 23.81% 47.62%
<u>Off-Peak</u> All other times All other times
<u>On-Peak</u> 1:00PM - 9:00PM Mon-Fri 7:00AM - 11:00PM Mon-Fri
<u>Seasonal Peak Periods</u> May through September October through April

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 113 of 118

Schedule 9 - General Service at Transmission Voltage May through September

		Standby Charges	Unite	Rate	Charge
Tetel Cteredby Character		Roop Charges	Units	nate	Ghaige
Total Standby Charges		Base Charges	4	¢ 500.00	¢ 6
Customer	\$ 590	Customer	7.500	\$ 390.00	φ
acilities	\$ 14,250	Facilities	7,500	¢ 1.50	φ 1~4,2 φ
ower	\$-	Power	7,500	\$ - •	\$ ·
nergy	\$ -	Energy	4,845,000	ş -	\$ ·
iders	\$ 422				
otal Cost	\$ 15,262				
		Riders			
		Schedule 94 - Energy Balancing Account	\$-	1.47%	\$
		Schedule 98 - REC Revenues Credit	· _	-0.31%	\$
		Cabadula 402 DEM Cast Adjustment	14.250	3 37%	i e ,
		Schedule 193 - DSW Cost Adjustment	14,250	0.419	υψ - (¢
		Schedule 194 - DSM Cost Adj. Credit	14,250	-0.417	ο Φ
		Maintenance Charges	11.9.	D-4-	Charma
		Basa Charman	Units	Rate	Charge
otal Maintenance Chai	rges	Base Charges			¢
Customer	\$ -	Customer			\$
acilities	\$ -	Facilities	7,500	\$ -	\$
ower	\$ 1,682	Power	7,500	\$ 0.22425	\$ 1,6
inergy	\$ 7,852	Energy	270,000	\$ 0.029083	\$ 7,
tiders	\$ 393				
otal Cost	\$ 9.927				
0101 0001	÷ 0,021	Biders			
		Schodulo 04 Enorgy Polonoing Account	¢ 0.534	1 470	68.
		Schedule 94 - Energy balancing Account	φ 3,554	0.940	υψ / e
/kWh	\$ 0.0368	Schedule 98 - REC Revenues Credit	9,534	-0.315	60 60
		Schedule 193 - DSM Cost Adjustment	9,534	3.379	65
		Schedule 194 - DSM Cost Adj. Credit	9,534	-0.41%	6\$
		Forced Outage Charges			
			Units	Rate	Charge
Fotal Forced Outage Cl	harges	Base Charges			
Customor	¢ .	Customer		1\$-	s
	φ -	Ecolities	7 500	· ·	s
acinties	a -	Facilities	15,000	÷ 0 4 4 9 6	. •
Power	\$ 6,728	Power	15,000	\$ 0.4465)
Energy	\$ 10,470	Energy	360,000	\$ 0.029083	5 \$ 10,
Riders	\$ 709				
Fotal Cost	\$ 17,906				
		Riders			
		Schedule 94 - Energy Balancing Account	\$ 17.197	1.479	% \$
1.10 <i>0</i>	¢ 0.0407	Schodulo 98 - REC Revenues Credit	17 197	-0.319	% \$
wkvvn	\$ 0.0497	Schedule 96 - REC Revenues credit	17,107	3 3 79	
		Schedule 193 - DSM Cost Adjustment	17,197	3.37	/0 . v . e
		Schedule 194 - DSM Cost Adj. Credit	17,197	-0.41	/o
		Supplemental Charges			
			Units	Rate	Charge
otal Supplemental Ch	arges	Base Charges			
Customer	\$ 226	Customer		1 \$ 226.00)\$
acilities	\$ 23,280	Facilities	12,000)\$ 1.94	1 \$ 23,
ower	\$ 146 160	Power	12,000) \$ 12.18	3 \$ 146.
norav	\$ 171 969	Energy	5 913 000	\$ 0.02908	3 \$ 171
Liiciyy Nidaas	¢ 171,000	Elicia)	0,010,000		- - ,
doers	φ 13,204				
otal Cost	\$ 354,919				
		Riders			
		Schedule 94 - Energy Balancing Account	\$ 318,129	€ 1.47 ⁰	%\$4
/kWh	\$ 0.0600	Schedule 98 - REC Revenues Credit	318,129	-0.31	%\$
		Schedule 193 - DSM Cost Adjustment	341,409	3.21	% \$ 10
		Schedule 194 - DSM Cost Adj. Credit	341,409	-0.40	% \$ (1
		Grand Total			
Customer	\$ 816				
Facilities	\$ 37,530				
Power	\$ 154,569				
Enormy	\$ 190 292				
Energy	\$ 190,292				
Kiders	\$ 14,807				
	C 200 044				

\$/kWh

\$ 0.0608

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 115 of 118

	struct	Monthly Bill	ing Units
Select Season From Drop Down	nipus Season May through September	Total Demand Supplemental Demand Soft Constation Demand	25,000 kW - kW 25,000 kW
	Load Characteristics	Load Factor	80 %
Enter Peak Demand (kW)	25,000 kW	Supplemental Load Factor	0.0%
Enter Load Factor	80 %	Back-up On Peak Days	2 Days
	1.0222020200000000000000000000000000000	Maintenance On Peak Days	2 Days
Ō	merator Characteristics	Energy	
Enter Net Capability (kW)	25,000 kW	Monthly Energy	14,600,000 kWh
Enter Generator Load Factor	80 %	Supplemental Energy	
Enter Forced Outage Start Day	Monday	Self Generation Energy	12,680,000 KVVN
Start Hour (1 = Hour Ending 1AM)	12	Back-up Energy	960,000 KVVN
Duration (hours)	48 Hours	waintenance Energy	800'000 VAN
Enter Maintenance Outage Start Day	Monday		
Start Hour (1 = Hour Ending 1AM)	24		
Duration (hours)	48 Hours		

Note: The combined duration of the Forced and Maintenance Outages must be less than 730.

<u>On-Peak Percentage -</u> <u>Actual Hours</u> 23.81% 47.62%
<u>Off-Peak</u> All other times All other times
<u>On-Peak</u> 1.00PM Mon-Fri 7.00AM - 11.00PM Mon-Fri
<u>Seasonal Peak Periods</u> May through September October through April

Schedule 9 - General Service at Transmission Voltage May through September

		Standby Charges			
			Units	Rate	Charge
otal Standby Char	ges	Base Charges			
Customer	\$ 590	Customer	1	\$ 590.00	\$ 5
acilities	\$ 47,500	Facilities	25,000	\$ 1.90	\$ 47,5
ower	\$ -	Power	25,000	\$ -	\$-
nerav	s -	Energy	12,680,000	\$-	\$-
Viders	\$ 1406				
Tetel Cost	\$ 49,496				
otar Cost	\$ 45,450	Bidore			
		Rideis	*	1 479/	e
		Schedule 94 - Energy Balancing Account	φ -	0.040/	· · ·
		Schedule 98 - REC Revenues Credit	-	-0.31%	, , , , , , , , , , , , , , , , , , ,
		Schedule 193 - DSM Cost Adjustment	47,500	3.37%	5 35 1,6
		Schedule 194 - DSM Cost Adj. Credit	47,500	-0.41%	, \$ (1
		Maintenance Charges			
		mannenence energee	Units	Rate	Charge
otal Maintenance	Charges	Base Charges			
Customer	\$-	Customer	1	\$-	s -
acilities	s -	Facilities	25,000	\$-	\$-
Power	\$ 11 213	Power	50,000	\$ 0.22425	\$ 11.2
Dorgy	\$ 27 920	Energy	960 000	\$ 0.029083	\$ 27.9
Linergy	\$ 21,520 \$ 1,610	End Bi	225,000		
	\$ 1,012 \$ 40.745				
otal Cost	\$ 40,745	Didam			
		Riders			
		Schedule 94 - Energy Balancing Account	\$ 39,132	1.47%	05 5
ø/kWh	\$ 0.0424	Schedule 98 - REC Revenues Credit	39,132	-0.31%	6\$ (1
		Schedule 193 - DSM Cost Adjustment	39,132	3.37%	6\$1,3
		Schedule 194 - DSM Cost Adj. Credit	39,132	-0.41%	6\$ (1
		· ·			
		Forced Outage Charges	Units	Rate	Charge
T-t-l Farmed Outer	na Charman	Base Charges	onno	itato	+1147 g+
Total Forced Outag	Je Charges	Custemar		1 \$ -	\$.
Justomer	- -	Customer	25.000	÷ .	ŝ.
Facilities	\$ -	Facilities	20,000		
Power	\$ 22,425	Power	50,000	\$ 0.4465	0 0 ZZ,4
Energy	\$ 27,920	Energy	960,000	\$ 0.029083	\$ 27,8
Riders	\$ 2,074				
Total Cost	\$ 52,419				
		Riders			
		Schedule 94 - Energy Balancing Account	\$ 50,345	1.479	6\$7
\$/kWh		Schedule 98 - REC Revenues Credit	50,345	-0.319	6\$ (1
p100011	S 0.0546			2 270	/ e 10
	\$ 0.0546	Schedule 193 - DSM Cost Adjustment	50 345	3.3/7	0 0 1.0
	\$ 0.0546	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345	-0.419	6\$ 1,0
	\$ 0.0546	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345	-0.41%	6 \$ 1,0 6 \$ (2
	ş 0.0546	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges	50,345 50,345 Units	-0.419	6 \$ (;
Total Supplementa	\$ 0.0546	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges	50,345 50,345 Units	-0.419 Rate	6 \$ 1,4 6 \$ (2 Charge
Total Supplementa	\$ 0.0546	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customar	50,345 50,345 Units	-0.419 Rate	6 \$ (2 6 \$ (2 Charge
Total Supplementa Customer	\$ 0.0546 al Charges \$ 226	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Equilities	50,345 50,345 Units	-0.419 Rate	6 \$ (2 6 \$ (2 Charge) \$ 2
Total Supplementa Customer Facilities	\$ 0.0546 al Charges \$ 226 \$ -	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities	50,345 50,345 Units		6 \$ (2 Charge) \$ 2 4 \$
Total Supplementa Customer Facilities Power	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ -	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power	50,345 50,345 Units - -	Rate 1 \$ 226.00 \$ 1.94 \$ 12.16	6 \$ (2 Charge) \$ 2 4 \$ 3 \$
Total Supplementa Customer Facilities Power Energy	\$ 0.0546 Id Charges \$ 226 \$ - \$ - \$ -	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy	50,345 50,345 Units - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 12.18 \$ 0.029083	6 \$ 1,5 6 \$ (2 Charge) \$ 2 4 \$ 3 \$
Total Supplementa Customer Facilities Power Energy Riders	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ -	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy	50,345 50,345 Units - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.94 \$ 12.16 \$ 0.029083	6 \$ (2 Charge) \$ 2 4 \$ 3 \$
Total Supplementa Customer Facilities Power Energy Riders Total Cost	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ 226 \$ - \$ - \$ 226	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy	50,345 50,345 Units - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 12.18 \$ 0.029080	6 \$ (2 Charge) \$ 2 1 \$ 3 \$ 3 \$
Total Supplementa Customer Facilities Power Energy Riders Total Cost	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ - \$ - \$ 226 \$ - \$ - \$ - \$ - \$ - \$ - \$ - \$ -	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders	50,345 50,345 Units - - -	Rate Rate 1 \$ 226.00 \$ 1.94 \$ 12.18 \$ 0.029083	6 \$ (2 Charge) \$ 2 4 \$ 3 \$ 3 \$
Total Supplementa Customer Facilities Power Energy Riders Total Cost	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ 226 \$ - \$ 226	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account	50,345 50,345 Units - - - -		 (a) (a) (b) (b) (c) (c) (c) (c) (c) (c) (c) (c) (c) (c
Total Supplementa Customer Facilities Power Energy Riders Total Cost	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ 226 #DIV(01	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit	50,345 50,345 Units - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 12.18 \$ 0.029083 1.475 -0.315	6 \$ (2 Charge) \$ 2 3 \$ 3 \$ 3 \$ % \$
Total Supplementa Customer =acilities =ower Energy Riders Total Cost	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ 226 #DIV/0!	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 98 - REC Revenues Credit	50,345 50,345 Units - - - - - - - - - - - - - - - - - - -	Rate Rate 1 \$ 226.00 \$ 1.94 \$ 12.16 \$ 0.029083 1.477 -0.317 3.210	 (a) \$ (2) (b) \$ (2) (c) \$ (2)
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ 226 #DIV/0!	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adju Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 193 - DSM Cost Adjustment Schedule 193 - DSM Cost Adjustment	50,345 50,345 Units - - - - - - - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 12.18 \$ 0.029083 1.476 -0.316 3.211 -0.400	 (a) \$ (c) (c) \$ (c) (c) <li(c)< li=""> <li(< td=""></li(<></li(c)<>
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ - \$ 226 #DIV/0!	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 12.16 \$ 0.029083 1.477 -0.316 3.219 -0.405	(3 \$ (1) Charge (1) \$:: 1 \$ 3 \$ 3 \$ % \$ % \$ % \$ % \$ % \$
Total Supplementa Customer Facilities Power Energy Riders Total Cost S/kWh	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ 226 #DIV/0!	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.218 \$ 0.029083 1.479 -0.315 3.216 -0.405	 (% \$ () Charge () \$ () \$
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ 226 #DIV/01 \$ #DIV/01	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Schedule 194 - DSM Cost Adj. Credit Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 94 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.2.16 \$ 0.029083 1.476 -0.313 3.217 -0.405	 (a) \$ (c) (b) \$ (c) (c) \$ (c) (c) <li(c)< li=""> (c) (c)</li(c)<>
Total Supplementa Customer Facilities Power Energy Riders Total Cost S/kWh S/kWh	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ 226 # - \$ - \$ - \$ 226 # DIV/0!	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 198 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.24 \$ 0.029083 1.475 -0.315 -0.405	 (% \$ (% Charge () \$ (% <
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ 226 # - \$ 226 #DIV/01 \$ 816 \$ 47,500 \$ 229	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Schedule 194 - DSM Cost Adj. Credit Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 94 - Rec Revenues Credit Schedule 194 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.24 \$ 0.029083 1.47 -0.31 3.212 -0.405	<pre>% \$ (? Charge 0 \$: 3 \$ 3 \$ % \$ % \$ % \$ % \$ % \$</pre>
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities Power	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ 226 # 226 # DIV/0! \$ 816 \$ 47,500 \$ 33,638 \$ 33,638	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.24 \$ 0.029083 1.47 -0.31 3.21 -0.405	 5 (2 Charge 0 \$ 2 4 \$ 3 \$ 3 \$ % \$ % \$ % \$ % \$
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities Power Energy	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ 226 #DIV/01 #DIV/01 \$ 816 \$ 47,500 \$ 33,638 \$ 55,840	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - -	3.377 -0.419 Rate 1 \$ 226.00 1 \$ 226.00 \$ 1 \$ 226.00 \$ 1 \$ 0.029083 1.475 -0.315 -0.315 -0.405	 (4) (5) (7) (7)
Total Supplementa Customer Facilities Power Energy Riders Total Cost \$/kWh Customer Facilities Power Energy Riders	\$ 0.0546 al Charges \$ 226 \$ - \$ - \$ - \$ 226 * 226 * 226 * 226 * 226 * 226 * 226 * 226 * 3.5 * 3.5 * 47,500 \$ 33,638 \$ 55,840 \$ 5,092	Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit Supplemental Charges Base Charges Customer Facilities Power Energy Riders Schedule 94 - Energy Balancing Account Schedule 98 - REC Revenues Credit Schedule 193 - DSM Cost Adjustment Schedule 194 - DSM Cost Adj. Credit	50,345 50,345 Units - - - - - - - - - - - -	Rate 1 \$ 226.00 \$ 1.94 \$ 1.24 \$ 0.029083 1.47 -0.313 3.21 -0.405	(*) \$ (*) (*) \$ (*) (*) \$ (*) (*) \$ (*) (*) \$ (*)

\$/kWh \$ 0.0744

Attachment Utah-3 Page 1 of 2

Rocky Mountain Power Utah - Schedule No. 31

1. Create reservation charge to reflect performance of best unit and revise T&D charges to reflect diversity.

		Current Power	Revised Power	Current	Revised
	Voltage	Reservation	Reservation	Facilities	Facilities
<u>Line</u>	Level	<u>\$/kW/Mo</u>	<u>\$/kW/Mo</u>	<u>\$/kW</u>	<u>\$/kW</u>
1	Primary	\$0.00	\$0.5710	\$3.35	\$1.16
2	Transmission	\$0.00	\$0.4485	\$1.90	\$0.00

Notes:

1. Reservation charge only includes power costs.

2. Customer will pay facilities charge for dedicated facilities costs .

2. Modify back-up charges for seasonal difference and recovery of diversified T&D costs

		Current Annual	Estimated On-Peak	Estimated On-Peak
	Voltago	Dii-Peak Bookup	Bookup	Rockup
	vollage	билир		
	Level	<u>\$/KW/Day</u>	<u>\$/KW/Day</u>	<u>\$/KW/Day</u>
6	Primary	\$0.5710	\$0.7619	\$0.5708
7	Transmission	\$0.4485	\$0.6732	\$0.4796
		Current		
		Annual	Estimated	Estimated
		On-Peak	On-Peak	On-Peak
		Annual	Summer	Winter
	Voltage	Maintenance	Maintenance	Maintenance
	Level	<u>\$/kW/Day</u>	<u>\$/kW/Day</u>	<u>\$/kW/Day</u>
8	Primary	\$0.2855	\$0.3810	\$0.2854
9	Transmission	\$0.2243	\$0.3366	\$0.2398

Maurice Brubaker Docket Nos. 13-035-184 | 13-035-196 UIEC Exhibit COS 2.10 (MEB-10) Page 118 of 118



RMP Standby Demand Charges Compared with Charges Associated with Suggested Revision

Assumptions

Transmission customer has a 25,000 kW on-site generator. Primary Customer has a 1,950 kW on-site generator. Maximum of 23 on peak days in the month.