RAP Energy solutions for a changing world

Standby Rates for Combined Heat and Power Systems

Economic Analysis and Recommendations for Five States

Authors
James Selecky
Kathryn Iverson
Ali Al-Jabir

February 2014

ORNL/TM-2013/583

Standby Rates for Combined Heat and Power Systems:

Economic Analysis and Recommendations for Five States

Prepared by Brubaker & Associates, Inc.
and the Regulatory Assistance Project
for Oak Ridge National Laboratory

Lead authors: James Selecky, Kathryn Iverson, and Ali Al-Jabir, Brubaker & Associates, Inc.

Project manager, contributor, and technical editor: Lisa Schwartz, Regulatory Assistance Project

Final editor: Richard Sedano, Regulatory Assistance Project

Oak Ridge National Laboratory Technical Project Officer: Patricia Garland

Special thanks to the Public Utility Commissions of Arkansas, Colorado, New Jersey, Ohio, and Utah for participating in this project. Additional valuable comments and reviews were provided by Cliff Haefke, Bruce Hedman, Katrina Pielli, Patti Garland, and Michael Starke. Camille Kadoch, John Gerhard and Dave Lamont of RAP contributed important pieces to the final report.

RAP

Table Of Contents

List of Figures

List of Tables

List of Acronyms and Abbreviations

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

Foreword

Improvements 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

Standby, or partial requirements, service is the set of retail electric products for customers who operate onsite, non-emergency generation. Utility standby rates cover some or all of the following 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.

1 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

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.

- 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 customer-generators 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.

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

Standby, 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.

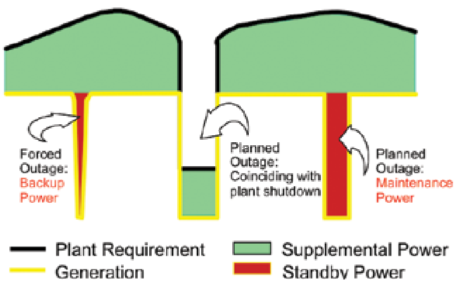
Utility standby rates cover some or all of the following standby services (see Figure 1):[4]

- ***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 customer's 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 Order[6] 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 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.

Figure 1

Illustration of Self-Generating Customers' Purchase Power Requirements[5]



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 energy-efficient 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 customer-generators 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.

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.

Table 2

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*

Both customers, FR1 and FR2, purchase full 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

Standby rates are typically designed to recover the fully allocated embedded costs that the utility incurs to provide standby service to self-generating 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 delivery[10] 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 cost-related 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 long-run 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

10 "Delivery" as used in this paper is synonymous with "transmission and distribution."

11 18 C.F.R § 292.305 (1)(i)(ii) and (2).

Table 3

Impact of Coincidence Factor on Demand Charges

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 non-coincident 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 demand-related 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 long-run 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 demand-related generation costs underlying the applicable full-requirements 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 self-generating 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 on-site 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

BAI 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

Entergy 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

RAP

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 on-site 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
   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 transmission-level 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:

1. 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 self-generating 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 energy-related 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 20-day 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 time-of-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

Public 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;
2. 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 self-dispatch 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:

1. 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 self-generating 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

Jersey 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 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:

1. **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 full-requirements 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

RAP

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

AEP 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 third-party 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 energy-only 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/kW[15] (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).

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

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

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-of-use 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:

1. **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 full-requirements 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 customer-specific 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 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 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:

1. 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 full-requirements 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 over-forecast 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

Rocky 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:

1. ***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
3. 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 on-peak 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 self-dispatch, 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 self-generating 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 30-day 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 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.

References

Johnston, L., Takahashi, K., Weston, F., and Murray, C. (2008). Rate Structures for Customers with Onsite Generation: Practice and Innovation. California Energy Commission, PIER Energy Systems Integration Program. CEC-500-2008-059. National Renewable Energy Laboratory, Golden, CO. Available at: http://www.energy.ca.gov/2008publications/CEC-500-2008-058/CEC-500-2008-058.PDF.

Lazar, J. (2013). Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516.

Stanton, T. (2012). Electric Utility Standby Rates: Updates for Today and Tomorrow. Silver Spring, MD: National Regulatory Research Institute. Available at: http://www.nrri.org/documents/317330/94c186ab-4f16-4a69-8e8c-ece658e752b1.

Weston, F., Bluestein, J., Hedman, B., Hite, R. (2009). Standby Rates for Customer-Sited Resources: Issues, Considerations and the Elements of Model Tariffs. The Regulatory Assistance Project, Montpelier, VT. Available at: http://www.epa.gov/chp/documents/standby_rates.pdf.

The White House, Office of the Press Secretary (2012) President Obama Signs Executive Order Promoting Industrial Energy Efficiency. [press release]. Retrieved from: http://www.whitehouse.gov/the-press-office/2012/08/30/president-obama-signs-executive-order-promoting-industrial-energy-effici

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

RAP

The Regulatory Assistance Project
Beijing, China • Berlin, Germany • Brussels, Belgium
Montpelier, Vermont USA • New Delhi, India

50 State Street, Suite 3
Montpelier, Vermont 05602
802-223-8199
www.raponline.org

Entergy Arkansas, Inc.
Standby Rate Model

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.

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.

Tabs

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.

Inputs

	Season	
Select Season From Drop Down	Summer Period	
	Load Characteristics	
Enter Peak Demand (kW)	1,500	kW
Enter Load Factor	70	%
	Generator Characteristics	
Enter Net Capability (kW)	700	kW
Enter Backup Hours	146	Hours
Enter Maintenace Hours	73	Hours

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

Monthly Billing Units

Total Demand	1,500	kW
Supplmental Demand	800	kW
Baseload Demand	700	kW
Load Factor	70.00	%
Supplemental Load Factor	43.75	%
Monthly Energy	766,500	kWh
Supplemental Energy	255,500	kWh
Baseload Energy	357,700	kWh
Backup Energy	102,200	kWh
Maintenance Outage Energy	51,100	kWh
Backup Duration	7	Days
Maintenance Duration	4	Days

Large General Service at Primary Voltage
Summer Period

Reservation Charges

Total Reservation Charges	
Customer	$ 412
Demand	$ 1,337
Energy	$ -
Riders	$ (13)
Total Cost	$ 1,736

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Customer	1	$ 412.37	$ 412	1	$ 412.37	$ 412
Demand	700	$ 2.79	$ 1,953	693	$ 1.93	$ 1,337
Energy	357,700	$ -	$ -	354,123	$ -	$ -
Riders						
Capacity Acquisition Rider	1,750	-0.7656%	$ (13)			

Maintenance Charges

Total Maintenance Charges	
Demand	$ 275
Energy	$ 1,094
Riders	$ 1,398
Total Cost	$ 2,766
$/kWh	$ 0.05414

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	2,800	$ 0.1275	$ 357	2,772	$ 0.10	$ 275
Energy	51,100	$ 0.02162	$ 1,105	50,589	$ 0.02162	$ 1,094
Riders						
Energy Cost Recovery Rider ($/kWh)	51,100	$ 0.01783	$ 911	50,589	$ 0.01783	$ 902
Energy Efficiency Cost Rate Rider ($/kWh)	51,100	$ 0.00178	$ 91	50,589	$ 0.00178	$ 90
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	700	$ -	$ -	693	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	51,100	$ 0.00005	$ 3	50,589	$ 0.00005	$ 3
Production Cost Allocation Rider ($/kWh)	51,100	$ 0.00566	$ 289	50,589	$ 0.00566	$ 286
Capacity Acquisition Rider	1,497	-0.7656%	$ (11)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700	$ 0.18505	$ 130	693	$ 0.1851	$ 128

Backup Charges

Total Backup Charges	
Demand	$ 1,303
Energy	$ 2,187
Riders	$ 2,662
Total Cost	$ 6,153
$/kWh	$ 0.06021

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	4,900	$ 0.297	$ 1,455	4,851	$ 0.27	$ 1,303
Energy	102,200	$ 0.02162	$ 2,210	101,178	$ 0.02162	$ 2,187
Riders						
Energy Cost Recovery Rider ($/kWh)	102,200	$ 0.01783	$ 1,822	101,178	$ 0.01783	$ 1,804
Energy Efficiency Cost Rate Rider ($/kWh)	102,200	$ 0.00178	$ 182	101,178	$ 0.00178	$ 180
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	700	$ -	$ -	693	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	102,200	$ 0.00005	$ 5	101,178	$ 0.00005	$ 5
Production Cost Allocation Rider ($/kWh)	102,200	$ 0.00566	$ 578	101,178	$ 0.00566	$ 573
Capacity Acquisition Rider	3,619	-0.7656%	$ (28)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700	$ 0.18505	$ 130	693	$ 0.1851	$ 128

Supplemental Charges

Total Supplemental Charges	
Demand	$ 6,732
Energy	$ 5,469
Riders	$ 7,797
Total Cost	$ 19,997
$/kWh	$ 0.07827

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	800	$ 9.36	$ 7,488	792	$ 8.50	$ 6,732
Energy	255,500	$ 0.02162	$ 5,524	252,945	$ 0.02162	$ 5,469
Riders						
Energy Cost Recovery Rider ($/kWh)	255,500	$ 0.01783	$ 4,556	252,945	$ 0.01783	$ 4,510
Energy Efficiency Cost Rate Rider ($/kWh)	255,500	$ 0.00178	$ 455	252,945	$ 0.00178	$ 450
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	700	$ 1.96	$ 1,372	693	$ 1.96	$ 1,358
Federal Litigation Consulting Fee Rider ($/kWh)	255,500	$ 0.00005	$ 13	252,945	$ 0.00005	$ 13
Production Cost Allocation Rider ($/kWh)	255,500	$ 0.00566	$ 1,446	252,945	$ 0.00566	$ 1,432
Capacity Acquisition Rider	12,329	-0.7656%	$ (94)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700	$ 0.18505	$ 130	693	$ 0.1851	$ 128

Municipal Franchise Adjustment Rider

	Units	Rate	Charge
Reservation Charges	1,736	4.250%	$ 74
Maintenance Charges	2,766	4.250%	$ 118
Backup Charges	6,153	4.250%	$ 262
Supplemental Charges	19,997	4.250%	$ 850

Grand Total

Customer	**$ 412**
Demand	**$ 9,648**
Energy	**$ 8,750**
Riders	**$ 13,146**
Total	**$ 31,956**
$/kWh	**0.07817**

	Inputs	
	Season	
Select Season From Drop Down	Other Period	
	Load Characteristics	
Enter Peak Demand (kW)	1,500	kW
Enter Load Factor	70	%
	Generator Characteristics	
Enter Net Capability (kW)	700	kW
Enter Backup Hours	146	Hours
Enter Maintenace Hours	73	Hours

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

Monthly Billing Units		
Total Demand	1,500	kW
Supplmental Demand	800	kW
Baseload Demand	700	kW
Load Factor	70.00	%
Supplemental Load Factor	43.75	%
Monthly Energy	766,500	kWh
Supplemental Energy	255,500	kWh
Baseload Energy	357,700	kWh
Backup Energy	102,200	kWh
Maintenance Outage Energy	51,100	kWh
Backup Duration	7	Days
Maintenance Duration	4	Days

Large General Service at Primary Voltage

Other Period

Reservation Charges

Total Reservation Charges	
Customer	$ 412
Demand	$ 1,337
Energy	$ -
Riders	$ (13)
Total Cost	$ 1,736

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Customer	1	$ 412.37	$ 412	1	$ 412.37	$ 412
Demand	700	$ 2.79	$ 1,953	693	$ 1.93	$ 1,337
Energy	357,700	$ -	$ -	354,123	$ -	$ -
Riders						
Capacity Acquisition Rider	1,750	-0.7656%	$ (13)			

Maintenance Charges

Total Maintenance Charges	
Demand	$ 230
Energy	$ 778
Riders	$ 1,400
Total Cost	$ 2,409
$/kWh	$ 0.04713

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	2,800	$ 0.1113	$ 312	2,772	$ 0.08	$ 230
Energy	51,100	$ 0.01538	$ 786	50,589	$ 0.01538	$ 778
Riders						
Energy Cost Recovery Rider ($/kWh)	51,100	$ 0.01783	$ 911	50,589	$ 0.01783	$ 902
Energy Efficiency Cost Rate Rider ($/kWh)	51,100	$ 0.00178	$ 91	50,589	$ 0.00178	$ 90
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	700	$ -	$ -	693	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	51,100	$ 0.00005	$ 3	50,589	$ 0.00005	$ 3
Production Cost Allocation Rider ($/kWh)	51,100	$ 0.00566	$ 289	50,589	$ 0.00566	$ 286
Capacity Acquisition Rider	1,136	-0.7656%	$ (9)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700	$ 0.18505	$ 130	693	$ 0.1851	$ 128

Backup Charges

Total Backup Charges	
Demand	$ 1,080
Energy	$ 1,556
Riders	$ 2,669
Total Cost	$ 5,305
$/kWh	$ 0.05191

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	4,900	$ 0.251	$ 1,230	4,851	$ 0.22	$ 1,080
Energy	102,200	$ 0.01538	$ 1,572	101,178	$ 0.01538	$ 1,556
Riders						
Energy Cost Recovery Rider ($/kWh)	102,200	$ 0.01783	$ 1,822	101,178	$ 0.01783	$ 1,804
Energy Efficiency Cost Rate Rider ($/kWh)	102,200	$ 0.00178	$ 182	101,178	$ 0.00178	$ 180
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	700	$ -	$ -	693	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	102,200	$ 0.00005	$ 5	101,178	$ 0.00005	$ 5
Production Cost Allocation Rider ($/kWh)	102,200	$ 0.00566	$ 578	101,178	$ 0.00566	$ 573
Capacity Acquisition Rider	2,765	-0.7656%	$ (21)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700	$ 0.18505	$ 130	693	$ 0.1851	$ 128

Supplemental Charges

Total Supplemental Charges	
Demand	$ 5,599
Energy	$ 3,890
Riders	$ 7,817
Total Cost	$ 17,307
$/kWh	$ 0.06774

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	800	$ 7.93	$ 6,344	792	$ 7.07	$ 5,599
Energy	255,500	$ 0.01538	$ 3,930	252,945	$ 0.01538	$ 3,890
Riders						
Energy Cost Recovery Rider ($/kWh)	255,500	$ 0.01783	$ 4,556	252,945	$ 0.01783	$ 4,510
Energy Efficiency Cost Rate Rider ($/kWh)	255,500	$ 0.00178	$ 455	252,945	$ 0.00178	$ 450
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	700	$ 1.96	$ 1,372	693	$ 1.96	$ 1,358
Federal Litigation Consulting Fee Rider ($/kWh)	255,500	$ 0.00005	$ 13	252,945	$ 0.00005	$ 13
Production Cost Allocation Rider ($/kWh)	255,500	$ 0.00566	$ 1,446	252,945	$ 0.00566	$ 1,432
Capacity Acquisition Rider	9,618	-0.7656%	$ (74)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	700	$ 0.18505	$ 130	693	$ 0.1851	$ 128

Municipal Franchise Adjustment Rider

	Units	Rate	Charge
Reservation Charges	1,736	4.250%	$ 74
Maintenance Charges	2,409	4.250%	$ 102
Backup Charges	5,305	4.250%	$ 225
Supplemental Charges	17,307	4.250%	$ 736

Grand Total

Customer	**$ 412**
Demand	**$ 8,247**
Energy	**$ 6,224**
Riders	**$ 13,011**
Total	**$ 27,895**
$/kWh	**0.06824**

Inputs

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

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

Monthly Billing Units

Total Demand	6,000	kW
Supplmental Demand	2,000	kW
Baseload Demand	4,000	kW
Load Factor	80.00	%
Supplemental Load Factor	40.00	%
Monthly Energy	3,504,000	kWh
Supplemental Energy	584,000	kWh
Baseload Energy	2,336,000	kWh
Backup Energy	292,000	kWh
Maintenance Outage Energy	292,000	kWh
Backup Duration	4	Days
Maintenance Duration	4	Days

Large General Service at Primary Voltage
Summer Period

Reservation Charges

Total Reservation Charges		
Customer	$	412
Demand	$	7,643
Energy	$	-
Riders	$	(62)
Total Cost	$	7,993

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Customer	1	$ 412.37	$ 412	1	$ 412.37	$ 412
Demand	4,000	$ 2.79	$ 11,160	3,960	$ 1.93	$ 7,643
Energy	2,336,000	$ -	$ -	2,312,640	$ -	$ -
Riders						
Capacity Acquisition Rider	8,055	-0.7656%	$ (62)			

Maintenance Charges

Total Maintenance Charges		
Demand	$	1,571
Energy	$	6,250
Riders	$	7,987
Total Cost	$	15,808
$/kWh	$	0.05414

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	16,000	$ 0.1275	$ 2,040	15,840	$ 0.10	$ 1,571
Energy	292,000	$ 0.02162	$ 6,313	289,080	$ 0.02162	$ 6,250
Riders						
Energy Cost Recovery Rider ($/kWh)	292,000	$ 0.01783	$ 5,206	289,080	$ 0.01783	$ 5,154
Energy Efficiency Cost Rate Rider ($/kWh)	292,000	$ 0.00178	$ 520	289,080	$ 0.00178	$ 515
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	4,000	$ -	$ -	3,960	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	292,000	$ 0.00005	$ 15	289,080	$ 0.00005	$ 14
Production Cost Allocation Rider ($/kWh)	292,000	$ 0.00566	$ 1,653	289,080	$ 0.00566	$ 1,636
Capacity Acquisition Rider	8,554	-0.7656%	$ (65)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000	$ 0.18505	$ 740	3,960	$ 0.1851	$ 733

Backup Charges

Total Backup Charges		
Demand	$	4,256
Energy	$	6,250
Riders	$	7,966
Total Cost	$	18,472
$/kWh	$	0.06326

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	16,000	$ 0.297	$ 4,752	15,840	$ 0.27	$ 4,256
Energy	292,000	$ 0.02162	$ 6,313	289,080	$ 0.02162	$ 6,250
Riders						
Energy Cost Recovery Rider ($/kWh)	292,000	$ 0.01783	$ 5,206	289,080	$ 0.01783	$ 5,154
Energy Efficiency Cost Rate Rider ($/kWh)	292,000	$ 0.00178	$ 520	289,080	$ 0.00178	$ 515
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	4,000	$ -	$ -	3,960	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	292,000	$ 0.00005	$ 15	289,080	$ 0.00005	$ 14
Production Cost Allocation Rider ($/kWh)	292,000	$ 0.00566	$ 1,653	289,080	$ 0.00566	$ 1,636
Capacity Acquisition Rider	11,239	-0.7656%	$ (86)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000	$ 0.18505	$ 740	3,960	$ 0.1851	$ 733

Supplemental Charges

Total Supplemental Charges		
Demand	$	16,830
Energy	$	12,500
Riders	$	22,903
Total Cost	$	52,233
$/kWh	$	0.08944

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	2,000	$ 9.36	$ 18,720	1,980	$ 8.50	$ 16,830
Energy	584,000	$ 0.02162	$ 12,626	578,160	$ 0.02162	$ 12,500
Riders						
Energy Cost Recovery Rider ($/kWh)	584,000	$ 0.01783	$ 10,413	578,160	$ 0.01783	$ 10,309
Energy Efficiency Cost Rate Rider ($/kWh)	584,000	$ 0.00178	$ 1,040	578,160	$ 0.00178	$ 1,029
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	4,000	$ 1.96	$ 7,840	3,960	$ 1.96	$ 7,762
Federal Litigation Consulting Fee Rider ($/kWh)	584,000	$ 0.00005	$ 29	578,160	$ 0.00005	$ 29
Production Cost Allocation Rider ($/kWh)	584,000	$ 0.00566	$ 3,305	578,160	$ 0.00566	$ 3,272
Capacity Acquisition Rider	30,063	-0.7656%	$ (230)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000	$ 0.18505	$ 740	3,960	$ 0.1851	$ 733

Municipal Franchise Adjustment Rider

	Units	Rate	Charge
Reservation Charges	7,993	4.250%	$ 340
Maintenance Charges	15,808	4.250%	$ 672
Backup Charges	18,472	4.250%	$ 785
Supplemental Charges	52,233	4.250%	$ 2,220

Grand Total

Customer	**$**	**412**
Demand	**$**	**30,300**
Energy	**$**	**25,000**
Riders	**$**	**42,811**
Total	**$**	**98,524**
$/kWh		**0.08435**

Inputs

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

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

Monthly Billing Units

Total Demand	6,000	kW
Supplmental Demand	2,000	kW
Baseload Demand	4,000	kW
Load Factor	80.00	%
Supplemental Load Factor	40.00	%
Monthly Energy	3,504,000	kWh
Supplemental Energy	584,000	kWh
Baseload Energy	2,336,000	kWh
Backup Energy	292,000	kWh
Maintenance Outage Energy	292,000	kWh
Backup Duration	4	Days
Maintenance Duration	4	Days

Large General Service at Primary Voltage

Other Period

Reservation Charges

Total Reservation Charges	
Customer	$ 412
Demand	$ 7,643
Energy	$ -
Riders	$ (62)
Total Cost	$ 7,993

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Customer	1	$ 412.37	$ 412	1	$ 412.37	$ 412
Demand	4,000	$ 2.79	$ 11,160	3,960	$ 1.93	$ 7,643
Energy	2,336,000	$ -	$ -	2,312,640	$ -	$ -
Riders						
Capacity Acquisition Rider	8,055	-0.7656%	$ (62)			

Maintenance Charges

Total Maintenance Charges	
Demand	$ 1,315
Energy	$ 4,446
Riders	$ 8,003
Total Cost	$ 13,763
$/kWh	$ 0.04713

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	16,000	$ 0.1113	$ 1,781	15,840	$ 0.08	$ 1,315
Energy	292,000	$ 0.01538	$ 4,491	289,080	$ 0.01538	$ 4,446
Riders						
Energy Cost Recovery Rider ($/kWh)	292,000	$ 0.01783	$ 5,206	289,080	$ 0.01783	$ 5,154
Energy Efficiency Cost Rate Rider ($/kWh)	292,000	$ 0.00178	$ 520	289,080	$ 0.00178	$ 515
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	4,000	$ -	$ -	3,960	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	292,000	$ 0.00005	$ 15	289,080	$ 0.00005	$ 14
Production Cost Allocation Rider ($/kWh)	292,000	$ 0.00566	$ 1,653	289,080	$ 0.00566	$ 1,636
Capacity Acquisition Rider	6,494	-0.7656%	$ (50)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000	$ 0.18505	$ 740	3,960	$ 0.1851	$ 733

Backup Charges

Total Backup Charges	
Demand	$ 3,528
Energy	$ 4,446
Riders	$ 7,986
Total Cost	$ 15,959
$/kWh	$ 0.05466

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	16,000	$ 0.251	$ 4,016	15,840	$ 0.22	$ 3,528
Energy	292,000	$ 0.01538	$ 4,491	289,080	$ 0.01538	$ 4,446
Riders						
Energy Cost Recovery Rider ($/kWh)	292,000	$ 0.01783	$ 5,206	289,080	$ 0.01783	$ 5,154
Energy Efficiency Cost Rate Rider ($/kWh)	292,000	$ 0.00178	$ 520	289,080	$ 0.00178	$ 515
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	4,000	$ -	$ -	3,960	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	292,000	$ 0.00005	$ 15	289,080	$ 0.00005	$ 14
Production Cost Allocation Rider ($/kWh)	292,000	$ 0.00566	$ 1,653	289,080	$ 0.00566	$ 1,636
Capacity Acquisition Rider	8,706	-0.7656%	$ (67)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000	$ 0.18505	$ 740	3,960	$ 0.1851	$ 733

Supplemental Charges

Total Supplemental Charges	
Demand	$ 13,999
Energy	$ 8,892
Riders	$ 22,953
Total Cost	$ 45,843
$/kWh	$ 0.07850

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	2,000	$ 7.93	$ 15,860	1,980	$ 7.07	$ 13,999
Energy	584,000	$ 0.01538	$ 8,982	578,160	$ 0.01538	$ 8,892
Riders						
Energy Cost Recovery Rider ($/kWh)	584,000	$ 0.01783	$ 10,413	578,160	$ 0.01783	$ 10,309
Energy Efficiency Cost Rate Rider ($/kWh)	584,000	$ 0.00178	$ 1,040	578,160	$ 0.00178	$ 1,029
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	4,000	$ 1.96	$ 7,840	3,960	$ 1.96	$ 7,762
Federal Litigation Consulting Fee Rider ($/kWh)	584,000	$ 0.00005	$ 29	578,160	$ 0.00005	$ 29
Production Cost Allocation Rider ($/kWh)	584,000	$ 0.00566	$ 3,305	578,160	$ 0.00566	$ 3,272
Capacity Acquisition Rider	23,623	-0.7656%	$ (181)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	4,000	$ 0.18505	$ 740	3,960	$ 0.1851	$ 733

Municipal Franchise Adjustment Rider

	Units	Rate	Charge
Reservation Charges	7,993	4.250%	$ 340
Maintenance Charges	13,763	4.250%	$ 585
Backup Charges	15,959	4.250%	$ 678
Supplemental Charges	45,843	4.250%	$ 1,948

Grand Total

Customer	**$ 412**
Demand	**$ 26,484**
Energy	**$ 17,784**
Riders	**$ 42,430**
Total	**$ 87,111**
$/kWh	**0.07458**

Inputs

	Season	
Select Season From Drop Down	Summer Period	
	Load Characteristics	
Enter Peak Demand (kW)	30,000	kW
Enter Load Factor	75	%
	Generator Characteristics	
Enter Net Capability (kW)	20,000	kW
Enter Backup Hours	40	Hours
Enter Maintenace Hours	40	Hours

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

Monthly Billing Units

Total Demand	30,000	kW
Supplmental Demand	10,000	kW
Baseload Demand	20,000	kW
Load Factor	75.00	%
Supplemental Load Factor	25.00	%
Monthly Energy	16,425,000	kWh
Supplemental Energy	1,825,000	kWh
Baseload Energy	13,000,000	kWh
Backup Energy	800,000	kWh
Maintenance Outage Energy	800,000	kWh
Backup Duration	2	Days
Maintenance Duration	2	Days

Large Power Service at Transmission Voltage
Summer Period

Reservation Charges

Total Reservation Charges	
Customer	$ 412
Demand	$ 19,012
Energy	$ -
Riders	$ (149)
Total Cost	$ 19,276

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Customer	1	$ 412.37	$ 412	1	$ 412.37	$ 412
Demand	20,000	$ 2.79	$ 55,800	19,600	$ 0.97	$ 19,012
Energy	13,000,000	$ -	$ -	12,740,000	$ -	$ -
Riders						
Capacity Acquisition Rider	19,424	-0.7656%	$ (149)			

Maintenance Charges

Total Maintenance Charges	
Demand	$ 2,654
Energy	$ 16,950
Riders	$ 23,300
Total Cost	$ 42,904
$/kWh	$ 0.05363

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	40,000	$ 0.12750	$ 5,100	39,200	$ 0.06770	$ 2,654
Energy	800,000	$ 0.02162	$ 17,296	784,000	$ 0.02162	$ 16,950
Riders						
Energy Cost Recovery Rider ($/kWh)	800,000	$ 0.01783	$ 14,264	784,000	$ 0.01783	$ 13,979
Energy Efficiency Cost Rate Rider ($/kWh)	800,000	$ 0.00178	$ 1,424	784,000	$ 0.00178	$ 1,396
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000	$ -	$ -	19,600	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	800,000	$ 0.00005	$ 40	784,000	$ 0.00005	$ 39
Production Cost Allocation Rider ($/kWh)	800,000	$ 0.00566	$ 4,528	784,000	$ 0.00566	$ 4,437
Capacity Acquisition Rider	23,231	-0.7656%	$ (178)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000	$ 0.1851	$ 3,701	19,600	$ 0.1851	$ 3,627

Backup Charges

Total Backup Charges	
Demand	$ 9,298
Energy	$ 16,950
Riders	$ 23,249
Total Cost	$ 49,497
$/kWh	$ 0.06187

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	40,000	$ 0.297	$ 11,880	39,200	$ 0.24	$ 9,298
Energy	800,000	$ 0.02162	$ 17,296	784,000	$ 0.02162	$ 16,950
Riders						
Energy Cost Recovery Rider ($/kWh)	800,000	$ 0.01783	$ 14,264	784,000	$ 0.01783	$ 13,979
Energy Efficiency Cost Rate Rider ($/kWh)	800,000	$ 0.00178	$ 1,424	784,000	$ 0.00178	$ 1,396
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000	$ -	$ -	19,600	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	800,000	$ 0.00005	$ 40	784,000	$ 0.00005	$ 39
Production Cost Allocation Rider ($/kWh)	800,000	$ 0.00566	$ 4,528	784,000	$ 0.00566	$ 4,437
Capacity Acquisition Rider	29,875	-0.7656%	$ (229)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000	$ 0.1851	$ 3,701	19,600	$ 0.1851	$ 3,627

Supplemental Charges

Total Supplemental Charges	
Demand	$ 70,952
Energy	$ 38,667
Riders	$ 86,461
Total Cost	$ 196,080
$/kWh	$ 0.10744

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	10,000	$ 9.0600	$ 90,600	9,800	$ 7.2400	$ 70,952
Energy	1,825,000	$ 0.02162	$ 39,457	1,788,500	$ 0.02162	$ 38,667
Riders						
Energy Cost Recovery Rider ($/kWh)	1,825,000	$ 0.01783	$ 32,540	1,788,500	$ 0.01783	$ 31,889
Energy Efficiency Cost Rate Rider ($/kWh)	1,825,000	$ 0.00178	$ 3,249	1,788,500	$ 0.00178	$ 3,184
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000	$ 1.96	$ 39,200	19,600	$ 1.96	$ 38,416
Federal Litigation Consulting Fee Rider ($/kWh)	1,825,000	$ 0.00005	$ 91	1,788,500	$ 0.00005	$ 89
Production Cost Allocation Rider ($/kWh)	1,825,000	$ 0.00566	$ 10,330	1,788,500	$ 0.00566	$ 10,123
Capacity Acquisition Rider	113,246	-0.7656%	$ (867)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000	$ 0.1851	$ 3,701	19,600	$ 0.1851	$ 3,627

Municipal Franchise Adjustment Rider

	Units	Rate	Charge
Reservation Charges	19,276	4.250%	$ 819
Maintenance Charges	42,904	4.250%	$ 1,823
Backup Charges	49,497	4.250%	$ 2,104
Supplemental Charges	196,080	4.250%	$ 8,333

Grand Total

Customer	**$ 412**
Demand	**$ 101,916**
Energy	**$ 72,568**
Riders	**$ 145,941**
Total	**$ 320,837**
$/kWh	**0.09367**

Inputs

	Season	
Select Season From Drop Down	Other Period	
	Load Characteristics	
Enter Peak Demand (kW)	30,000	kW
Enter Load Factor	75	%
	Generator Characteristics	
Enter Net Capability (kW)	20,000	kW
Enter Backup Hours	40	Hours
Enter Maintenace Hours	40	Hours

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

Monthly Billing Units

Total Demand	30,000	kW
Supplmental Demand	10,000	kW
Baseload Demand	20,000	kW
Load Factor	75.00	%
Supplemental Load Factor	25.00	%
Monthly Energy	16,425,000	kWh
Supplemental Energy	1,825,000	kWh
Baseload Energy	13,000,000	kWh
Backup Energy	800,000	kWh
Maintenance Outage Energy	800,000	kWh
Backup Duration	2	Days
Maintenance Duration	2	Days

Large Power Service at Transmission Voltage

Other Period

Reservation Charges

Total Reservation Charges	
Customer	$ 412
Demand	$ 19,012
Energy	$ -
Riders	$ (149)
Total Cost	$ 19,276

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Customer	1	$ 412.37	$ 412	1	$ 412.37	$ 412
Demand	20,000	$ 2.79	$ 55,800	19,600	$ 0.97	$ 19,012
Energy	13,000,000	$ -	$ -	12,740,000	$ -	$ -
Riders						
Capacity Acquisition Rider	19,424	-0.7656%	$ (149)			

Maintenance Charges

Total Maintenance Charges	
Demand	$ 2,019
Energy	$ 12,058
Riders	$ 23,342
Total Cost	$ 37,419
$/kWh	$ 0.04677

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	40,000	$ 0.11130	$ 4,452	39,200	$ 0.05150	$ 2,019
Energy	800,000	$ 0.01538	$ 12,304	784,000	$ 0.01538	$ 12,058
Riders						
Energy Cost Recovery Rider ($/kWh)	800,000	$ 0.01783	$ 14,264	784,000	$ 0.01783	$ 13,979
Energy Efficiency Cost Rate Rider ($/kWh)	800,000	$ 0.00178	$ 1,424	784,000	$ 0.00178	$ 1,396
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000	$ -	$ -	19,600	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	800,000	$ 0.00005	$ 40	784,000	$ 0.00005	$ 39
Production Cost Allocation Rider ($/kWh)	800,000	$ 0.00566	$ 4,528	784,000	$ 0.00566	$ 4,437
Capacity Acquisition Rider	17,704	-0.7656%	$ (136)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000	$ 0.1851	$ 3,701	19,600	$ 0.1851	$ 3,627

Backup Charges

Total Backup Charges	
Demand	$ 7,495
Energy	$ 12,058
Riders	$ 23,300
Total Cost	$ 42,853
$/kWh	$ 0.05357

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	40,000	$ 0.251	$ 10,040	39,200	$ 0.19	$ 7,495
Energy	800,000	$ 0.01538	$ 12,304	784,000	$ 0.01538	$ 12,058
Riders						
Energy Cost Recovery Rider ($/kWh)	800,000	$ 0.01783	$ 14,264	784,000	$ 0.01783	$ 13,979
Energy Efficiency Cost Rate Rider ($/kWh)	800,000	$ 0.00178	$ 1,424	784,000	$ 0.00178	$ 1,396
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000	$ -	$ -	19,600	$ -	$ -
Federal Litigation Consulting Fee Rider ($/kWh)	800,000	$ 0.00005	$ 40	784,000	$ 0.00005	$ 39
Production Cost Allocation Rider ($/kWh)	800,000	$ 0.00566	$ 4,528	784,000	$ 0.00566	$ 4,437
Capacity Acquisition Rider	23,180	-0.7656%	$ (177)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000	$ 0.1851	$ 3,701	19,600	$ 0.1851	$ 3,627

Supplemental Charges

Total Supplemental Charges	
Demand	$ 56,840
Energy	$ 27,507
Riders	$ 86,654
Total Cost	$ 171,001
$/kWh	$ 0.09370

	Units	Rate	Charge	Volt. Adj. Reduced Units	Volt. Adj. Reduced Rate	Volt. Adj. Reduced Charge
Base Charges						
Demand	10,000	$ 7.6200	$ 76,200	9,800	$ 5.8000	$ 56,840
Energy	1,825,000	$ 0.01538	$ 28,069	1,788,500	$ 0.01538	$ 27,507
Riders						
Energy Cost Recovery Rider ($/kWh)	1,825,000	$ 0.01783	$ 32,540	1,788,500	$ 0.01783	$ 31,889
Energy Efficiency Cost Rate Rider ($/kWh)	1,825,000	$ 0.00178	$ 3,249	1,788,500	$ 0.00178	$ 3,184
Grand Gulf Rider (SGS energy, LGS & LPS Demand)	20,000	$ 1.96	$ 39,200	19,600	$ 1.96	$ 38,416
Federal Litigation Consulting Fee Rider ($/kWh)	1,825,000	$ 0.00005	$ 91	1,788,500	$ 0.00005	$ 89
Production Cost Allocation Rider ($/kWh)	1,825,000	$ 0.00566	$ 10,330	1,788,500	$ 0.00566	$ 10,123
Capacity Acquisition Rider	87,974	-0.7656%	$ (674)			
Storm Recovery Rider (SGS Energy, LGS &LPS Demand)	20,000	$ 0.1851	$ 3,701	19,600	$ 0.1851	$ 3,627

Municipal Franchise Adjustment Rider

	Units	Rate	Charge
Reservation Charges	19,276	4.250%	$ 819
Maintenance Charges	37,419	4.250%	$ 1,590
Backup Charges	42,853	4.250%	$ 1,821
Supplemental Charges	171,001	4.250%	$ 7,268

Grand Total

Customer	**$ 412**
Demand	**$ 85,366**
Energy	**$ 51,623**
Riders	**$ 144,647**
Total	**$ 282,048**
$/kWh	**0.08235**

Entergy Arkansas Inc. - Standby Service Rider (SSR)

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

Line	Voltage Level	Current $/kW	Revised $/kW
1	Primary	$1.93	$1.14
2	Transmission	$0.97	$0.37

	Scenerios	Self Gen kW	Voltage	Monthly Current Cost	Monthly Revised Cost	Monthly 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.

	Voltage Level	Current Summer Backup Charge $/kW/Day	Current Other Backup Charge $/kW/Day	Estimated On-Peak Summer Backup Charge $/kW/Day	Estimated On-Peak Other Backup Charge $/kW/Day
6	Primary	$0.266	$0.220	$0.401	$0.333
7	Transmission	$0.232	$0.187	$0.352	$0.285

	Voltage Level	Current Summer Maintenance Charge $/kW/Day	Current Other Maintenance Charge $/kW/Day	Estimated On-Peak Summer Maintenance Charge $/kW/Day	Estimated On-Peak Other Maintenance Charge $/kW/Day
8	Primary	$0.098	$0.082	$0.148	$0.124
9	Transmission	$0.066	$0.050	$0.100	$0.077

Savings Analysis For Summer Period

	Scenerios	Self Gen kW	Voltage	Backup Days	Summer Monthly Backup Savings	Summer Monthly Maintenance Savings
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 Days	Summer Monthly Backup Costs	Summer Monthly Maintenance Costs
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.
3. Savings occur when backup is needed during off peak periods such as weekends.
4. Costs occur when backup is needed during on peak periods.

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 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.

Tabs

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.

- 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.

Inputs

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

Monthly Billing Units

Total Load	1,500	kW
Supplemental Demand	800	kW
Contracted Standby Capacity	700	kW
Load Factor	70.00	%
Supplemental Load Factor	43.75	%
Total Energy	766,500	kWh
Supplemental Energy	255,500	kWh
On-Site Generated Energy	483,000	kWh
Usage Energy	28,000	kWh

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

Primary
Summer Season

Reservation Charges

Total Reservation Charges		
Customer	$	305
Demand	$	1,078
Riders	$	404
Total Cost	$	1,787

	Units	Rate		Charge	
Base Charges					
Service and Facilities Charge	1	$	305.00	$	305
Interconnection Charge	1	$	-	$	-
Distribution Demand Charge ($/kW)	700	$	3.98		
Generation and Transmission Demand Charge ($/kW)	700	$	1.54	$	1,078
Riders					
General Rate Schedule Adjustment (GRSA)	1,383		14.05%	$	194
Demand-Side Management Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	700	$	0.04	$	28
Purchased Capacity Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	700	$	0.26	$	182
Transmission Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	700	$	-	$	-
Electric Commodity Adjustment ($/kWh)	-	$	0.02955	$	-

Usage Charges

Total Usage Charges		
Demand	$	-
Energy	$	129
Riders	$	2,435
Total Cost	$	2,564
$/kWh	$	0.09156

	Units	Rate		Charge	
Base Charges					
Demand Charge ($/kW)	-	$	11.31	$	-
Energy Charge ($/kWh)	28,000	$	0.00461	$	129
Riders					
General Rate Schedule Adjustment (GRSA)	129		14.05%	$	18
Demand-Side Management Cost Adjustment - Standby Service - Usage ($/kW-Mo)	700	$	0.37	$	259
Purchased Capacity Cost Adjustment - Standby Service - Usage ($/kW-Mo)	700	$	1.89	$	1,323
Transmission Cost Adjustment - Standby Service - Usage ($/kW-Mo)	700	$	0.01	$	7
Electric Commodity Adjustment ($/kWh)	28,000	$	0.02955		827

Supplemental Charges

Total Supplemental Charges		
Customer	$	305
Demand	$	11,216
Energy	$	1,178
Riders	$	11,390
Total Cost	$	23,784
$/kWh	$	0.09309

	Units	Rate		Charge	
Base Charges					
Service and Facilities Charge	1	$	305.00	$	305
Distribution Demand Charge ($/kW)	800	$	3.98	$	3,184
Generation and Transmission Demand Charge ($/kW)	800	$	10.04	$	8,032
Energy Charge ($/kWh)	255,500	$	0.00461	$	1,178
Riders					
General Rate Schedule Adjustment (GRSA)	12,699		14.05%	$	1,784
Demand-Side Management Cost Adjustment - General Service ($/kW-Mo)	800	$	0.41	$	328
Purchased Capacity Cost Adjustment - General Service ($/kW-Mo)	800	$	2.15	$	1,720
Transmission Cost Adjustment - General Service ($/kW-Mo)	800	$	0.01	$	8
Electric Commodity Adjustment ($/kWh)	255,500	$	0.02955	$	7,550

Renewable Energy Standard Adjustment

	Units	Rate	Charge	
Reservation Charges	1,787	2.00%	$	36
Usage Charges	2,564	2.00%	$	51
Supplemental Charges	23,784	2.00%	$	476

Grand Total

Customer	**$**	**610**
Demand	**$**	**12,294**
Energy	**$**	**1,711**
Riders	**$**	**16,175**
Total	**$**	**30,790**
$/kWh		**0.10861**

Primary
Winter Season

Reservation Charges

Total Reservation Charges	
Customer	$ 305
Demand	$ 511
Riders	$ 325
Total Cost	$ 1,141

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 305.00	$ 305
Interconnection Charge	1	$ -	$ -
Distribution Demand Charge ($/kW)	700	$ 3.98	
Generation and Transmission Demand Charge ($/kW)	700	$ 0.73	$ 511
Riders			
General Rate Schedule Adjustment (GRSA)	816	14.05%	$ 115
Demand-Side Management Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	700	$ 0.04	$ 28
Purchased Capacity Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	700	$ 0.26	$ 182
Transmission Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	700	$ -	$ -
Electric Commodity Adjustment ($/kWh)	-	$ 0.02955	$ -

Usage Charges

Total Usage Charges	
Demand	$ -
Energy	$ 129
Riders	$ 2,435
Total Cost	$ 2,564
$/kWh	$ 0.09156

	Units	Rate	Charge
Base Charges			
Demand Charge ($/kW)	-	$ 5.34	$ -
Energy Charge ($/kWh)	28,000	$ 0.00461	$ 129
Riders			
General Rate Schedule Adjustment (GRSA)	129	14.05%	$ 18
Demand-Side Management Cost Adjustment - Standby Service - Usage ($/kW-Mo)	700	$ 0.37	$ 259
Purchased Capacity Cost Adjustment - Standby Service - Usage ($/kW-Mo)	700	$ 1.89	$ 1,323
Transmission Cost Adjustment - Standby Service - Usage ($/kW-Mo)	700	$ 0.01	$ 7
Electric Commodity Adjustment ($/kWh)	28,000	$ 0.02955	827

Supplemental Charges

Total Supplemental Charges	
Customer	$ 305
Demand	$ 8,808
Energy	$ 1,178
Riders	$ 11,052
Total Cost	$ 21,038
$/kWh	$ 0.08234

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 305.00	$ 305
Distribution Demand Charge ($/kW)	800	$ 3.98	$ 3,184
Generation and Transmission Demand Charge ($/kW)	800	$ 7.03	$ 5,624
Energy Charge ($/kWh)	255,500	$ 0.00461	$ 1,178
Riders			
General Rate Schedule Adjustment (GRSA)	10,291	14.05%	$ 1,446
Demand-Side Management Cost Adjustment - General Service ($/kW-Mo)	800	$ 0.41	$ 328
Purchased Capacity Cost Adjustment - General Service ($/kW-Mo)	800	$ 2.15	$ 1,720
Transmission Cost Adjustment - General Service ($/kW-Mo)	800	$ 0.01	$ 8
Electric Commodity Adjustment ($/kWh)	255,500	$ 0.02955	$ 7,550

Renewable Energy Standard Adjustment

	Units	Rate	Charge
Reservation Charges	1,141	2.00%	$ 23
Usage Charges	2,564	2.00%	$ 51
Supplemental Charges	21,038	2.00%	$ 421

Grand Total

Customer	**$ 610**
Demand	**$ 9,319**
Energy	**$ 1,632**
Riders	**$ 15,122**
Total	**$ 26,683**
$/kWh	**0.09412**

Inputs

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

Monthly Billing Units

Total Load	6,000	kW
Supplemental Demand	2,000	kW
Contracted Standby Capacity	4,000	kW
Load Factor	80.00	%
Supplemental Load Factor	40.00	%
Total Energy	3,504,000	kWh
Supplemental Energy	584,000	kWh
On-Site Generated Energy	2,720,000	kWh
Usage Energy	200,000	kWh

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

Primary
Summer Season

Reservation Charges

Total Reservation Charges		
Customer	$	305
Demand	$	6,160
Riders	$	2,108
Total Cost	$	8,573

	Units	Rate		Charge	
Base Charges					
Service and Facilities Charge	1	$	305.00	$	305
Interconnection Charge	1	$	-	$	-
Distribution Demand Charge ($/kW)	4,000	$	3.98		
Generation and Transmission Demand Charge ($/kW)	4,000	$	1.54	$	6,160
Riders					
General Rate Schedule Adjustment (GRSA)	6,465		14.05%	$	908
Demand-Side Management Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	4,000	$	0.04	$	160
Purchased Capacity Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	4,000	$	0.26	$	1,040
Transmission Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	4,000	$	-	$	-
Electric Commodity Adjustment ($/kWh)	-	$	0.02955	$	-

Usage Charges

Total Usage Charges		
Demand	$	-
Energy	$	922
Riders	$	15,120
Total Cost	$	16,042
$/kWh	$	0.08021

	Units	Rate		Charge	
Base Charges					
Demand Charge ($/kW)	-	$	11.31	$	-
Energy Charge ($/kWh)	200,000	$	0.00461	$	922
Riders					
General Rate Schedule Adjustment (GRSA)	922		14.05%	$	130
Demand-Side Management Cost Adjustment - Standby Service - Usage ($/kW-Mo)	4,000	$	0.37	$	1,480
Purchased Capacity Cost Adjustment - Standby Service - Usage ($/kW-Mo)	4,000	$	1.89	$	7,560
Transmission Cost Adjustment - Standby Service - Usage ($/kW-Mo)	4,000	$	0.01	$	40
Electric Commodity Adjustment ($/kWh)	200,000	$	0.02955		5,910

Supplemental Charges

Total Supplemental Charges		
Customer	$	305
Demand	$	28,040
Energy	$	2,692
Riders	$	26,758
Total Cost	$	57,491
$/kWh	$	0.09844

	Units	Rate		Charge	
Base Charges					
Service and Facilities Charge	1	$	305.00	$	305
Distribution Demand Charge ($/kW)	2,000	$	3.98	$	7,960
Generation and Transmission Demand Charge ($/kW)	2,000	$	10.04	$	20,080
Energy Charge ($/kWh)	584,000	$	0.00461	$	2,692
Riders					
General Rate Schedule Adjustment (GRSA)	31,037		14.05%	$	4,361
Demand-Side Management Cost Adjustment - General Service ($/kW-Mo)	2,000	$	0.41	$	820
Purchased Capacity Cost Adjustment - General Service ($/kW-Mo)	2,000	$	2.15	$	4,300
Transmission Cost Adjustment - General Service ($/kW-Mo)	2,000	$	0.01	$	20
Electric Commodity Adjustment ($/kWh)	584,000	$	0.02955	$	17,258

Renewable Energy Standard Adjustment

	Units	Rate	Charge	
Reservation Charges	8,573	2.00%	$	171
Usage Charges	16,042	2.00%	$	321
Supplemental Charges	57,491	2.00%	$	1,150

Grand Total

Customer	$	**610**
Demand	$	**34,200**
Energy	$	**5,723**
Riders	$	**52,094**
Total	$	**92,626**
$/kWh		**0.11815**

Primary
Winter Season

Reservation Charges

Total Reservation Charges	
Customer	$ 305
Demand	$ 2,920
Riders	$ 1,653
Total Cost	$ 4,878

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 305.00	$ 305
Interconnection Charge	1	$ -	$ -
Distribution Demand Charge ($/kW)	4,000	$ 3.98	
Generation and Transmission Demand Charge ($/kW)	4,000	$ 0.73	$ 2,920
Riders			
General Rate Schedule Adjustment (GRSA)	3,225	14.05%	$ 453
Demand-Side Management Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	4,000	$ 0.04	$ 160
Purchased Capacity Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	4,000	$ 0.26	$ 1,040
Transmission Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	4,000	$ -	$ -
Electric Commodity Adjustment ($/kWh)	-	$ 0.02955	$ -

Usage Charges

Total Usage Charges	
Demand	$ -
Energy	$ 922
Riders	$ 15,120
Total Cost	$ 16,042
$/kWh	$ 0.08021

	Units	Rate	Charge
Base Charges			
Demand Charge ($/kW)	-	$ 5.34	$ -
Energy Charge ($/kWh)	200,000	$ 0.00461	$ 922
Riders			
General Rate Schedule Adjustment (GRSA)	922	14.05%	$ 130
Demand-Side Management Cost Adjustment - Standby Service - Usage ($/kW-Mo)	4,000	$ 0.37	$ 1,480
Purchased Capacity Cost Adjustment - Standby Service - Usage ($/kW-Mo)	4,000	$ 1.89	$ 7,560
Transmission Cost Adjustment - Standby Service - Usage ($/kW-Mo)	4,000	$ 0.01	$ 40
Electric Commodity Adjustment ($/kWh)	200,000	$ 0.02955	5,910

Supplemental Charges

Total Supplemental Charges	
Customer	$ 305
Demand	$ 22,020
Energy	$ 2,692
Riders	$ 25,913
Total Cost	$ 50,625
$/kWh	$ 0.08669

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 305.00	$ 305
Distribution Demand Charge ($/kW)	2,000	$ 3.98	$ 7,960
Generation and Transmission Demand Charge ($/kW)	2,000	$ 7.03	$ 14,060
Energy Charge ($/kWh)	584,000	$ 0.00461	$ 2,692
Riders			
General Rate Schedule Adjustment (GRSA)	25,017	14.05%	$ 3,515
Demand-Side Management Cost Adjustment - General Service ($/kW-Mo)	2,000	$ 0.41	$ 820
Purchased Capacity Cost Adjustment - General Service ($/kW-Mo)	2,000	$ 2.15	$ 4,300
Transmission Cost Adjustment - General Service ($/kW-Mo)	2,000	$ 0.01	$ 20
Electric Commodity Adjustment ($/kWh)	584,000	$ 0.02955	$ 17,258

Renewable Energy Standard Adjustment

	Units	Rate	Charge
Reservation Charges	4,878	2.00%	$ 98
Usage Charges	16,042	2.00%	$ 321
Supplemental Charges	50,625	2.00%	$ 1,012

Grand Total

Customer	**$ 610**
Demand	**$ 24,940**
Energy	**$ 5,267**
Riders	**$ 47,341**
Total	**$ 78,159**
$/kWh	**0.09969**

Inputs

Season

Select Season From Drop Down	Winter Season	

Load Characteristics

Enter Peak Demand (kW)	30,000	kW
Enter Load Factor	75	%

Generator Characteristics

Enter Net Capability (kW)	20,000	kW
Enter Generator Outage Hours	40	Hours

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

Monthly Billing Units

Total Load	30,000	kW
Supplemental Demand	10,000	kW
Contracted Standby Capacity	20,000	kW
Load Factor	75.00	%
Supplemental Load Factor	25.00	%
Total Energy	16,425,000	kWh
Supplemental Energy	1,825,000	kWh
On-Site Generated Energy	13,800,000	kWh
Usage Energy	800,000	kWh

Transmission
Summer Season

Reservation Charges

Total Reservation Charges	
Customer	$ 1,450
Demand	$ 28,400
Riders	$ 9,794
Total Cost	$ 39,644

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 450.00	$ 450
Interconnection Charge	1	$ 1,000.00	$ 1,000
Distribution Demand Charge ($/kW)	20,000	$ -	
Generation and Transmission Demand Charge ($/kW)	20,000	$ 1.42	$ 28,400
Riders			
General Rate Schedule Adjustment (GRSA)	29,850	14.05%	$ 4,194
Demand-Side Management Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	20,000	$ 0.04	$ 800
Purchased Capacity Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	20,000	$ 0.24	$ 4,800
Transmission Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	20,000	$ -	$ -
Electric Commodity Adjustment ($/kWh)	-	$ 0.02930	$ -

Usage Charges

Total Usage Charges	
Demand	$ -
Energy	$ 3,608
Riders	$ 66,545
Total Cost	$ 70,153
$/kWh	$ 0.08769

	Units	Rate	Charge
Base Charges			
Demand Charge ($/kW)	-	$ 10.43	$ -
Energy Charge ($/kWh)	800,000	$ 0.00451	$ 3,608
Riders			
General Rate Schedule Adjustment (GRSA)	3,608	14.05%	$ 507
Demand-Side Management Cost Adjustment - Standby Service - Usage ($/kW-Mo)	20,000	$ 0.34	$ 6,800
Purchased Capacity Cost Adjustment - Standby Service - Usage ($/kW-Mo)	20,000	$ 1.78	$ 35,600
Transmission Cost Adjustment - Standby Service - Usage ($/kW-Mo)	20,000	$ 0.01	$ 200
Electric Commodity Adjustment ($/kWh)	800,000	$ 0.02930	23,438

Supplemental Charges

Total Supplemental Charges	
Customer	$ 1,000
Demand	$ 96,800
Energy	$ 8,231
Riders	$ 92,465
Total Cost	$ 197,496
$/kWh	$ 0.10822

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 1,000.00	$ 1,000
Distribution Demand Charge ($/kW)	10,000	$ -	$ -
Generation and Transmission Demand Charge ($/kW)	10,000	$ 9.68	$ 96,800
Energy Charge ($/kWh)	1,825,000	$ 0.00451	$ 8,231
Riders			
General Rate Schedule Adjustment (GRSA)	106,031	14.05%	$ 14,897
Demand-Side Management Cost Adjustment - General Service ($/kW-Mo)	10,000	$ 0.38	$ 3,800
Purchased Capacity Cost Adjustment - General Service ($/kW-Mo)	10,000	$ 2.02	$ 20,200
Transmission Cost Adjustment - General Service ($/kW-Mo)	10,000	$ 0.01	$ 100
Electric Commodity Adjustment ($/kWh)	1,825,000	$ 0.02930	$ 53,468

Renewable Energy Standard Adjustment

	Units	Rate	Charge
Reservation Charges	39,644	2.00%	$ 793
Usage Charges	70,153	2.00%	$ 1,403
Supplemental Charges	197,496	2.00%	$ 3,950

Grand Total

Customer	**$ 2,450**
Demand	**$ 125,200**
Energy	**$ 21,633**
Riders	**$ 204,800**
Total	**$ 354,083**
$/kWh	**0.13489**

Transmission
Winter Season

Reservation Charges

Total Reservation Charges	
Customer	$ 1,450
Demand	$ 13,200
Riders	$ 7,658
Total Cost	$ 22,308

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 450.00	$ 450
Interconnection Charge	1	$ 1,000.00	$ 1,000
Distribution Demand Charge ($/kW)	20,000	$ -	
Generation and Transmission Demand Charge ($/kW)	20,000	$ 0.66	$ 13,200
Riders			
General Rate Schedule Adjustment (GRSA)	14,650	14.05%	$ 2,058
Demand-Side Management Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	20,000	$ 0.04	$ 800
Purchased Capacity Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	20,000	$ 0.24	$ 4,800
Transmission Cost Adjustment - Standby Service - Reservation ($/kW-Mo)	20,000	$ -	$ -
Electric Commodity Adjustment ($/kWh)	-	$ 0.02930	$ -

Usage Charges

Total Usage Charges	
Demand	$ -
Energy	$ 3,608
Riders	$ 66,545
Total Cost	$ 70,153
$/kWh	$ 0.08769

	Units	Rate	Charge
Base Charges			
Demand Charge ($/kW)	-	$ 4.87	$ -
Energy Charge ($/kWh)	800,000	$ 0.00451	$ 3,608
Riders			
General Rate Schedule Adjustment (GRSA)	3,608	14.05%	$ 507
Demand-Side Management Cost Adjustment - Standby Service - Usage ($/kW-Mo)	20,000	$ 0.34	$ 6,800
Purchased Capacity Cost Adjustment - Standby Service - Usage ($/kW-Mo)	20,000	$ 1.78	$ 35,600
Transmission Cost Adjustment - Standby Service - Usage ($/kW-Mo)	20,000	$ 0.01	$ 200
Electric Commodity Adjustment ($/kWh)	800,000	$ 0.02930	23,438

Supplemental Charges

Total Supplemental Charges	
Customer	$ 1,000
Demand	$ 66,800
Energy	$ 8,231
Riders	$ 88,250
Total Cost	$ 163,281
$/kWh	$ 0.08947

	Units	Rate	Charge
Base Charges			
Service and Facilities Charge	1	$ 1,000.00	$ 1,000
Distribution Demand Charge ($/kW)	10,000	$ -	$ -
Generation and Transmission Demand Charge ($/kW)	10,000	$ 6.68	$ 66,800
Energy Charge ($/kWh)	1,825,000	$ 0.00451	$ 8,231
Riders			
General Rate Schedule Adjustment (GRSA)	76,031	14.05%	$ 10,682
Demand-Side Management Cost Adjustment - General Service ($/kW-Mo)	10,000	$ 0.38	$ 3,800
Purchased Capacity Cost Adjustment - General Service ($/kW-Mo)	10,000	$ 2.02	$ 20,200
Transmission Cost Adjustment - General Service ($/kW-Mo)	10,000	$ 0.01	$ 100
Electric Commodity Adjustment ($/kWh)	1,825,000	$ 0.02930	$ 53,468

Renewable Energy Standard Adjustment

	Units	Rate	Charge
Reservation Charges	22,308	2.00%	$ 446
Usage Charges	70,153	2.00%	$ 1,403
Supplemental Charges	163,281	2.00%	$ 3,266

Grand Total

Customer	**$ 2,450**
Demand	**$ 80,000**
Energy	**$ 19,497**
Riders	**$ 182,219**
Total	**$ 284,166**
$/kWh	**0.10825**

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.

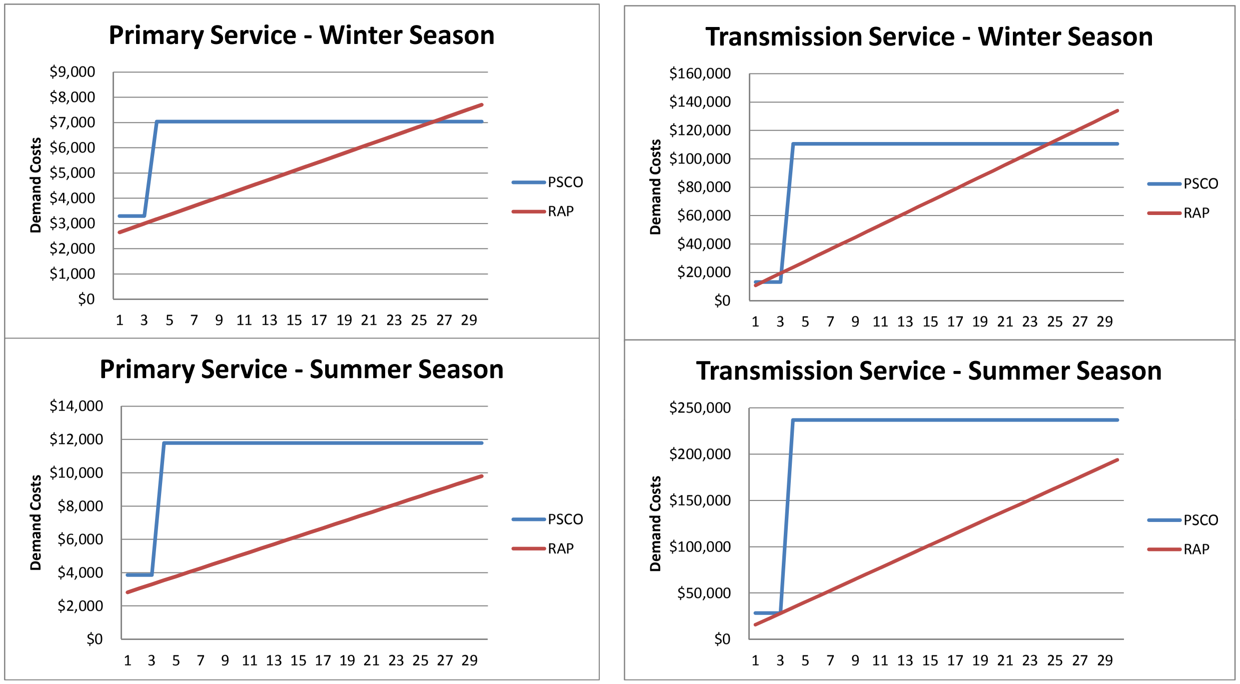
- For this comparison, the peak demand and the capability of on-site generators are set equal to one another. This ensures that there are no demand charges for supplemental power. The primary customer was assumed to be 700 kW, and the transmission customer was assumed to be 20,000 kW.

- The x-axis represents the duration in days of the generator outage from 1 to 30 days. The y-axis 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.

PSCo Standby Costs Compared with Costs Associated with Suggested Revision



Assumptions:
Peak Demand = 700kW
Load Factor = 100%
Gen Capability = 700kW

Assumptions:
Peak Demand = 20,000kW
Load Factor = 100%
Gen Capability = 20,000kW

Public Service Company of Colorado

Primary (PST) & Transmission (TST) Standby Service Rates

Voltage Level	Current Summer Reservation Charge $/kW/Day	Current Winter Reservation Charge $/kW/Day	Revised Summer Reservation Charge $/kW/Day	Revised Winter Reservation Charge $/kW/Day
Primary	$5.520	$4.710	$3.686	$3.536
Trans	$1.420	$0.660	$0.484	$0.334

Primary Rate PG & Transmission Rate TG

G&T Voltage Level	Summer Demand Charge $/kW/Mo	Winter Demand Charge $/kW/Mo	Summer Demand Charge $/kW/Day	Winter Demand Charge $/kW/Day
Primary	$10.04	$7.03	$0.344	$0.249
Trans	$9.68	$6.68	$0.307	$0.212

Dist	Demand Charge $/kW/Mo	Dedicated Charge $/kW/Mo	Demand Charge $/kW/Day
Primary	$3.980	$3.184	$0.027
Trans	$0.000	$0.000	$0.000

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.

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.

Inputs

Season

Select Season From Drop Down	June through September	

Load Characteristics

Enter Peak Demand (kW)	1,500	kW
Enter Load Factor	70	%

Generator Characteristics

Enter Nameplate Capacity (kW)	700	kW
Enter Generator Availability	90	%
Enter Generator Maintenance Hours	50	Hours

Note: Outage Hours must be less than 730.

Monthly Billing Units

Facility Peak Demand	1,500	kW
Supplemental Demand	800	kW
Standby Demand	700	kW
Total Energy	766,500	kWh
On-Site Generated Energy	476,000	kWh
Delivered Energy	290,500	kWh

Standby Service Tariff Units

BD	870	kW
MM	1,500	kW
AG	630	kW
CR	700	kW
CD	700	kW
GA	90%	
SM	50	Hours

Jersey Central Power & Light Company Standby Rates			
June through September	Voltage 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
Riders			
Non-Utility Generation Charge (Rider NGC) ($/kWh)	$ 0.002941	$ 0.002885	$ 0.002826
Transitional Energy Facility Assessment Charge (Rider TEFA) ($/kWh)	$ 0.001312	$ 0.001029	$ 0.001029
Societal Benefits Charge (Rider SBC) ($/kWh)	$ 0.006817	$ 0.006817	$ 0.006817
Rider CIEP - Standby Fee ($/kWh)	$ 0.000150	$ 0.000150	$ 0.000150
System Control Charge (Rider SCC) ($/kWh)	$ 0.000055	$ 0.000055	$ 0.000055
RGGI Revovery Charge (Rider RRC) ($/kWh)	$ 0.000124	$ 0.000124	$ 0.000124
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	290,500	290,500	290,500
Riders			
Non-Utility Generation Charge (Rider NGC)	290,500	290,500	290,500
Transitional Energy Facility Assessment Charge (Rider TEFA)	290,500	290,500	290,500
Societal Benefits Charge (Rider SBC)	290,500	290,500	290,500
Rider CIEP - Standby Fee	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 or AG)	630	630	630
Contract Demand (CD)	700	700	700

Charges Incurred - Detail	Primary	Transmission	High Tension Transmission
Delivery Service Charges			
Customer Charge	$ 59	$ 244	$ 244
Distribution Charges			
kW Charge	$ -	$ -	$ -
kWh Charge	$ 1,229	$ 992	$ 640
Riders			
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 Service Charges			
DR*BD	$ 5,986	$ 4,063	$ 2,984
SR*<MM or AG)	$ 1,506	$ 762	$ 762
SR*CD	$ 1,673	$ 847	$ 847
Standby Demand Charge (SDC=>[DR*BD)+(SR*<MM or AG)] or [SR*CD])	$ 7,491	$ 4,825	$ 3,746

Charges Incurred - Summary	Primary	Transmission	High Tension Transmission
Customer Charges	$ 59	$ 244	$ 244
Distribution Energy Charges	$ 1,229	$ 992	$ 640
Riders	$ 3,311	$ 3,213	$ 3,196
Standby Charges	$ 7,491	$ 4,825	$ 3,746
Total Charges	$ 12,091	$ 9,274	$ 7,826
$/kWh (Delivered Energy)	$ 0.04162	$ 0.03192	$ 0.02694
$/kWh (Total Monthly Energy)	$ 0.01577	$ 0.01210	$ 0.01021

Jersey Central Power & Light Company Standby Rates			
May through October	Voltage 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 Charge (Rider TEFA) ($/kWh)	$ 0.001312	$ 0.001029	$ 0.001029
Societal Benefits Charge (Rider SBC) ($/kWh)	$ 0.006817	$ 0.006817	$ 0.006817
Rider CIEP - Standby Fee ($/kWh)	$ 0.000150	$ 0.000150	$ 0.000150
System Control Charge (Rider SCC) ($/kWh)	$ 0.000055	$ 0.000055	$ 0.000055
RGGI Revovery Charge (Rider RRC) ($/kWh)	$ 0.000124	$ 0.000124	$ 0.000124
Standby Service Charges			
Demand Rate (DR)	$ 6.37	$ 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	290,500	290,500	290,500
Riders			
Non-Utility Generation Charge (Rider NGC)	290,500	290,500	290,500
Transitional Energy Facility Assessment Charge (Rider TEFA)	290,500	290,500	290,500
Societal Benefits Charge (Rider SBC)	290,500	290,500	290,500
Rider CIEP - Standby Fee	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 or AG)	630	630	630
Contract Demand (CD)	700	700	700

Charges Incurred - Detail	**Primary**	**Transmission**	**High Tension Transmission**
Delivery Service Charges			
Customer Charge	$ 59	$ 244	$ 244
Distribution Charges			
kW Charge	$ -	$ -	$ -
kWh Charge	$ 1,229	$ 992	$ 640
Riders			
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 Service Charges			
DR*BD	$ 5,542	$ 4,063	$ 2,984
SR*<MM or AG)	$ 1,506	$ 762	$ 762
SR*CD	$ 1,673	$ 847	$ 847
Standby Demand Charge (SDC=>[DR*BD)+(SR*<MM or AG)] or [SR*CD])	$ 7,048	$ 4,825	$ 3,746

Charges Incurred - Summary	**Primary**	**Transmission**	**High Tension Transmission**
Customer Charges	$ 59	$ 244	$ 244
Distribution Energy Charges	$ 1,229	$ 992	$ 640
Riders	$ 3,311	$ 3,213	$ 3,196
Standby Charges	$ 7,048	$ 4,825	$ 3,746
Total Charges	$ 11,647	$ 9,274	$ 7,826
$/kWh (Delivered Energy)	$ 0.04009	$ 0.03192	$ 0.02694
$/kWh (Total Monthly Energy)	$ 0.01520	$ 0.01210	$ 0.01021

Inputs

Season

Select Season From Drop Down	June through September	

Load Characteristics

Enter Peak Demand (kW)	6,000	kW
Enter Load Factor	80	%

Generator Characteristics

Enter Nameplate Capacity (kW)	4,000	kW
Enter Generator Availability	85	%
Enter Generator Maintenance Hours	60	Hours

Note: Outage Hours must be less than 730.

Monthly Billing Units

Facility Peak Demand	6,000	kW
Supplemental Demand	2,000	kW
Standby Demand	4,000	kW
Total Energy	3,504,000	kWh
On-Site Generated Energy	2,680,000	kWh
Delivered Energy	824,000	kWh

Standby Service Tariff Units

BD	2,600	kW
MM	6,000	kW
AG	3,400	kW
CR	4,000	kW
CD	4,000	kW
GA	85%	
SM	60	Hours

Jersey Central Power & Light Company Standby Rates			
June through September	Voltage 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
Riders			
Non-Utility Generation Charge (Rider NGC) ($/kWh)	$ 0.002941	$ 0.002885	$ 0.002826
Transitional Energy Facility Assessment Charge (Rider TEFA) ($/kWh)	$ 0.001312	$ 0.001029	$ 0.001029
Societal Benefits Charge (Rider SBC) ($/kWh)	$ 0.006817	$ 0.006817	$ 0.006817
Rider CIEP - Standby Fee ($/kWh)	$ 0.000150	$ 0.000150	$ 0.000150
System Control Charge (Rider SCC) ($/kWh)	$ 0.000055	$ 0.000055	$ 0.000055
RGGI Revovery Charge (Rider RRC) ($/kWh)	$ 0.000124	$ 0.000124	$ 0.000124
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 (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
Minimum of Max Monthly demand or Average Generation (<MM or AG)	3,400	3,400	3,400
Contract Demand (CD)	4,000	4,000	4,000

Charges Incurred - Detail	Primary	Transmission	High Tension Transmission
Delivery Service Charges			
Customer Charge	$ 59	$ 244	$ 244
Distribution Charges			
kW Charge	$ -	$ -	$ -
kWh Charge	$ 3,487	$ 2,814	$ 1,815
Riders			
Non-Utility Generation Charge (Rider NGC)	$ 2,423	$ 2,377	$ 2,329
Transitional Energy Facility Assessment Charge (Rider TEFA)	$ 1,081	$ 848	$ 848
Societal Benefits Charge (Rider SBC)	$ 5,617	$ 5,617	$ 5,617
Rider CIEP - Standby Fee	$ 124	$ 124	$ 124
System Control Charge (Rider SCC)	$ 45	$ 45	$ 45
RGGI Revovery Charge (Rider RRC)	$ 102	$ 102	$ 102
Standby Service Charges			
DR*BD	$ 17,888	$ 12,142	$ 8,918
SR*<MM or AG)	$ 8,126	$ 4,114	$ 4,114
SR*CD	$ 9,560	$ 4,840	$ 4,840
Standby Demand Charge (SDC=>[DR*BD)+(SR*<MM or AG)] or [SR*CD])	$ 26,014	$ 16,256	$ 13,032

Charges Incurred - Summary	Primary	Transmission	High Tension Transmission
Customer Charges	$ 59	$ 244	$ 244
Distribution Energy Charges	$ 3,487	$ 2,814	$ 1,815
Riders	$ 9,393	$ 9,113	$ 9,065
Standby Charges	$ 26,014	$ 16,256	$ 13,032
Total Charges	$ 38,953	$ 28,427	$ 24,156
$/kWh (Delivered Energy)	$ 0.04727	$ 0.03450	$ 0.02932
$/kWh (Total Monthly Energy)	$ 0.01112	$ 0.00811	$ 0.00689

Jersey Central Power & Light Company Standby Rates			
May through October	Voltage 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 Charge (Rider TEFA) ($/kWh)	$ 0.001312	$ 0.001029	$ 0.001029
Societal Benefits Charge (Rider SBC) ($/kWh)	$ 0.006817	$ 0.006817	$ 0.006817
Rider CIEP - Standby Fee ($/kWh)	$ 0.000150	$ 0.000150	$ 0.000150
System Control Charge (Rider SCC) ($/kWh)	$ 0.000055	$ 0.000055	$ 0.000055
RGGI Revovery Charge (Rider RRC) ($/kWh)	$ 0.000124	$ 0.000124	$ 0.000124
Standby Service Charges			
Demand Rate (DR)	$ 6.37	$ 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 (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
Minimum of Max Monthly demand or Average Generation (<MM or AG)	3,400	3,400	3,400
Contract Demand (CD)	4,000	4,000	4,000

Charges Incurred - Detail	**Primary**	**Transmission**	**High Tension Transmission**
Delivery Service Charges			
Customer Charge	$ 59	$ 244	$ 244
Distribution Charges			
kW Charge	$ -	$ -	$ -
kWh Charge	$ 3,487	$ 2,814	$ 1,815
Riders			
Non-Utility Generation Charge (Rider NGC)	$ 2,423	$ 2,377	$ 2,329
Transitional Energy Facility Assessment Charge (Rider TEFA)	$ 1,081	$ 848	$ 848
Societal Benefits Charge (Rider SBC)	$ 5,617	$ 5,617	$ 5,617
Rider CIEP - Standby Fee	$ 124	$ 124	$ 124
System Control Charge (Rider SCC)	$ 45	$ 45	$ 45
RGGI Revovery Charge (Rider RRC)	$ 102	$ 102	$ 102
Standby Service Charges			
DR*BD	$ 16,562	$ 12,142	$ 8,918
SR*<MM or AG)	$ 8,126	$ 4,114	$ 4,114
SR*CD	$ 9,560	$ 4,840	$ 4,840
Standby Demand Charge (SDC=>[DR*BD)+(SR*<MM or AG)] or [SR*CD])	$ 24,688	$ 16,256	$ 13,032

Charges Incurred - Summary	**Primary**	**Transmission**	**High Tension Transmission**
Customer Charges	$ 59	$ 244	$ 244
Distribution Energy Charges	$ 3,487	$ 2,814	$ 1,815
Riders	$ 9,393	$ 9,113	$ 9,065
Standby Charges	$ 24,688	$ 16,256	$ 13,032
Total Charges	$ 37,627	$ 28,427	$ 24,156
$/kWh (Delivered Energy)	$ 0.04566	$ 0.03450	$ 0.02932
$/kWh (Total Monthly Energy)	$ 0.01074	$ 0.00811	$ 0.00689

Inputs

Season

Select Season From Drop Down	June through September	

Load Characteristics

Enter Peak Demand (kW)	30,000	kW
Enter Load Factor	75	%

Generator Characteristics

Enter Nameplate Capacity (kW)	20,000	kW
Enter Generator Availability	90	%
Enter Generator Maintenance Hours	30	Hours

Note: Outage Hours must be less than 730.

Monthly Billing Units

Facility Peak Demand	30,000	kW
Supplemental Demand	10,000	kW
Standby Demand	20,000	kW
Total Energy	16,425,000	kWh
On-Site Generated Energy	14,000,000	kWh
Delivered Energy	2,425,000	kWh

Standby Service Tariff Units

BD	12,000	kW
MM	30,000	kW
AG	18,000	kW
CR	20,000	kW
CD	20,000	kW
GA	90%	
SM	30	Hours

Jersey Central Power & Light Company Standby Rates			
June through September	Voltage 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
Riders			
Non-Utility Generation Charge (Rider NGC) ($/kWh)	$ 0.002941	$ 0.002885	$ 0.002826
Transitional Energy Facility Assessment Charge (Rider TEFA) ($/kWh)	$ 0.001312	$ 0.001029	$ 0.001029
Societal Benefits Charge (Rider SBC) ($/kWh)	$ 0.006817	$ 0.006817	$ 0.006817
Rider CIEP - Standby Fee ($/kWh)	$ 0.000150	$ 0.000150	$ 0.000150
System Control Charge (Rider SCC) ($/kWh)	$ 0.000055	$ 0.000055	$ 0.000055
RGGI Revovery Charge (Rider RRC) ($/kWh)	$ 0.000124	$ 0.000124	$ 0.000124
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	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
Standby Service Charges			
Billing Demand (BD)	12,000	12,000	12,000
Minimum of Max Monthly demand or Average Generation (<MM or AG)	18,000	18,000	18,000
Contract Demand (CD)	20,000	20,000	20,000

Charges Incurred - Detail	Primary	Transmission	High Tension Transmission
Delivery Service Charges			
Customer Charge	$ 59	$ 244	$ 244
Distribution Charges			
kW Charge	$ -	$ -	$ -
kWh Charge	$ 10,263	$ 8,281	$ 5,342
Riders			
Non-Utility Generation Charge (Rider NGC)	$ 7,132	$ 6,996	$ 6,853
Transitional Energy Facility Assessment Charge (Rider TEFA)	$ 3,182	$ 2,495	$ 2,495
Societal Benefits Charge (Rider SBC)	$ 16,531	$ 16,531	$ 16,531
Rider CIEP - Standby Fee	$ 364	$ 364	$ 364
System Control Charge (Rider SCC)	$ 133	$ 133	$ 133
RGGI Revovery Charge (Rider RRC)	$ 301	$ 301	$ 301
Standby Service Charges			
DR*BD	$ 82,560	$ 56,040	$ 41,160
SR*<MM or AG)	$ 43,020	$ 21,780	$ 21,780
SR*CD	$ 47,800	$ 24,200	$ 24,200
Standby Demand Charge (SDC=>[DR*BD)+(SR*<MM or AG)] or [SR*CD])	$ 125,580	$ 77,820	$ 62,940

Charges Incurred - Summary	Primary	Transmission	High Tension Transmission
Customer Charges	$ 59	$ 244	$ 244
Distribution Energy Charges	$ 10,263	$ 8,281	$ 5,342
Riders	$ 27,643	$ 26,821	$ 26,677
Standby Charges	$ 125,580	$ 77,820	$ 62,940
Total Charges	$ 163,544	$ 113,166	$ 95,204
$/kWh (Delivered Energy)	$ 0.06744	$ 0.04667	$ 0.03926
$/kWh (Total Monthly Energy)	$ 0.00996	$ 0.00689	$ 0.00580

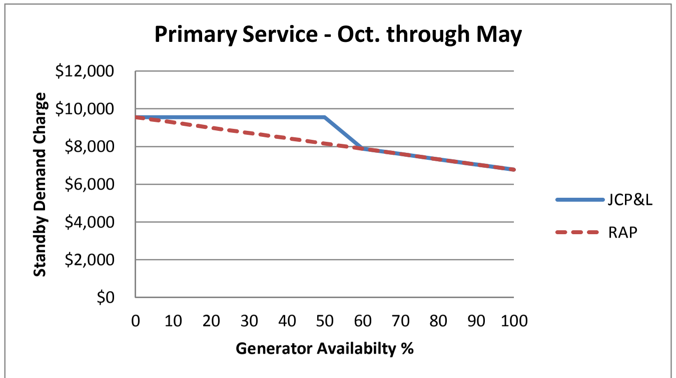
Jersey Central Power & Light Company Standby Rates			
May through October	Voltage Level		
Rates as of October 1, 2012	Primary	Transmission	High Tension Transmission
Delivery Service Charges			
Customer Charge	$ 59.06	$ 243.81	$ 243.81
Distribution Charges			
kW Charge (DR)	$ 6.37	$ 4.67	$ 3.43
kWh Charge	$ 0.004232	$ 0.003415	$ 0.002203
Riders			
Non-Utility Generation Charge (Rider NGC) ($/kWh)	$ 0.002941	$ 0.002885	$ 0.002826
Transitional Energy Facility Assessment Charge (Rider TEFA) ($/kWh)	$ 0.001312	$ 0.001029	$ 0.001029
Societal Benefits Charge (Rider SBC) ($/kWh)	$ 0.006817	$ 0.006817	$ 0.006817
Rider CIEP - Standby Fee ($/kWh)	$ 0.000150	$ 0.000150	$ 0.000150
System Control Charge (Rider SCC) ($/kWh)	$ 0.000055	$ 0.000055	$ 0.000055
RGGI Revovery Charge (Rider RRC) ($/kWh)	$ 0.000124	$ 0.000124	$ 0.000124
Standby Service Charges			
Demand Rate (DR)	$ 6.37	$ 4.67	$ 3.43
Standby Rate (SR)	$ 2.39	$ 1.21	$ 1.21

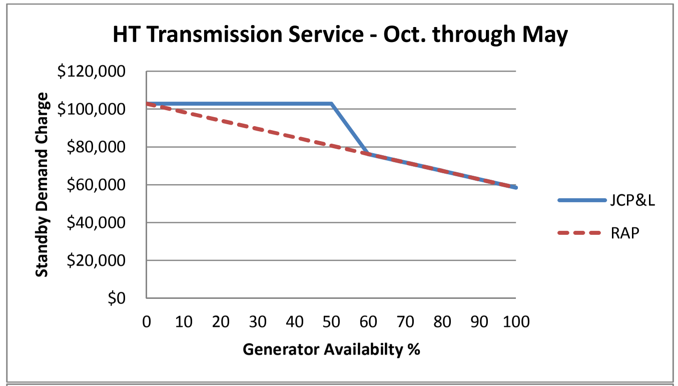
Billable Units	Primary	Transmission	High Tension Transmission
Delivery Service Charges			
Customer Charge	1	1	1
Distribution Charges			
kW Charge	-	-	-
kWh Charge	2,425,000	2,425,000	2,425,000
Riders			
Non-Utility Generation Charge (Rider NGC)	2,425,000	2,425,000	2,425,000
Transitional Energy Facility 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
Standby Service Charges			
Billing Demand (BD)	12,000	12,000	12,000
Minimum of Max Monthly demand or Average Generation (<MM or AG)	18,000	18,000	18,000
Contract Demand (CD)	20,000	20,000	20,000

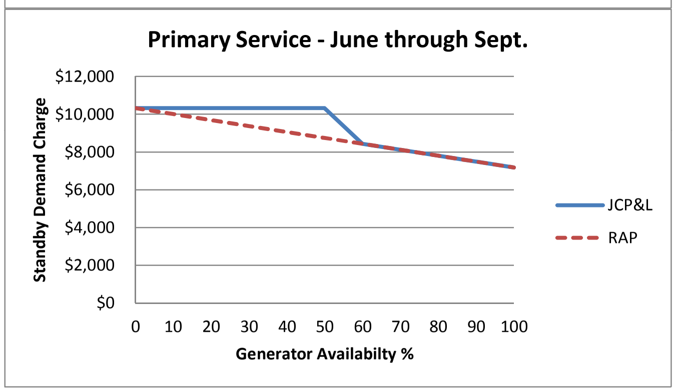
Charges Incurred - Detail	Primary	Transmission	High Tension Transmission
Delivery Service Charges			
Customer Charge	$ 59	$ 244	$ 244
Distribution Charges			
kW Charge	$ -	$ -	$ -
kWh Charge	$ 10,263	$ 8,281	$ 5,342
Riders			
Non-Utility Generation Charge (Rider NGC)	$ 7,132	$ 6,996	$ 6,853
Transitional Energy Facility Assessment Charge (Rider TEFA)	$ 3,182	$ 2,495	$ 2,495
Societal Benefits Charge (Rider SBC)	$ 16,531	$ 16,531	$ 16,531
Rider CIEP - Standby Fee	$ 364	$ 364	$ 364
System Control Charge (Rider SCC)	$ 133	$ 133	$ 133
RGGI Revovery Charge (Rider RRC)	$ 301	$ 301	$ 301
Standby Service Charges			
DR*BD	$ 76,440	$ 56,040	$ 41,160
SR*<MM or AG)	$ 43,020	$ 21,780	$ 21,780
SR*CD	$ 47,800	$ 24,200	$ 24,200
Standby Demand Charge (SDC=>[DR*BD)+(SR*<MM or AG)] or [SR*CD])	$ 119,460	$ 77,820	$ 62,940

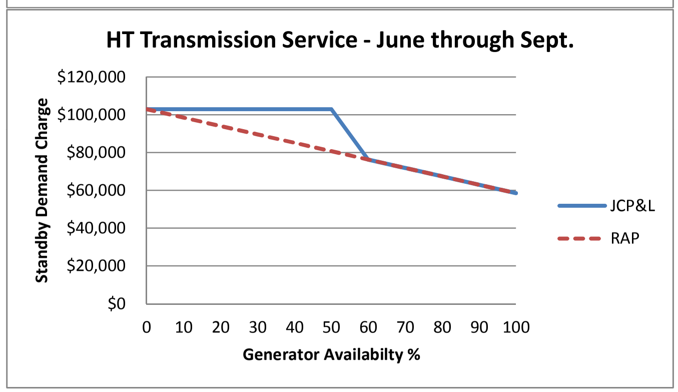
Charges Incurred - Summary	Primary	Transmission	High Tension Transmission
Customer Charges	$ 59	$ 244	$ 244
Distribution Energy Charges	$ 10,263	$ 8,281	$ 5,342
Riders	$ 27,643	$ 26,821	$ 26,677
Standby Charges	$ 119,460	$ 77,820	$ 62,940
Total Charges	$ 157,424	$ 113,166	$ 95,204
$/kWh (Delivered Energy)	$ 0.06492	$ 0.04667	$ 0.03926
$/kWh (Total Monthly Energy)	$ 0.00958	$ 0.00689	$ 0.00580

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









Assumptions
Peak Demand = 1,500 kW
Load Factor = 75%
Gen Nameplate Capacity = 700 kW

Assumptions
Peak Demand = 30,000 kW
Load Factor = 70%
Gen Nameplate Capacity = 20,000 kW

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

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 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.

- **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 ¢/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.

- **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.

Load Characteristics

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

Ohio Power Company - Columbus Southern
Schedule SBS
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	700	$ 4,448
Energy (kWh)	357,700	$ -
Riders		$ 1,995
Customer	1	$ -
Subtotal		$ 6,443
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	51,100	$ 405
Riders		$ 2,625
Customer	1	$ -
Subtotal		$ 3,030
Cost (¢/kWh)		**5.9293**
Supplemental		
Demand (kW)	800	$ 10,276
Energy (kWh)	255,500	$ 18
Riders		$ 16,204
Customer	1	$ 115
Subtotal		$ 26,614
Cost (¢/kWh)		**10.4164**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	102,200	$ -
Riders		$ 5,063
Customer	1	$ -
Subtotal		$ 5,063
Cost (¢/kWh)		**4.9541**
Totals		
Energy	766,500	$ 424
Demand	1,500	$ 14,724
Customer	1	$ 115
Rider		$ 25,887
Subtotal		$ 41,150
Cost (¢/kWh)		**5.3686**

Ohio Power Company - Columbus Southern
Schedule SBS-OAD
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	700	$ 2,228
Energy (kWh)	357,700	$ -
Riders		$ 1,448
Customer	1	$ -
Subtotal		$ 3,676
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	51,100	$ 1,672
Riders		$ 332
Customer	1	$ -
Subtotal		$ 2,004
Cost (¢/kWh)		**3.9224**
Supplemental		
Demand (kW)	800	$ 5,469
Energy (kWh)	255,500	$ 9,973
Riders		$ 2,176
Customer	1	$ 115
Subtotal		$ 17,733
Cost (¢/kWh)		**6.9405**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	102,200	$ 3,989
Riders		$ 664
Customer	1	$ -
Subtotal		$ 4,653
Cost (¢/kWh)		**4.5530**
Totals		
Energy	766,500	$ 15,634
Demand	1,500	$ 7,697
Customer	1	$ 115
Rider		$ 4,620
Subtotal		$ 28,067
Cost (¢/kWh)		**3.6617**

Load Characteristics

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

Ohio Power Company - Columbus Southern
Schedule SBS
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	4,000	$ 19,696
Energy (kWh)	2,336,000	$ -
Riders		$ 4,027
Customer	1	$ -
Subtotal		$ 23,723
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 2,316
Riders		$ 14,214
Customer	1	$ -
Subtotal		$ 16,530
Cost (¢/kWh)		**5.6608**
Supplemental		
Demand (kW)	2,000	$ 25,690
Energy (kWh)	584,000	$ 42
Riders		$ 37,588
Customer	1	$ 115
Subtotal		$ 63,435
Cost (¢/kWh)		**10.8622**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ -
Riders		$ 14,350
Customer	1	$ -
Subtotal		$ 14,350
Cost (¢/kWh)		**4.9145**
Totals		
Energy	3,504,000	$ 2,358
Demand	6,000	$ 45,386
Customer	1	$ 115
Rider		$ 70,179
Subtotal		$ 118,038
Cost (¢/kWh)		**3.3687**

Ohio Power Company - Columbus Southern
Schedule SBS-OAD
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	4,000	$ 12,732
Energy (kWh)	2,336,000	$ -
Riders		$ 2,413
Customer	1	$ -
Subtotal		$ 15,145
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 9,556
Riders		$ 1,113
Customer	1	$ -
Subtotal		$ 10,669
Cost (¢/kWh)		**3.6539**
Supplemental		
Demand (kW)	2,000	$ 13,672
Energy (kWh)	584,000	$ 22,795
Riders		$ 5,035
Customer	1	$ 115
Subtotal		$ 41,616
Cost (¢/kWh)		**7.1261**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 11,397
Riders		$ 1,782
Customer	1	$ -
Subtotal		$ 13,179
Cost (¢/kWh)		**4.5134**
Totals		
Energy	3,504,000	$ 43,748
Demand	6,000	$ 26,404
Customer	1	$ 115
Rider		$ 10,343
Subtotal		$ 80,610
Cost (¢/kWh)		**2.3005**

Load Characteristics		
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

Ohio Power Company - Columbus Southern
Schedule SBS
Rate Class: Subtransmission/Transmission

	Units	Cost
Standby		
Demand (kW)	20,000	$ 17,440
Energy (kWh)	13,140,000	$ -
Riders		$ 3,995
Customer	1	$ -
Subtotal		$ 21,435
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 1,886
Riders		$ 34,179
Customer	1	$ -
Subtotal		$ 36,065
Cost (¢/kWh)		**4.9404**
Supplemental		
Demand (kW)	10,000	$ 59,735
Energy (kWh)	1,825,000	$ -
Riders		$ 115,782
Customer	1	$ 1,060
Subtotal		$ 176,577
Cost (¢/kWh)		**9.6754**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ -
Riders		$ 33,581
Customer	1	$ -
Subtotal		$ 33,581
Cost (¢/kWh)		**4.6001**
Totals		
Energy	16,425,000	$ 1,886
Demand	30,000	$ 77,175
Customer	1	$ 1,060
Rider		$ 187,536
Subtotal		$ 267,657
Cost (¢/kWh)		**1.6296**

Ohio Power Company - Columbus Southern
Schedule SBS-OAD
Rate Class: Subtransmission/Transmission

	Units	Cost
Standby		
Demand (kW)	20,000	$ -
Energy (kWh)	13,140,000	$ -
Riders		$ -
Customer	1	$ -
Subtotal		$ -
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 23,890
Riders		$ 2,783
Customer	1	$ -
Subtotal		$ 26,673
Cost (¢/kWh)		**3.6539**
Supplemental		
Demand (kW)	10,000	$ 10,959
Energy (kWh)	1,825,000	$ 71,233
Riders		$ 9,408
Customer	1	$ 1,060
Subtotal		$ 92,660
Cost (¢/kWh)		**5.0773**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 28,493
Riders		$ 2,783
Customer	1	$ -
Subtotal		$ 31,277
Cost (¢/kWh)		**4.2845**
Totals		
Energy	16,425,000	$ 123,616
Demand	30,000	$ 10,959
Customer	1	$ 1,060
Rider		$ 14,975
Subtotal		$ 150,610
Cost (¢/kWh)		**0.9170**

Load Characteristics

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

Ohio Power Company - Ohio Power
Schedule SBS
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	700	$ 3,906
Energy (kWh)	357,700	$ -
Riders		$ 2,542
Customer	1	$ -
Subtotal		$ 6,448
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	51,100	$ 466
Riders		$ 2,282
Customer	1	$ -
Subtotal		$ 2,749
Cost (¢/kWh)		**5.3790**
Supplemental		
Demand (kW)	800	$ 10,184
Energy (kWh)	255,500	$ 489
Riders		$ 14,329
Customer	1	$ 95
Subtotal		$ 25,098
Cost (¢/kWh)		**9.8229**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	102,200	$ 314
Riders		$ 4,244
Customer	1	$ -
Subtotal		$ 4,558
Cost (¢/kWh)		**4.4597**
Totals		
Energy	766,500	$ 1,269
Demand	1,500	$ 14,090
Customer	1	$ 95
Rider		$ 23,397
Subtotal		$ 38,852
Cost (¢/kWh)		**5.0687**

Ohio Power Company - Ohio Power
Schedule SBS-OAD
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	700	$ 2,632
Energy (kWh)	357,700	$ -
Riders		$ 1,541
Customer	1	$ -
Subtotal		$ 4,173
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	51,100	$ 1,672
Riders		$ 309
Customer	1	$ -
Subtotal		$ 1,981
Cost (¢/kWh)		**3.8773**
Supplemental		
Demand (kW)	800	$ 5,930
Energy (kWh)	255,500	$ 9,973
Riders		$ 2,352
Customer	1	$ 95
Subtotal		$ 18,351
Cost (¢/kWh)		**7.1823**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	102,200	$ 3,989
Riders		$ 618
Customer	1	$ -
Subtotal		$ 4,607
Cost (¢/kWh)		**4.5079**
Totals		
Energy	766,500	$ 15,634
Demand	1,500	$ 8,562
Customer	1	$ 95
Rider		$ 4,820
Subtotal		$ 29,112
Cost (¢/kWh)		**3.7981**

Load Characteristics

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

Ohio Power Company - Ohio Power
Schedule SBS
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	4,000	$ 18,040
Energy (kWh)	2,336,000	$ -
Riders		$ 6,704
Customer	1	$ -
Subtotal		$ 24,744
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 2,664
Riders		$ 12,386
Customer	1	$ -
Subtotal		$ 15,050
Cost (¢/kWh)		**5.1541**
Supplemental		
Demand (kW)	2,000	$ 25,460
Energy (kWh)	584,000	$ 1,117
Riders		$ 33,368
Customer	1	$ 95
Subtotal		$ 60,041
Cost (¢/kWh)		**10.2810**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 898
Riders		$ 12,028
Customer	1	$ -
Subtotal		$ 12,926
Cost (¢/kWh)		**4.4266**
Totals		
Energy	3,504,000	$ 4,679
Demand	6,000	$ 43,500
Customer	1	$ 95
Rider		$ 64,485
Subtotal		$ 112,760
Cost (¢/kWh)		**3.2180**

Ohio Power Company - Ohio Power
Schedule SBS-OAD
Rate Class: Primary

	Units	Cost
Standby		
Demand (kW)	4,000	$ 15,040
Energy (kWh)	2,336,000	$ -
Riders		$ 3,867
Customer	1	$ -
Subtotal		$ 18,907
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 9,556
Riders		$ 1,109
Customer	1	$ -
Subtotal		$ 10,665
Cost (¢/kWh)		**3.6524**
Supplemental		
Demand (kW)	2,000	$ 14,826
Energy (kWh)	584,000	$ 22,795
Riders		$ 5,499
Customer	1	$ 95
Subtotal		$ 43,215
Cost (¢/kWh)		**7.3998**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	292,000	$ 11,397
Riders		$ 1,669
Customer	1	$ -
Subtotal		$ 13,066
Cost (¢/kWh)		**4.4748**
Totals		
Energy	3,504,000	$ 43,748
Demand	6,000	$ 29,866
Customer	1	$ 95
Rider		$ 12,144
Subtotal		$ 85,853
Cost (¢/kWh)		**2.4501**

Load Characteristics		
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

Ohio Power Company - Ohio Power
Schedule SBS
Rate Class: Transmission

	Units	Cost
Standby		
Demand (kW)	20,000	$ 6,400
Energy (kWh)	13,140,000	$ -
Riders		$ 6,820
Customer	1	$ -
Subtotal		$ 13,220
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 2,394
Riders		$ 29,291
Customer	1	$ -
Subtotal		$ 31,685
Cost (¢/kWh)		**4.3404**
Supplemental		
Demand (kW)	10,000	$ 93,800
Energy (kWh)	1,825,000	$ 866
Riders		$ 99,476
Customer	1	$ 512
Subtotal		$ 194,655
Cost (¢/kWh)		**10.6660**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 2,394
Riders		$ 28,160
Customer	1	$ -
Subtotal		$ 30,554
Cost (¢/kWh)		**4.1855**
Totals		
Energy	16,425,000	$ 5,654
Demand	30,000	$ 100,200
Customer	1	$ 512
Rider		$ 163,747
Subtotal		$ 270,113
Cost (¢/kWh)		**1.6445**

Ohio Power Company - Ohio Power
Schedule SBS-OAD
Rate Class: Transmission

	Units	Cost
Standby		
Demand (kW)	20,000	$ -
Energy (kWh)	13,140,000	$ -
Riders		$ -
Customer	1	$ -
Subtotal		$ -
Maintenance		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 23,890
Riders		$ 2,773
Customer	1	$ -
Subtotal		$ 26,663
Cost (¢/kWh)		**3.6524**
Supplemental		
Demand (kW)	10,000	$ 36,530
Energy (kWh)	1,825,000	$ 71,233
Riders		$ 8,946
Customer	1	$ 512
Subtotal		$ 117,221
Cost (¢/kWh)		**6.4230**
Backup		
Demand (kW)	-	$ -
Energy (kWh)	730,000	$ 28,493
Riders		$ 2,773
Customer	1	$ -
Subtotal		$ 31,266
Cost (¢/kWh)		**4.2830**
Totals		
Energy	16,425,000	$ 123,616
Demand	30,000	$ 36,530
Customer	1	$ 512
Rider		$ 14,491
Subtotal		$ 175,149
Cost (¢/kWh)		**1.0664**

Columbus Southern Rate Zone Economic Analysis - Schedule SBS

Small Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
700	20%	102,200	7	51,100	73	4

	Schedule SBS			Modified Schedule SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Generation	$3.171		$2,220	$0.483		$338
Transmission	$0.500		$350	$0.000		$0
Distribution	$3.183		$2,228	$2.546		$1,782
Total			$4,798			$2,120
Backup				**$/kW/Day**		
Generation				$0.30600		$1,499
Transmission		$0.00356	$364	$0.06680	$0.00373	$708
Distribution				$0.02122		$104
Total			$364			$2,312
Maintenance						
Generation		$0.00280	$143	$0.1530		$428
Transmission		$0.00417	$213	$0.0334	$0.00186	$189
Distribution		$0.00513	$262	$0.0106		$30
Total			$618			$647
TOTAL			**$5,780**			**$5,079**

Medium Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
4,000	10%	292,000	4	292,000	73	4

	Schedule SBS			Modified Schedule SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Generation	$1.741		$6,964	$0.483		$1,932
Transmission	$0.250		$1,000	$0.000		$0
Distribution	$3.183		$12,732	$2.546		$10,184
Total			$20,696			$12,116
Backup				**$/kW/Day**		
Generation				$0.30600		$4,896
Transmission		$0.00356	$1,040	$0.06680	$0.00373	$2,158
Distribution				$0.02122		$340
Total			$1,040			$7,393
Maintenance						
Generation		$0.00280	$818	$0.1530		$2,448
Transmission		$0.00417	$1,216	$0.0334	$0.00186	$1,079
Distribution		$0.00513	$1,498	$0.0106		$170
Total			$3,532			$3,697
TOTAL			**$25,268**			**$23,206**

Large Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
20,000	20%	2,920,000	7	730,000	36.5	2

	Schedule SBS			Modified Schedule SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Generation	$2.966		$59,320	$0.483		$9,660
Transmission	$0.123		$2,460	$0.000		$0
Distribution	$0.000		$0	$0.000		$0
Total			$61,780			$9,660
Backup				**$/kW/Day**		
Generation				$0.30600		$42,840
Transmission		$0.00349	$10,202	$0.08357	$0.00257	$19,202
Distribution				$0.00000		$0
Total			$10,202			$62,042
Maintenance						
Generation		$0.00258	$7,544	$0.1530		$6,120
Transmission		$0.00409	$11,932	$0.0418	$0.0013	$2,609
Distribution		$0.00000	$0	$0.0000		$0
Total			$19,476			$8,729
TOTAL			**$91,459**			**$80,432**

Ohio Power Rate Zone Economic Analysis - Schedule SBS

Small Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
700	20%	102,200	7	51,100	73	4

	Schedule SBS			Modified Schedule SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Generation	$1.820		$1,274	$0.449		$314
Transmission	$1.310		$917	$0.000		$0
Distribution	$3.760		$2,632	$3.008		$2,106
Total			$4,823			$2,420
Backup				**$/kW/Day**		
Generation		$0.00307	$314	$0.28400		$1,392
Transmission		$0.00218	$223	$0.07630	$0.00217	$595
Distribution				$0.02510		$123
Total			$537			$2,110
Maintenance						
Generation		$0.00280	$143	$0.1420		$398
Transmission		$0.00377	$193	$0.0382	$0.00108	$162
Distribution		$0.00513	$262	$0.0126		$35
Total			$598			$595
TOTAL			**$5,958**			**$5,125**

Medium Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
4,000	10%	292,000	4	292,000	73	4

	Schedule SBS			Modified Schedule SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Generation	$0.750		$3,000	$0.449		$1,796
Transmission	$0.660		$2,640	$0.000		$0
Distribution	$3.760		$15,040	$3.008		$12,032
Total			$20,680			$13,828
Backup				**$/kW/Day**		
Generation		$0.00307	$898	$0.28400		$4,544
Transmission		$0.00218	$637	$0.07630	$0.00217	$1,853
Distribution				$0.02510		$402
Total			$1,535			$6,799
Maintenance						
Generation		$0.00280	$818	$0.1420		$2,272
Transmission		$0.00377	$1,101	$0.0382	$0.00108	$927
Distribution		$0.00513	$1,498	$0.0126		$201
Total			$3,417			$3,400
TOTAL			**$25,632**			**$24,027**

Large Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
20,000	5%	730,000	2	730,000	36.5	2

	Schedule SBS			Modified Schedule SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Generation	$0.320		$6,400	$0.429		$8,580
Transmission	$0.320		$6,400	$0.000		$0
Distribution	$0.000		$0	$0.000		$0
Total			$12,800			$8,580
Backup				**$/kW/Day**		
Generation		$0.00328	$2,394	$0.27100		$10,840
Transmission		$0.00213	$1,555	$0.07430	$0.00211	$4,516
Distribution				$0.00000		$0
Total			$3,949			$15,356
Maintenance						
Generation		$0.00258	$1,886	$0.1355		$5,420
Transmission		$0.00368	$2,686	$0.0372	$0.0011	$2,258
Distribution		$0.00000	$0	$0.0000		$0
Total			$4,572			$7,678
TOTAL			**$21,321**			**$31,613**

Columbus Southern Rate Zone Economic Analysis - Schedule OAD-SBS

Small Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
700	20%	102,200	7	51,100	73	4

	Schedule OAD-SBS			Modified Schedule OAD-SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Distribution	$3.183		$2,228	$2.546		$1,782
Backup				**$/kW/Day**		
Distribution				$0.02122		$104
Maintenance						
Distribution				$0.0212		$59
Total			**$2,228**			**$1,946**

Medium Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
4,000	10%	292,000	4	292,000	73	4

	Schedule OAD-SBS			Modified Schedule OAD-SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Distribution	$3.183		$12,732	$2.546		$10,184
Backup				**$/kW/Day**		
Distribution				$0.02122		$340
Maintenance						
Distribution				$0.0212		$340
TOTAL			**$12,732**			**$10,863**

Large Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
20,000	5%	730,000	2	730,000	36.5	2

	Schedule OAD-SBS			Modified Schedule OAD-SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Distribution						
Backup						
Distribution						
Maintenance						
Distribution						

Ohio Power Rate Zone Economic Analysis - Schedule OAD-SBS

Small Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
700	20%	102,200	7	51,100	73	4

	Schedule OAD-SBS			Modified Schedule OAD-SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Distribution	$3.760		$2,632	$3.008		$2,106
Backup				**$/kW/Day**		
Distribution				$0.0251		$123
Maintenance						
Distribution				$0.0251		$70
Total			**$2,632**			**$2,299**

Medium Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
4,000	10%	292,000	4	292,000	73	4

	Schedule OAD-SBS			Modified Schedule OAD-SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Distribution	$3.760		$15,040	$3.008		$12,032
Backup				**$/kW/Day**		
Distribution				$0.02507		$401
Maintenance						
Distribution				$0.0251		$401
TOTAL			**$15,040**			**$12,834**

Large Load Economic Analysis

Self Gen. kW	Forced Outage	Backup kWh	Backup Days	Maint. kWh	Maint. Hours	Maint. Days
20,000	5%	730,000	2	730,000	36.5	2

	Schedule OAD-SBS			Modified Schedule OAD-SBS		
Standby	**$/kW**	**$/kWh**	**Charges**	**$/kW**	**$/kWh**	**Charges**
Distribution						
Backup						
Distribution						
Maintenance						
Distribution						

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.

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.

- **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.

Inputs

Season

Select Season From Drop Down	October through April	

Load Characteristics

Enter Peak Demand (kW)	4,350	kW
Enter Load Factor	75	%

Generator Characteristics

Enter Net Capability (kW)	1,950	kW
Enter Generator Load Factor	100	%
Enter Forced Outage Start Day	Monday	
Start Hour (1 = Hour Ending 1AM)	8	
Duration (hours)	48	Hours
Enter Maintenance Outage Start Day	Monday	
Start Hour (1 = Hour Ending 1AM)	24	
Duration (hours)	72	Hours

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

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

Monthly Billing Units

Total Demand	4,350	kW
Supplemental Demand	2,400	kW
Self Generation Demand	1,950	kW
Load Factor	75	%
Supplemental Load Factor	54.7	%
Back-up On Peak Days	3	Days
Maintenance On Peak Days	3	Days
Energy		
Monthly Energy	2,381,625	kWh
Supplemental Energy	958,125	kWh
Self Generation Energy	1,189,500	kWh
Back-up Energy	93,600	kWh
Maintenance Energy	140,400	kWh

Schedule 8 - Large General Service at Primary Voltage

October through April

Standby Charges

Total Standby Charges			Base Charges	Units	Rate	Charge
Customer	$ 527		Customer	1	$ 527.00	$ 527
Facilities	$ 6,533		Facilities	1,950	$ 3.35	$ 6,533
Power	$ -		Power	1,950	$ -	$ -
Energy	$ -		Energy	1,189,500	$ -	$ -
Riders	$ 193					
Total Cost	$ 7,253					
			Riders			
			Schedule 94 - Energy Balancing Account	$ -	1.34%	$ -
			Schedule 98 - REC Revenues Credit	-	-0.28%	$ -
			Schedule 193 - DSM Cost Adjustment	6,533	3.37%	$ 220
			Schedule 194 - DSM Cost Adj. Credit	6,533	-0.41%	$ (27)

Maintenance Charges

Total Maintenance Charges			Base Charges	Units	Rate	Charge
Customer	$ -		Customer	1	$ -	$ -
Facilities	$ -		Facilities	1,950	$ -	$ -
Power	$ 1,670		Power	5,850	$ 0.28550	$ 1,670
Energy	$ 4,406		Energy	140,400	$ 0.031382	$ 4,406
Riders	$ 244					
Total Cost	$ 6,320					
			Riders			
			Schedule 94 - Energy Balancing Account	$ 6,076	1.34%	$ 81
$/kWh	$ 0.0450		Schedule 98 - REC Revenues Credit	6,076	-0.28%	$ (17)
			Schedule 193 - DSM Cost Adjustment	6,076	3.37%	$ 205
			Schedule 194 - DSM Cost Adj. Credit	6,076	-0.41%	$ (25)

Forced Outage Charges

Total Forced Outage Charges			Base Charges	Units	Rate	Charge
Customer	$ -		Customer	1	$ -	$ -
Facilities	$ -		Facilities	1,950	$ -	$ -
Power	$ 3,340		Power	5,850	$ 0.5710	$ 3,340
Energy	$ 2,937		Energy	93,600	$ 0.031382	$ 2,937
Riders	$ 252					
Total Cost	$ 6,530					
			Riders			
			Schedule 94 - Energy Balancing Account	$ 6,278	1.34%	$ 84
$/kWh	$ 0.0698		Schedule 98 - REC Revenues Credit	6,278	-0.28%	$ (18)
			Schedule 193 - DSM Cost Adjustment	6,278	3.37%	$ 212
			Schedule 194 - DSM Cost Adj. Credit	6,278	-0.41%	$ (26)

Supplemental Charges

Total Supplemental Charges			Base Charges	Units	Rate	Charge
Customer	$ 62		Customer	1	$ 62.00	$ 62
Facilities	$ 10,128		Facilities	2,400	$ 4.22	$ 10,128
Power	$ 21,432		Power	2,400	$ 8.93	$ 21,432
Energy	$ 30,068		Energy	958,125	$ 0.031382	$ 30,068
Riders	$ 2,271					
Total Cost	$ 63,961					
			Riders			
			Schedule 94 - Energy Balancing Account	$ 51,500	1.34%	$ 690
$/kWh	$ 0.0668		Schedule 98 - REC Revenues Credit	51,500	-0.28%	$ (144)
			Schedule 193 - DSM Cost Adjustment	61,628	3.20%	$ 1,972
			Schedule 194 - DSM Cost Adj. Credit	61,628	-0.40%	$ (247)

Grand Total

Customer	**$ 589**
Facilities	**$ 16,661**
Power	**$ 26,443**
Energy	**$ 37,411**
Riders	**$ 2,961**
Total Cost	**$ 84,065**
$/kWh	**$ 0.0705**

Inputs

Season

Select Season From Drop Down	May through September	

Load Characteristics

Enter Peak Demand (kW)	19,500	kW
Enter Load Factor	80	%

Generator Characteristics

Enter Net Capability (kW)	7,500	kW
Enter Generator Load Factor	100	%
Enter Forced Outage Start Day	Monday	
Start Hour (1 = Hour Ending 1AM)	12	
Duration (hours)	48	Hours
Enter Maintenance Outage Start Day	Monday	
Start Hour (1 = Hour Ending 1AM)	24	
Duration (hours)	36	Hours

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

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

Monthly Billing Units

Total Demand	19,500	kW
Supplemental Demand	12,000	kW
Self Generation Demand	7,500	kW
Load Factor	80	%
Supplemental Load Factor	67.5	%
Back-up On Peak Days	2	Days
Maintenance On Peak Days	1	Days

Energy

Monthly Energy	11,388,000	kWh
Supplemental Energy	5,913,000	kWh
Self Generation Energy	4,845,000	kWh
Back-up Energy	360,000	kWh
Maintenance Energy	270,000	kWh

Schedule 9 - General Service at Transmission Voltage
May through September

Standby Charges

			Units	Rate	Charge
Total Standby Charges		**Base Charges**			
Customer	$ 590	Customer	1	$ 590.00	$ 590
Facilities	$ 14,250	Facilities	7,500	$ 1.90	$ 14,250
Power	$ -	Power	7,500	$ -	$ -
Energy	$ -	Energy	4,845,000	$ -	$ -
Riders	$ 422				
Total Cost	$ 15,262				
		Riders			
		Schedule 94 - Energy Balancing Account	$ -	1.47%	$ -
		Schedule 98 - REC Revenues Credit	-	-0.31%	$ -
		Schedule 193 - DSM Cost Adjustment	14,250	3.37%	$ 480
		Schedule 194 - DSM Cost Adj. Credit	14,250	-0.41%	$ (58)

Maintenance Charges

			Units	Rate	Charge
Total Maintenance Charges		**Base Charges**			
Customer	$ -	Customer	1	$ -	$ -
Facilities	$ -	Facilities	7,500	$ -	$ -
Power	$ 1,682	Power	7,500	$ 0.22425	$ 1,682
Energy	$ 7,852	Energy	270,000	$ 0.029083	$ 7,852
Riders	$ 393				
Total Cost	$ 9,927				
		Riders			
		Schedule 94 - Energy Balancing Account	$ 9,534	1.47%	$ 140
$/kWh	$ 0.0368	Schedule 98 - REC Revenues Credit	9,534	-0.31%	$ (30)
		Schedule 193 - DSM Cost Adjustment	9,534	3.37%	$ 321
		Schedule 194 - DSM Cost Adj. Credit	9,534	-0.41%	$ (39)

Forced Outage Charges

			Units	Rate	Charge
Total Forced Outage Charges		**Base Charges**			
Customer	$ -	Customer	1	$ -	$ -
Facilities	$ -	Facilities	7,500	$ -	$ -
Power	$ 6,728	Power	15,000	$ 0.4485	$ 6,728
Energy	$ 10,470	Energy	360,000	$ 0.029083	$ 10,470
Riders	$ 709				
Total Cost	$ 17,906				
		Riders			
		Schedule 94 - Energy Balancing Account	$ 17,197	1.47%	$ 253
$/kWh	$ 0.0497	Schedule 98 - REC Revenues Credit	17,197	-0.31%	$ (53)
		Schedule 193 - DSM Cost Adjustment	17,197	3.37%	$ 580
		Schedule 194 - DSM Cost Adj. Credit	17,197	-0.41%	$ (71)

Supplemental Charges

			Units	Rate	Charge
Total Supplemental Charges		**Base Charges**			
Customer	$ 226	Customer	1	$ 226.00	$ 226
Facilities	$ 23,280	Facilities	12,000	$ 1.94	$ 23,280
Power	$ 146,160	Power	12,000	$ 12.18	$ 146,160
Energy	$ 171,969	Energy	5,913,000	$ 0.029083	$ 171,969
Riders	$ 13,284				
Total Cost	$ 354,919				
		Riders			
		Schedule 94 - Energy Balancing Account	$ 318,129	1.47%	$ 4,676
$/kWh	$ 0.0600	Schedule 98 - REC Revenues Credit	318,129	-0.31%	$ (986)
		Schedule 193 - DSM Cost Adjustment	341,409	3.21%	$ 10,959
		Schedule 194 - DSM Cost Adj. Credit	341,409	-0.40%	$ (1,366)

Grand Total

Customer	**$ 816**
Facilities	**$ 37,530**
Power	**$ 154,569**
Energy	**$ 190,292**
Riders	**$ 14,807**
Total Cost	**$ 398,014**
$/kWh	**$ 0.0608**

Inputs

Season

Select Season From Drop Down	May through September	

Load Characteristics

Enter Peak Demand (kW)	25,000	kW
Enter Load Factor	80	%

Generator Characteristics

Enter Net Capability (kW)	25,000	kW
Enter Generator Load Factor	80	%
Enter Forced Outage Start Day	Monday	
Start Hour (1 = Hour Ending 1AM)	12	
Duration (hours)	48	Hours
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.

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

Monthly Billing Units

Total Demand	25,000	kW
Supplemental Demand	-	kW
Self Generation Demand	25,000	kW
Load Factor	80	%
Supplemental Load Factor	0.0	%
Back-up On Peak Days	2	Days
Maintenance On Peak Days	2	Days

Energy

Monthly Energy	14,600,000	kWh
Supplemental Energy	-	kWh
Self Generation Energy	12,680,000	kWh
Back-up Energy	960,000	kWh
Maintenance Energy	960,000	kWh

Schedule 9 - General Service at Transmission Voltage
May through September

Standby Charges

Total Standby Charges			Units	Rate	Charge
		Base Charges			
Customer	$ 590	Customer	1	$ 590.00	$ 590
Facilities	$ 47,500	Facilities	25,000	$ 1.90	$ 47,500
Power	$ -	Power	25,000	$ -	$ -
Energy	$ -	Energy	12,680,000	$ -	$ -
Riders	$ 1,406				
Total Cost	$ 49,496				
		Riders			
		Schedule 94 - Energy Balancing Account	$ -	1.47%	$ -
		Schedule 98 - REC Revenues Credit	-	-0.31%	$ -
		Schedule 193 - DSM Cost Adjustment	47,500	3.37%	$ 1,601
		Schedule 194 - DSM Cost Adj. Credit	47,500	-0.41%	$ (195)

Maintenance Charges

Total Maintenance Charges			Units	Rate	Charge
		Base Charges			
Customer	$ -	Customer	1	$ -	$ -
Facilities	$ -	Facilities	25,000	$ -	$ -
Power	$ 11,213	Power	50,000	$ 0.22425	$ 11,213
Energy	$ 27,920	Energy	960,000	$ 0.029083	$ 27,920
Riders	$ 1,612				
Total Cost	$ 40,745				
		Riders			
		Schedule 94 - Energy Balancing Account	$ 39,132	1.47%	$ 575
$/kWh	$ 0.0424	Schedule 98 - REC Revenues Credit	39,132	-0.31%	$ (121)
		Schedule 193 - DSM Cost Adjustment	39,132	3.37%	$ 1,319
		Schedule 194 - DSM Cost Adj. Credit	39,132	-0.41%	$ (160)

Forced Outage Charges

Total Forced Outage Charges			Units	Rate	Charge
		Base Charges			
Customer	$ -	Customer	1	$ -	$ -
Facilities	$ -	Facilities	25,000	$ -	$ -
Power	$ 22,425	Power	50,000	$ 0.4485	$ 22,425
Energy	$ 27,920	Energy	960,000	$ 0.029083	$ 27,920
Riders	$ 2,074				
Total Cost	$ 52,419				
		Riders			
		Schedule 94 - Energy Balancing Account	$ 50,345	1.47%	$ 740
$/kWh	$ 0.0546	Schedule 98 - REC Revenues Credit	50,345	-0.31%	$ (156)
		Schedule 193 - DSM Cost Adjustment	50,345	3.37%	$ 1,697
		Schedule 194 - DSM Cost Adj. Credit	50,345	-0.41%	$ (206)

Supplemental Charges

Total Supplemental Charges			Units	Rate	Charge
		Base Charges			
Customer	$ 226	Customer	1	$ 226.00	$ 226
Facilities	$ -	Facilities	-	$ 1.94	$ -
Power	$ -	Power	-	$ 12.18	$ -
Energy	$ -	Energy	-	$ 0.029083	$ -
Riders	$ -				
Total Cost	$ 226				
		Riders			
		Schedule 94 - Energy Balancing Account	$ -	1.47%	$ -
$/kWh	#DIV/0!	Schedule 98 - REC Revenues Credit	-	-0.31%	$ -
		Schedule 193 - DSM Cost Adjustment	-	3.21%	$ -
		Schedule 194 - DSM Cost Adj. Credit	-	-0.40%	$ -

Grand Total

Customer	**$ 816**
Facilities	**$ 47,500**
Power	**$ 33,638**
Energy	**$ 55,840**
Riders	**$ 5,092**
Total Cost	**$ 142,886**
$/kWh	**$ 0.0744**

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.

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

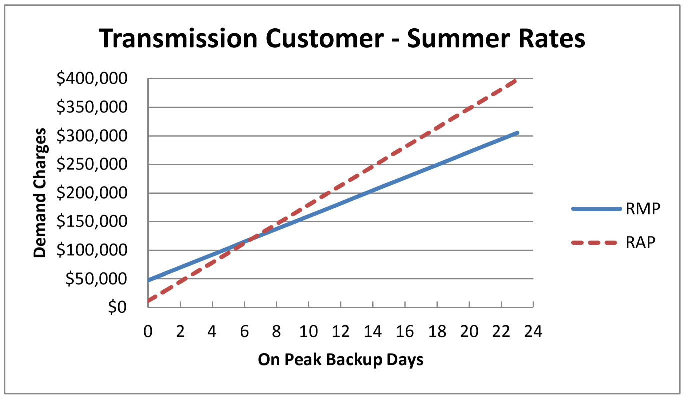
Notes:
1. Reservation charge only includes power costs.
2. Customer will pay facilities charge for dedicated facilities costs .

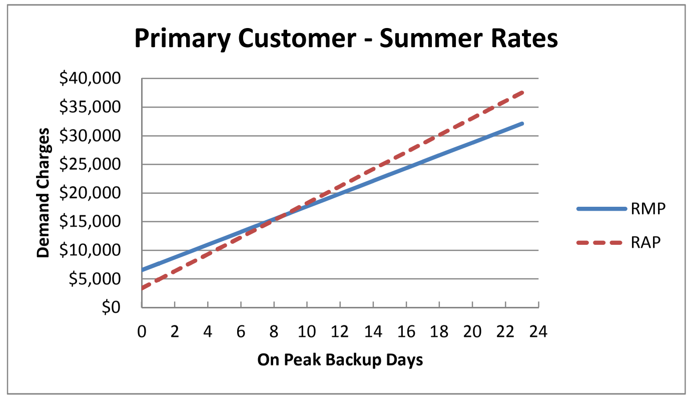
2. Modify back-up charges for seasonal difference and recovery of diversified T&D costs

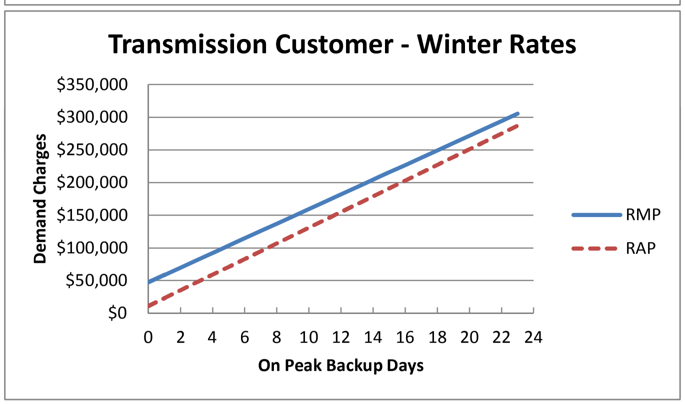
	Voltage Level	Current Annual On-Peak Backup $/kW/Day	Estimated On-Peak Summer Backup $/kW/Day	Estimated On-Peak Winter Backup $/kW/Day
6	Primary	$0.5710	$0.7619	$0.5708
7	Transmission	$0.4485	$0.6732	$0.4796

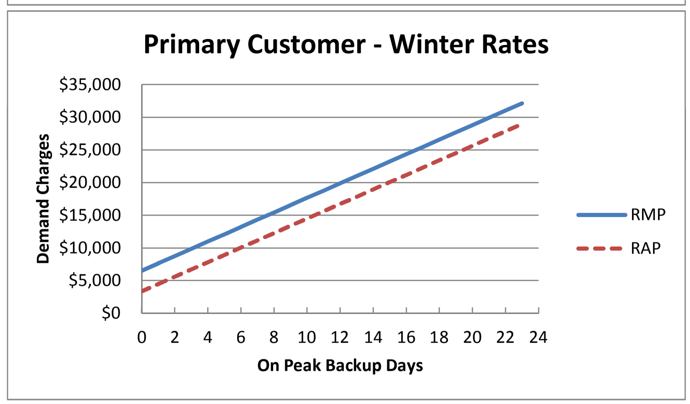
	Voltage Level	Current Annual On-Peak Annual Maintenance $/kW/Day	Estimated On-Peak Summer Maintenance $/kW/Day	Estimated On-Peak Winter Maintenance $/kW/Day
8	Primary	$0.2855	$0.3810	$0.2854
9	Transmission	$0.2243	$0.3366	$0.2398

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.