

Volume 2B

Direct Testimony and Supporting Schedules:

David G. Prazak

Rate Design

Before the South Dakota Public Utilities Commission

State of South Dakota

In the Matter of the Application of Otter Tail Power Company

For Authority to Increase Rates for Electric Utility

Service in South Dakota

Docket No. EL10-___

Exhibit___

RATE DESIGN

Direct Testimony and Schedules of

DAVID G. PRAZAK

August 20, 2010

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ATTACHED SCHEDULES

Schedule 1 – Qualifications and experience of David G. Prazak

Schedule 2 – Customer and Rate Class proposed Allocations and Revenues

Schedule 3 – Matrix of Miscellaneous Rate Schedule Changes

Schedule 4 – 2010 Marginal Cost Study

1 **I. INTRODUCTION AND QUALIFICATIONS**

2
3 Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

4 A. My name is David G. Prazak, my business address is 215 South Cascade Street,
5 Fergus Falls, Minnesota 56537.

6
7 Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

8 A. I am employed by Otter Tail Power Company (“Otter Tail Power,” or “OTP”) as its
9 Supervisor of Pricing. My current duties include managing the design and
10 implementation of retail pricing strategies for rate schedule and contract pricing,
11 including rates and rate design.

12
13 Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

14 A. I have over 21 years of experience in the energy industry and over 13 years of
15 experience in the Regulatory Economics Department in Pricing and Rate Design. My
16 qualifications and experience are more fully described on Exhibit __ (DGP-1),
17 Schedule 1.

18
19 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE ANY REGULATORY
20 AUTHORITIES?

21 A. Yes. I have testified before the South Dakota Public Utilities Commission
22 (“Commission”), Minnesota Public Utilities Commission and the North Dakota Public
23 Service Commission.

24
25 Q. FOR WHOM ARE YOU TESTIFYING?

26 A. I am testifying on behalf of OTP in support of the application to the Commission for
27 authority to increase rates.

28
29 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

30 A. The purpose of my direct testimony is to: (1) describe the rate structure objectives that
31 were used in developing the proposed rates; (2) explain the role of marginal costs; (3)

1 describe the proposed rate design for OTP’s rate schedules and riders; (4) describe the
2 development of OTP’s proposed changes to base rate schedules and riders; and (5)
3 support the proposed language changes of OTP’s rate schedule provisions.

4 The following is a list of the rate schedules and riders addressed in my testimony; I
5 have enumerated them with their proposed section numbers below:

- 6 • 9.01 Residential Service
- 7 • 9.02 Residential Service – Controlled Demand
- 8 • 9.03 Farm Service
- 9 • 10.01 Small General Service (less than 20 kW)
- 10 • 10.02 General Service (20 kW or greater)
- 11 • 10.03 General Service – Time of Use (f/n/a Commercial Time of Use)
- 12 • 10.04 Large General Service
- 13 • 10.05 Large General Service – Time of Day
- 14 • 11.01 Standby Service
- 15 • 11.02 Option 1: Irrigation Service – Non-Time-Of-Use
- 16 • 11.02 Option 2: Irrigation Service – Time-of-Use
- 17 • 11.03 Outdoor Lighting – Energy Only
- 18 • 11.04 Outdoor Lighting
- 19 • 11.05 Municipal Pumping Service
- 20 • 11.06 Civil Defense-Fire Sirens
- 21 • 12.01 Small Power Producer Rider-Net Energy Billing Rate
- 22 • 12.02 Small Power Producer Rider-Simultaneous Purchase
- 23 • 12.03 Small Power Producer Rider-Time of Day Purchase
- 24 • 12.04 Distributed Generation Rider
- 25 • 12.05 Community-Based Energy Development (CBED)
- 26 • 13.00 Mandatory Riders
- 27 • 14.01 Water Heating Controlled Service Rider
- 28 • 14.02 Real Time Pricing Rider
- 29 • 14.03 Large General Service Rider
- 30 • 14.04 Option 1: Controlled Service – Interruptible Load (CT Metering) Rider

- 1 • 14.04 Option 2: Controlled Service – Interruptible Load (CT Metering) Rider
- 2 • 14.05 Controlled Service – Interruptible Load (Self-contained metering) Rider
- 3 • 14.06 Controlled Service – Deferred Load Rider
- 4 • 14.07 Fixed Time of Service Rider
- 5 • 14.08 Air Conditioning Control Rider
- 6 • 14.09 Renewable Energy Rider
- 7 • 14.10 WAPA Bill Crediting Program Rider
- 8 • 14.11 Released Energy Rider

9
10 Q. WERE THE SCHEDULES YOU SPONSOR PREPARED BY YOU OR UNDER
11 YOUR DIRECTION?

12 A. Yes, they were.

13
14 Q. WHAT REQUIRED SCHEDULES ARE YOU SPONSORING?

15 A. In compliance with ARSD § 20:10:13:85, I am sponsoring a summary of present and
16 proposed revenues by class and a more detailed comparison of present and proposed
17 revenues by rate schedule and rate component. The summary comparisons are
18 included in Statement I in Volume 1.

19 I am also sponsoring OTP’s rate book revisions, which are contained in Volume 3.
20 The volume includes proposed final rate schedule sheets and black-lines showing the
21 changes. It also includes OTP’s proposed form service agreements for use with rates
22 for which customer agreements are appropriate.

23
24 Q. WHAT DOES THE SUMMARY COMPARISON INDICATE CONCERNING THE
25 TEST YEAR REVENUES BY CLASS UNDER THE PRESENT AND PROPOSED
26 RATES?

27 A. The 2009 test year revenues at present and proposed rates for the Electric Utility-
28 South Dakota jurisdiction are \$27,672,377 and \$30,428,330, respectively. The
29 difference between these present and proposed rate revenues is \$2,755,954. This
30 increase in rate revenues is the revenue deficiency.

1 Present rates are primarily those authorized in OTP's last electric rate case, Case
2 No. EL08-030. The test year sales for the test year were applied to both present and
3 proposed rates to obtain these Test Year revenues.
4

5 **II. RATE STRUCTURE OBJECTIVES**

6
7 Q. WHAT ARE THE RATE STRUCTURE OBJECTIVES THAT GUIDE OTP'S
8 PROPOSAL IN THIS CASE?

9 A. OTP identified the following rate structure objectives:

- 10 • The rate design should give the utility a reasonable opportunity to achieve its
11 revenue requirement. This implies rate structures that follow OTP's marginal
12 cost structure, thereby allowing revenues to track costs.
- 13 • The rate design should promote efficient use of resources, conservation and
14 use of renewables. This implies giving consumers price signals that reflect
15 marginal costs, including seasonal differences and, where reasonably possible,
16 time-of-day (TOD) differences.
- 17 • Any rate design changes should be gradual where necessary to avoid abrupt
18 bill impacts.
- 19 • The rate design should be based on structures that are reasonable and
20 nondiscriminatory. This includes minimizing cross-subsidies within rate
21 classes to the extent reasonably possible.
- 22 • The rate design should result in rates that are administratively feasible. This
23 includes taking metering and billing system constraints into account and
24 avoiding unnecessary complexity that might confuse customers.
- 25 • The rate design should preserve the attractiveness of load control/interruptible
26 riders as those riders provide substantial benefits to all OTP customers, as
27 described in the direct testimony of Mr. Thomas R. Brause.
28

1 **III. RATE DESIGN PROCESS: THE USE OF EMBEDDED AND**
2 **MARGINAL COSTS**

3
4 Q. PLEASE SUMMARIZE THE MAIN POINTS OF THIS PORTION OF YOUR
5 TESTIMONY.

6 A. This portion of my testimony makes two main points:

- 7 • Consistent with OTP’s rate design objectives I based the structure of the rate
8 schedules and riders covered by my testimony on the structure of OTP’s
9 marginal costs, tempered by the need to control bill impacts and maintain a
10 suitable inter- and intra-class relationship between the regular rates and riders
11 available to OTP’s customers.
- 12 • The proposed revenue requirement allocation for the rate schedules and riders
13 that are covered by my testimony was determined by applying the Equal
14 Percentage Marginal Cost (“EPMC”) methodology. This approach was used to
15 allocate the revenue requirement within major classes. The EPMC
16 methodology follows our rate structure objectives by improving the efficiency
17 of price signals and reducing cross-subsidies.

18
19 Q. WHAT PROCESS WAS USED TO DESIGN THE PROPOSED RATES AND
20 RIDERS COVERED BY YOUR TESTIMONY?

21 A. The basic approach was to use the structure and level of marginal costs for each
22 element of electric service, combined with the class revenue requirement allocations,
23 as described in the testimony of Mr. Peter J. Beithon. Next, the class revenue
24 requirements within the class level were allocated using the EPMC Methodology to
25 develop rates and riders that produce sufficient revenues, give improved price signals
26 to consumers, and have acceptable bill impacts.

27
28 Q. PLEASE DEFINE THE EPMC METHODOLOGY.

29 A. The EPMC methodology utilized by OTP efficiently allocates the embedded cost class
30 revenue requirement proposed by OTP in Mr. Peter Beithon’s direct testimony based
31 on marginal cost revenues. Marginal cost revenues for a rate class are determined by

1 multiplying the marginal cost times the rate class billing determinants. Exhibit
2 ___(DGP-1), Schedule 2 describes total marginal cost revenues by customer and rate
3 class. Schedule 2 also provides customer and rate class proposed allocations and
4 revenues.

5
6 Q. PLEASE PROVIDE AN EXAMPLE.

7 A. Lets assume that there is a customer class that has two rate classes. Assume further
8 that one of the rate classes provides 80 percent of the overall marginal cost revenues
9 for that customer class; and the other rate class provides 20 percent of the overall
10 marginal cost revenues. Finally assume that the embedded class cost revenue
11 requirement proposed by OTP is \$100,000. Applying EPMC, we would allocate 80
12 percent or \$80,000 of the embedded revenue requirement to the first rate class and 20
13 percent or \$20,000 to the second rate class.

14
15 Q. HOW IS THE MARGINAL COST STUDY USED IN THIS PROCEEDING?

16 A. The marginal cost study was used in two different areas; 1) the EPMC, which allocates
17 embedded revenue requirements to rate schedules within a class (previously
18 introduced and also described later in my testimony), and 2) to design rates that reflect
19 marginal costs.

20
21 Q. HOW ARE MARGINAL COSTS USED IN CONJUNCTION WITH EMBEDDED
22 COSTS?

23 A. Marginal Costs are used to adjust rates to the proposed revenue requirement, which is
24 based on embedded class cost of service and other modifications as described in Mr.
25 Beithon's direct testimony. By using marginal costs in conjunction with embedded
26 costs, the benefits of marginal cost price signals are retained. The benefits include
27 designing rates with seasonal and where possible, time of day differences.

28
29 Q. WHO DEVELOPED OTP'S MARGINAL COST STUDY?

1 A. OTP engaged Dr. Hethie Parmesano and her team at NERA to develop, with input
2 from OTP staff, a marginal cost study covering the period 2010-2014, applicable to
3 service in our three jurisdictions.
4

5 Q. PLEASE COMMENT ON THE MARGINAL COST STUDY AS PREPARED BY
6 DR. PARMESANO.

7 A. OTP closely reviewed Dr. Parmesano’s marginal cost study. The marginal cost study
8 reflects OTP’s planning and operating practices, regional market price data, and
9 system characteristics. Please see Exhibit __ (DGP-1), Schedule 4, which is the Otter
10 Tail Power Company Marginal Cost of Electric Service Study prepared in February
11 2010.
12

13 Q. WHAT MARGINAL COST CATEGORIES ARE EXAMINED IN THE STUDY?

14 A. The 2010 Marginal Cost Study examines the following marginal cost categories;
15 generation costs (energy and capacity), transmission, ancillary services, distribution,
16 and other costs (e.g. customer account costs, marginal losses).
17

18 Q. DID OTP FILE A MARGINAL COST STUDY IN ITS 2008 RATE CASE?

19 A. Yes. OTP filed and relied upon a marginal cost study in developing its rate design in
20 our most recent rate case (Case No. EL08-030). I will refer to it as the 2008 Marginal
21 Cost Study.
22

23 Q. WHEN COMPARING THE 2010 AND 2008 MARGINAL COST STUDIES, WHAT
24 ARE THE SALIENT GENERAL TRENDS FOR MARGINAL ENERGY &
25 CAPACITY COSTS YOU OBSERVED?

26 A. Since the 2008 Marginal Cost Study, the trends are as follows;
27 • Annual and seasonal combined energy and capacity costs have all declined. The
28 greatest decline occurred in the summer months.
29

- Annual and seasonal combined capacity costs (generation, transmission, and distribution) have increased on an annual basis, decreased in summer months, and increased the greatest in the winter months.
- Transmission capacity costs (NIT and NUC charges) have more than doubled.

Q. WILL THESE MARGINAL COST TRENDS IMPACT RATE DESIGN?

A. Yes. The rate designs will reflect marginal costs changes. For example, if the marginal costs relationships are fully retained, combined energy and capacity costs for rates without demand charges will see relative decreases in summer rates and increases in winter rates. All else being equal, rates with separate energy and capacity charges will be designed with the same energy charge relationships in the previous example but with decreases in summer demand charges and increases in winter demand charges.

Q. HAS THE EPMC METHODOLOGY BEEN ACCEPTED IN PRIOR RATE CASES?

A. Yes, the Commission and the North Dakota Public Utilities Commission approved OTP's use of the EPMC in OTP's recent general rate cases in each of those jurisdictions (SDPSC Docket No. EL08-030 and NDPSC Case No. PU-08-862). OTP introduced the EPMC Methodology in its pending rate case filing (Docket No. E-017/GR-10-239) with the Minnesota Public Utilities Commission.

Q. WHAT ARE THE BENEFITS OF OTP'S USE OF EPMC?

A. EPMC aligns with our rate structure objectives – efficiency and gradualism. The use of marginal costs promotes efficient use of electricity as the method sends efficient pricing signals. By using an allocation method that uses marginal costs, one can also allocate efficient revenue targets for rates within a class. The efficient revenue targets are the result of the product of test-year billing determinants multiplied by their associated marginal costs. In addition, efficient revenue targets may need to be adjusted to promote gradualism – a gradual approach which mitigates large bill impacts. Adjustments to the efficient revenue targets depend upon the level of impacts and amount of gradualism required to meet the rate structure objectives.

1 Q. DID OTP USE THE EPMC METHOD DIRECTLY TO DESIGN ALL RATES?

2 A. No. Recall that the EPMC method is used to allocate the proposed class revenue
3 requirement within the class level. OTP used the EPMC method in seven of the ten
4 customer classes that have more than one rate, except for the Lighting class. For this
5 class and the two remaining classes that have only one rate (the Farm and Water
6 Heating customer classes have only one rate class) we assigned the overall class
7 revenue requirement increase proposed by Mr. Beithon.

8

9 Q. WHY DID YOU USE THE CCOSS ALLOCATION PROCESS FOR LIGHTING
10 INSTEAD OF EMPC?

11 A. The EPMC method requires the use of marginal costs for the rate class billing
12 components. The Lighting customer class marginal costs together with their rate class
13 billing determinates have not yet been fully developed (OTP anticipates developing
14 that information in a future rate case).

15

16 Q. PLEASE DESCRIBE HOW OTP USED THE EPMC METHOD?

17 A. OTP utilized two EPMC approaches to allocate the revenue within the classes. Both
18 approaches have different levels of gradualism (mitigating the abruptness of rate
19 changes).

20

21 1. Method 1 – This method utilizes a strict application of EPMC within a class.
22 The purpose of this method is to set an “Equal Percent of Marginal Costs” to
23 two or more rates within a customer class in order to align the rates to follow
24 marginal cost price signals and minimize intra-class subsidies. This method
25 was used for the three (out of the ten) customer classes where the resulting
26 revenue requirement was reasonable without further adjustment.

27

28 For example, Method 1 was used in the Large General Service (“LGS”) class
29 because the result of the proposed increases from the EPMC method and those
30 proposed from the CCOSS were within a reasonable boundary. The CCOSS
31 proposed a 7.59 percent increase for the LGS class and the EPMC results

1 recommended a 7.97 percent increase for the Large General Service rate and a
2 5.78 percent increase for the Large General Service – Time of Day rate.
3 Method 1 was, therefore, used because both rate class increases were within a
4 reasonable boundary compared to each other and to the CCOSS class increase.
5

- 6 2. Method 2 – This method utilizes gradualism as it modifies the results from
7 strict application of EPMC within a class (see Method 1). This method was
8 applied to four out of the ten customer classes. The purpose of this method is
9 to also follow marginal costs price signals and minimize intra-class subsidies,
10 but in a gradual manner. It uses 50 percent of the difference between the
11 EPMC and the CCOSS proposed increases. Specifically, the target revenue for
12 a rate is 50 percent of the difference between (1) the overall CCOSS
13 percentage revenue increase proposed by Mr. Beithon for the class and (2) the
14 percentage revenue increase that would result from applying EPMC to each
15 rate within the class. This approach also recognizes the rate structure objective
16 of gradualism, and also takes into consideration the fact that the class as a
17 whole is receiving a revenue increase.
18

19 For example – the Residential Customer Class - Residential Demand Control
20 Service would see a revenue increase of 35.47 percent under strict application
21 of EPMC. The increase for the Residential class, based on the testimony of Mr.
22 Beithon, was 12.50 percent. Method 2 was used because both rate class
23 increases were not within a reasonable boundary compared to each other and to
24 the CCOSS class increase. Therefore the revenue target for this rate was set at
25 23.89 percent--half of the difference between 35.47 percent and 12.50 percent.
26

27 A summary of the proposed CCOSS assigned increase by classes to recover the
28 embedded revenue requirements and EPMC methods for allocation and levels of
29 gradualism within classes is shown in Table 1 below.
30
31

Table 1: Summary of EPMC Methods – Efficiency and Gradualism

CCOSS Customer Classes	CCOSS Proposed Increase	Proposed EPMC Method
Residential	11.41%	Method 2
Farms	15.00%	N/A
General Service	7.59%	Method 1
Large General Service	7.59%	Method 1
Irrigation	15.00%	Method 2
Lighting	10.00%	N/A
OPA	15.00%	Method 2
Controlled Service Water Heating	16.00%	N/A
Controlled Service Interruptible	19.00%	Method 1
Controlled Service Deferred Load	17.00%	Method 2

For further details on individual rate EPMC results, please see Exhibit ___(DGP-1), Schedule 2.

Q. IN ADDITION TO CHANGING RATES TO RECOVER THE REQUIRED REVENUE INCREASE IS OTP ALSO PROPOSING CHANGES TO SOME RATE STRUCTURES?

A. Yes. While we are proposing a number of improvements, our rate design change proposals in this case are more moderate as compared to our last rate case – both in number and in the level of changes. In OTP’s last electric rate case, Case No. EL08-030, it had been more than 20 years since the prior rate case and the need to make rate design adjustments was much larger.

Q. PLEASE SUMMARIZE THE RATE STRUCTURE CHANGES IN THIS PROCEEDING.

A. The table below summarizes the structures of rates and riders (Table 2) changed in this proceeding. In its last rate case, OTP made several structural rate design changes, most notably the elimination of declining blocks.

1

Table 2: Summary of Rate Structure Changes

Section	Rate Schedule Description	Proposed Rate Structure Change(s)
9.03	Farm Service	Eliminate OH/URD and kW size distinction for 3-phase
10.02	General Service - 20 kW or Greater	Change monthly minimum charge to include demand charge of at least 20 kW
10.03	General Service Time of Use	Change monthly minimum charge to include demand charge of at least 20 kW
11.04	Outdoor Lighting	Add new lighting service: MA-8PT
11.05	Municipal Pumping Service	Add Facilities Charge \$/kW
14.03	Large General Service Rider	Administrative charge applies to all rate options

2

3

4 Q. ARE THERE PROPOSED CHANGES NOT INCLUDED IN TABLE 2 (ABOVE).

5 A. Yes. Those changes will be noted in the next section of my testimony under the
6 appropriate individual rate proposal.

7

8 **IV. INDIVIDUAL RATE PROPOSALS**

9

10 Q. WHAT IS THE PURPOSE OF THIS SECTION OF YOUR TESTIMONY?

11 A. In this portion of my testimony I walk through each of the classes and individual rates
12 for which we are proposing rate design changes. I discuss our proposed rate changes,
13 the proposed rate’s relationship to marginal costs, and customer bill impacts.

14

15 **A. RESIDENTIAL CLASS**

16

17 Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE RESIDENTIAL CLASS?

18 A. There are two rate schedules in the Residential Class: Residential Service (Section
19 9.01) and Residential – Controlled Demand (Section 9.02).

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Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON PROPOSE IN HIS DIRECT TESTIMONY?

A. The proposed increase for the Residential Class is 12.50 percent.

Q. PLEASE LIST THE INTRA-CLASS INCREASES FOR EACH RATE SCHEDULE IN THE CLASS.

A. Residential Service received a proposed 11.41 percent increase, which was slightly lower than the class increase. Residential Demand Control Service received a proposed 23.98 percent increase, which was higher than the class increase. The intra-class allocations of the customer class revenue increase were determined as described in my previous EPMC testimony. Exhibit ___(DGP-1), Schedule 2 provides a summary of class and intra-class increases.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 9.01 RESIDENTIAL SERVICE RATE.

A. We begin with the class revenue requirements from the class allocations described in the direct testimony of Mr. Beithon. Then the intra-class revenue requirements were arrived at as described earlier in my testimony. For this rate we are proposing no rate design structure changes, only rate level adjustments. As discussed earlier, the 2010 Marginal Cost Study results will impact the proposed rate designs. The Residential Service Rate has energy and capacity costs combined into energy charges, which results in relative decreases in summer rates and increases in winter rates. Table 3 shows this result in the current and proposed rates.

This rate includes a monthly customer charge, a minimum bill equal to that customer charge, and two energy charge blocks, both seasonally differentiated, with one applying to the first 500 kWh's and the other as a declining block. As Table 3 below shows, the energy charges are set at 124 percent of marginal cost to meet the revenue requirement not satisfied by the customer charge and facilities charge. The proposed

energy charges, although purposely above marginal cost, provide an efficient and reasonable—but not optimal—price signal for residential customers.

The proposed customer charge is just under 66 percent of marginal cost. Marginal costs for facilities were developed based on design demand, tied to transformer and other customer-related distribution equipment.

Table 3: Comparison of Current and Proposed 9.01 Residential Rate and Marginal Costs

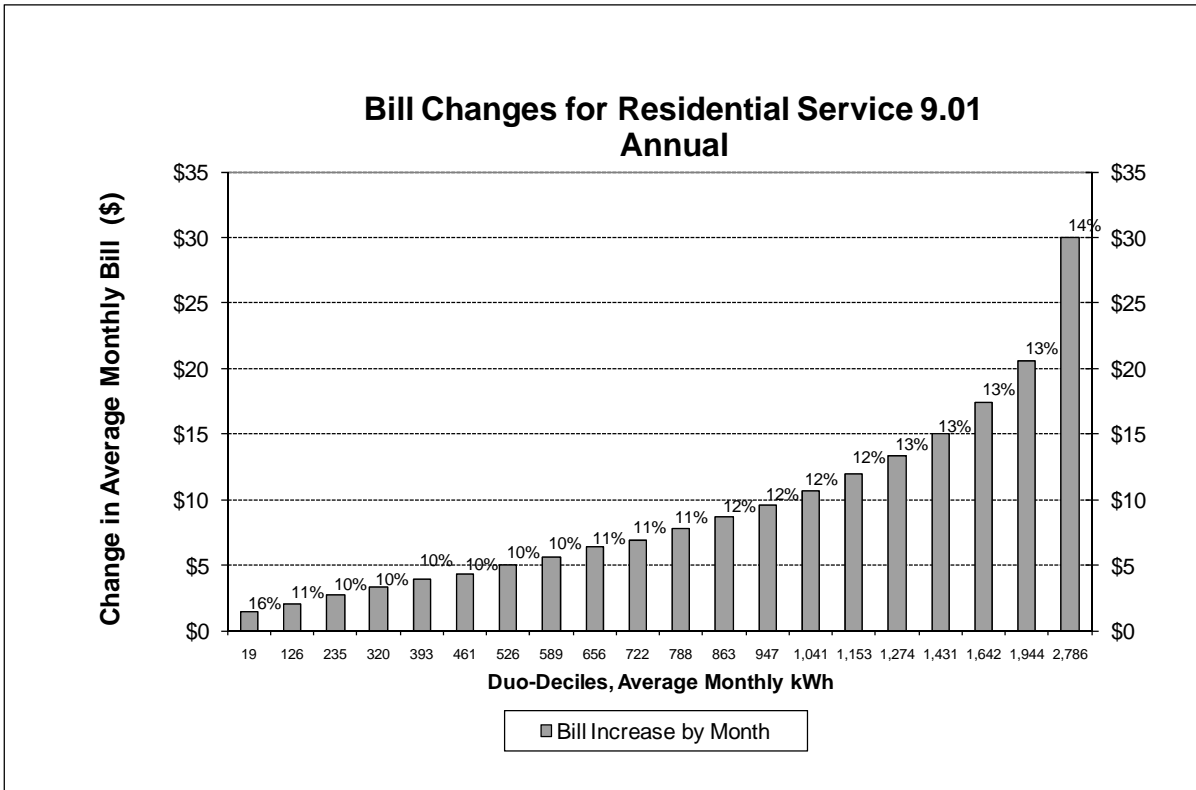
SD Residential Service 9.01	2009 Revenue	Proposed Rev	Increase			
	\$7,837,567	\$8,732,090	11.41%			
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh		
				All Year	Summer	Winter
Current Rate	\$7.00	Customer + Facilities		First 500	\$0.08626	\$0.08315
				Excess	\$0.07401	\$0.07198
			Water Heating Credit		-\$4.00	
Proposed Rate	\$8.00	Customer + Facilities	\$0.00	First 500	\$0.08858	\$0.09097
				Excess	\$0.08245	\$0.08538
Seasonal Fixed Charge	\$32.00		Water Heating Credit		-\$4.00	
Marginal Costs	\$12.19			All kWh	\$0.07112	\$0.07304
		< 5,000 kWhs	\$11.23			
		>= 5,000 kWhs	\$44.70			

Q. WHAT ARE THE BILL IMPACTS OF YOUR PROPOSED 9.01 RESIDENTIAL RATE?

A. To analyze bill impacts from each of OTP’s proposed rates, we computed the bills under current rates and under proposed rates for every OTP customer account in the class, using 2009 billing information (OTP’s test year). We then created bar charts showing the average monthly bill changes (dollar amounts and percentage) for duodeciles (20 equal segments) of customers, ordered by average monthly kWh use. Each bar represents 5 percent of customer accounts in the class. It is important to keep in mind that the smallest one or two bars probably include significant numbers of customers who were not on the system for the entire year, are seasonal customers, or are anomalies such as customers who shifted from one rate to another (or shifted load to a rider) during the year.

1 As the bar chart for residential customers below shows (Figure 1), the average
 2 monthly bill impacts are close to the requested increase for all customers. In other
 3 words, the bill impacts for all customers are primarily determined by the level of
 4 energy consumption. About 85 percent of residential customers will see average
 5 monthly impacts of less than \$15 – with 65 percent of all customers seeing average
 6 monthly impacts of about \$10 or less.

7 **Figure 1: Bill Impacts – 9.01 Residential Service**



- 9
- 10
- 11 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 9.02
- 12 RESIDENTIAL-CONTROLLED DEMAND RATE.
- 13 A. OTP’s proposed Residential Controlled Demand (RDC) rate retains the current rate
- 14 design. As shown in Table 4, the proposal continues with seasonal energy charges
- 15 which recover 100 percent of marginal cost, to match the embedded revenue
- 16 requirement for this class. The proposed rate retains seasonal demand charges. The
- 17 summer demand charge is still higher than the winter demand charge, with a greater

1 differential than the current rate design, reflecting OTP's higher marginal capacity
 2 costs. The current demand charges are levied with a 12-month ratchet, using only the
 3 winter season. Under the proposal, the demand charges follow the same ratchet as the
 4 current demand charges. The demand charges are at about 71 percent of marginal
 5 cost. The marginal cost relationship for the demand charges is different than the
 6 marginal cost relationship for the energy charges to accommodate a more gradual
 7 change to the higher marginal capacity costs.

8
 9 **Table 4: Comparison of Current and Proposed 9.02 Residential Controlled Demand and**
 10 **Marginal Costs**
 11

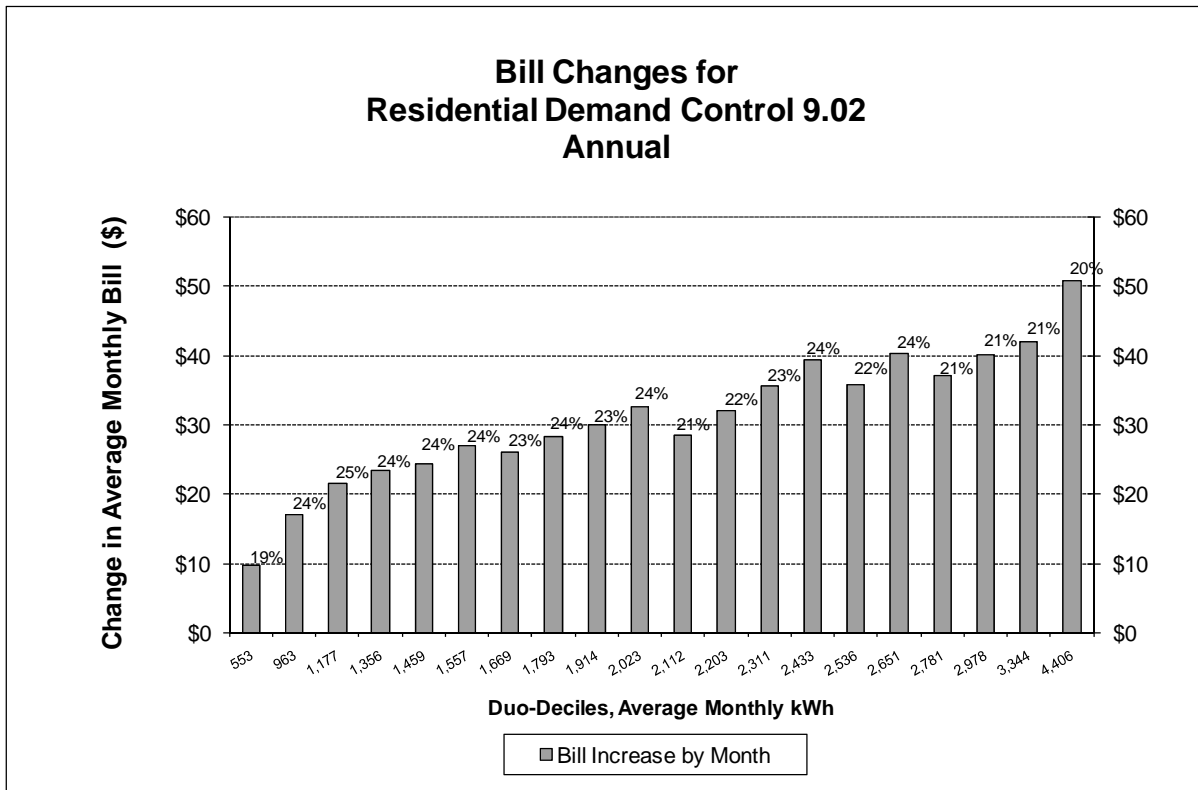
		Current Rev.	Proposed Rev.	Increase				
SD Residential Controlled Demand - 9.02		\$741,732	\$919,622	23.98%				
	Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW month	Charge per kWh		Demand Charge per kW per mo.		
				Summer	Winter	Summer	Winter	
Current Rate								
Seasonality - 12-month Demand Ratchet		\$12.00	Cust. + Demand Charge		\$0.04855	\$0.04905	per 12-mo. max \$4.71 \$4.31	
Proposed Rate								
	\$13.00	Cust. + Demand Charge		All kWh:	Summer \$0.05451	Winter \$0.05902	per 12-mo. max \$8.63 \$7.25	
			All Customers:	\$0.00				
Marginal Costs								
	\$15.93	Annual max. monthly kWh			Energy Only:		Capacity Only	
		<5000 kWh in all months:	\$11.23	Summer	Winter	Summer	Winter	
		>5000 kWh in any month:	\$44.70	\$0.05451	\$0.05902	\$12.16	\$10.22	

12
 13
 14 Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED 9.02 RESIDENTIAL
 15 CONTROLLED DEMAND RATE?

16 A. As Figure 2 shows, the bill impacts are fairly consistent in percentage terms, ranging
 17 from 19 to 25 percent, across groups of customers with increasing average monthly
 18 energy consumption. For comparison purposes, the test-year average customer usage
 19 on Residential Controlled Demand is greater than the Residential Service Customer by
 20 a factor of 2.36.

1

Figure 2: Bill Impacts – 9.02 Residential Controlled Demand Service



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B. FARM SERVICE CLASS

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6 Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON
7 PROPOSE IN HIS DIRECT TESTIMONY?

8 A. The proposed increase for the Farm Class is 15.00 percent.

9

10 Q. PLEASE LIST THE INTRA-CLASS INCREASES FOR EACH RATE SCHEDULE
11 IN THE CLASS.

12 A. There is only one rate schedule in the Farm class; therefore the Farm Service (Section
13 9.03) rate schedule received a 15.00 percent increase. Exhibit ___(DGP-1), Schedule 2
14 provides a summary of class and intra-class increases.

15 Q. WHAT RATE SCHEDULE ARE YOU PROPOSING FOR THE FARM CLASS?

16 A. OTP’s proposed Farm rate contains one rate structure change – the simplification of
17 the single and three-phase service facilities charges. As indicated in Table 5, all
18 customers on the rate have the same customer charge, but the rate incorporates a

monthly surcharge only for customers with three-phase service, (both overhead and underground). The energy charges for summer and winter are both set at approximately 114 percent of marginal cost. The customer and facility charges are set at 92 percent and no more than 52 percent respectively to meet the revenue requirement not satisfied by the energy charges.

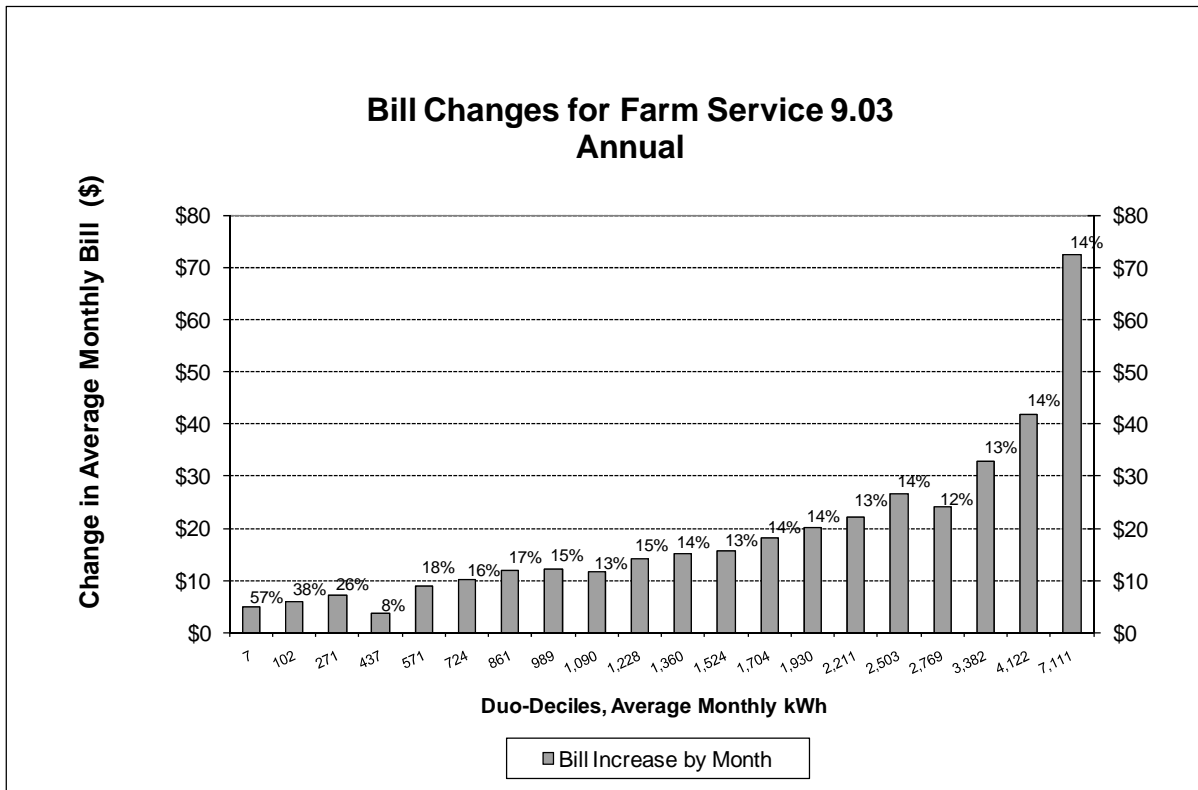
Table 5: Comparison of Current and Proposed 9.03 Farm Service and Marginal Costs

SD Farm Service 9.03			Current Rev	Proposed Rev	Increase			
			\$594,499	\$683,674	15.00%			
Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per kVA of Transformer		Energy per kWh				
				Summer	Winter			
Current Rates	\$8.00	Cust + Facility	3-Phase Surcharge per Mo.			0.07628	0.07405	First 1,600
			Overhead			0.07051	0.06878	Excess
			<25 kVA	\$3.85				
			25 kVA or more	\$4.49				
			Underground					
			<25 kVA	\$10.73				
			25 kVA or more	\$17.24				
Proposed Rate	\$13.00	Cust + Facility	3-Phase Surcharge per Mo.			\$0.08081	\$0.08299	First 1,600
			<25 kVA	\$5.00		\$0.07793	\$0.08036	Excess
			25 kVA or more	\$5.00				
Marginal Costs	\$14.07		Additional cost for 3-Phase per month			\$0.07112	\$0.07304	All
			Overhead					
			<25 kVA	\$9.61				
			25 kVA or more	\$11.23				
			Underground					
			<25 kVA	\$26.83				
			25 kVA or more	\$43.11				

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED FARM RATE?

A. The overall bill impacts, shown in Figure 3, are varied and range from about \$5 per month to under \$73 per month. Bill increases for the first 14 duo-decile segments (70 percent of the customers) average about \$20 per month or less, and percent increases average from 8 to 57 percent. The remaining 6 duo-decile segments (30 percent of the customers) have increases ranging between 12 and 14 percent.

Figure 3: Bill Impacts – 9.03 Farm Service



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C. GENERAL SERVICE CLASS

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6 Q. WHAT RATE SCHEDULES ARE YOU PROPOSING TO INCLUDE IN THE
7 GENERAL SERVICE CLASS?

8

A. There are three rates within the General Service Class: Small General Service (Under
9 20 kW) (Section 10.01); General Service (20 kW or Greater) (Section 10.02); and
10 General Service – Time of Use (f/k/a Commercial Time of Use) (Section 10.03).

11

12 Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON
13 PROPOSE IN HIS DIRECT TESTIMONY?

14

A. The proposed increase for the General Service Class is 7.59 percent.

15

16 Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE
17 SCHEDULE IN THE CLASS.

1 A. Small General Service (Under 20 kW) received a 7.75 percent increase, which was
2 slightly higher than the class increase. General Service (20 kW or Greater) received a
3 7.48 percent increase, which was slightly lower than the class increase. No increase
4 was assigned to General Service – Time of Use (f/k/a Commercial Time of Use).
5 There are no customers currently taking the General Service -- Time of Use service.
6 The intra-class allocations of the customer class revenue increase were determined as
7 described in my previous EPMC testimony. Exhibit ___(DGP-1), Schedule 2
8 provides a summary of class and intra-class increases.
9

10 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.01 SMALL
11 GENERAL SERVICE (UNDER 20 KW) RATE.

12 A. As shown in Table 6, OTP proposed energy charges for the Small General Service
13 (Under 20 kW) are set at 116 percent of marginal cost. The declining block remains,
14 but the differential is reduced. I also propose a customer charge, at about 77 percent of
15 marginal cost, and a minimum bill equal to the customer charge. Combined marginal
16 energy and capacity costs result in winter costs exceeding summer costs. Therefore
17 the proposed summer energy charge has been decreased and the winter energy charge
18 has been increased over current rates. A seasonal service has been added and is
19 discussed later in my testimony.
20
21

Table 6: Comparison of Current and Proposed 10.01 Small General Service (Under 20 kW) Rate and Marginal Costs

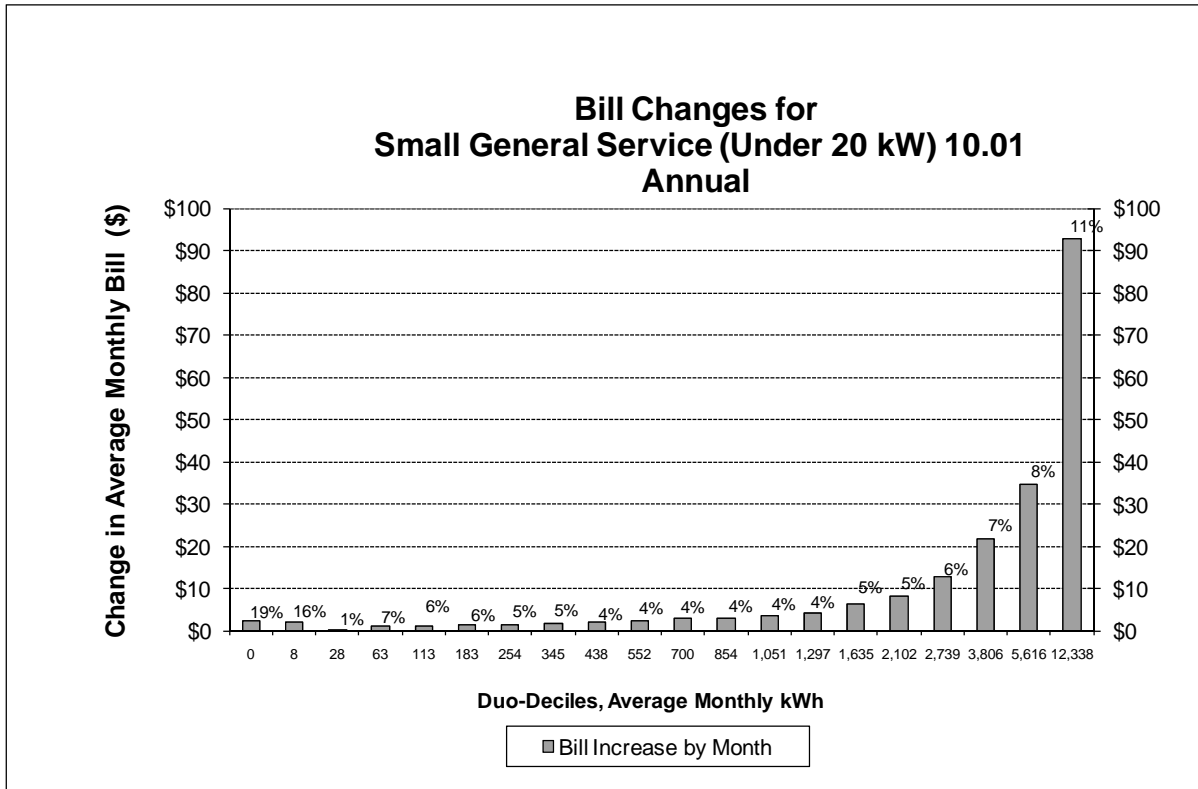
SD General Service Less than 20 kW - 10.01						
				Current Revenue \$2,568,700	Proposed Rev \$2,767,864	Increase 7.75%
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh		
				Summer	Winter	
Current Rate GS						
Secondary Service	\$12.00	Customer Charge	\$0.00	\$0.08683 \$0.07164	\$0.07886 \$0.06367	First 2,000 Excess
Primary Service	\$12.00	Customer Charge	\$0.00	\$0.08643 \$0.07130	\$0.07849 \$0.06337	First 2,000 Excess
Proposed Rate						
Secondary Service	\$13.00	Customer Charge	\$0.00	\$0.08269 \$0.07510	\$0.08492 \$0.07733	First 2,000 Excess
Primary Service	\$13.00	Customer Charge	\$0.00	\$0.07998 \$0.07242	\$0.08165 \$0.07409	First 2,000 Excess
Seasonal Fixed Charge	\$52.00					
Marginal Costs						
Secondary Service	\$16.98		\$5.35	\$0.07112	\$0.07304	
Primary Service	\$16.98		\$2.68	\$0.06879	\$0.07022	

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED 10.01 SMALL GENERAL SERVICE (UNDER 20 KW) RATE?

A. As shown in Figure 4 below, the average bill changes for the Small General Service (Under 20 kW) rate range from a 1 percent decrease to a 19 percent increase. About 80 percent of the class (represented by the first 16 duo-decile segments) will see an increase of \$8.35/month or less. The remaining 20 percent of the class (represented by the last 4 duo-decile segments) will see an increase from about \$13.00 up to \$93.00/month. In general, the customers in this rate class consume more energy in the winter than in the summer, resulting in an overall annual increase due to the higher winter energy rate discussed above. Customers that have higher consumption in the summer, versus the winter, will benefit more from the reduction in the summer energy charge.

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Figure 4: Bill Impacts – 10.01 Small General Service (Under 20 kW)



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- Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR 10.02 GENERAL SERVICE (20 KW OR GREATER).
- A. OTP’s proposed rate introduces a new seasonal demand charge, adjusted for reactive demand. The proposed seasonal demand charge provides an additional price signal beyond the facilities charge, which was introduced in our most recent rate case. As indicated in Table 7, the new seasonal demand charge was introduced at a gradual 10 percent of marginal capacity costs in order to mitigate bill impacts related to this change for lower load-factor customers. Customer charges were increased from \$10.00 to \$12.00, and at \$12.00 they represent about 62 percent of marginal costs. Increased facility charges, also set at 62 percent of marginal costs, are applied equally on a per kW basis and reflect each customer’s peak demand responsibility. The proposed energy charge is set at about 124 percent of marginal energy costs to meet the revenue requirement not satisfied by other charges. The proposed energy charges,

1 although purposely above marginal cost, provide an efficient and reasonable—but not
 2 optimal—price signal for this rate class. The minimum bill is the sum of the customer,
 3 facilities, and minimum demand charge.

4
 5 **Table 7: Comparison of Current and Proposed 10.02 General Service 20 kW or Greater**
 6 **and Marginal Costs**
 7

SD GS: Greater than or Equal to 20 kW - 10.02

Current Rev	Proposed Rev	Increase
\$3,732,945	\$4,012,302	7.48%

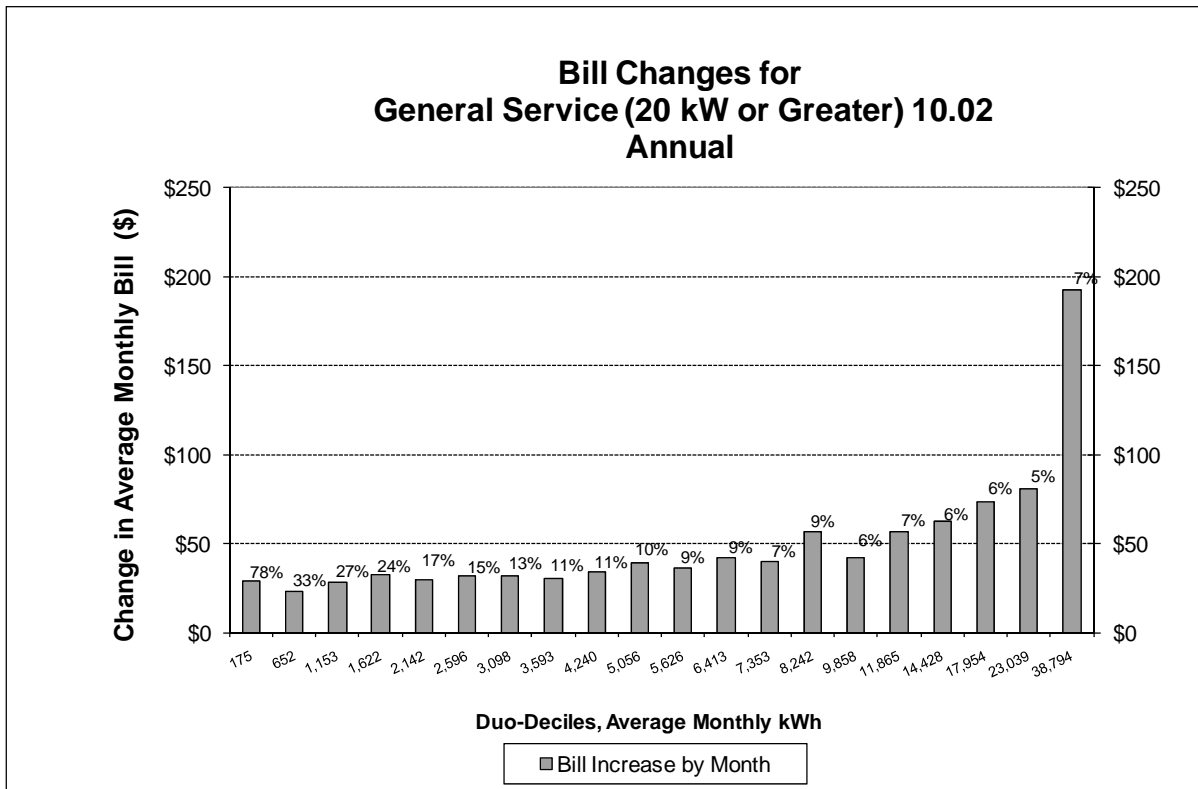
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
Current Rate							
Secondary	\$10.00	Cust.+ Facilities	\$0.52	\$0.07692	\$0.06982		
Primary	\$10.00	Cust.+ Facilities	\$0.38	\$0.07656	\$0.06946		
Proposed Rate							
Secondary	\$12.00	Cust. + Facilities Charge + minimum Demand	\$0.60	\$0.06735	\$0.07292	\$1.22	\$1.02
Primary	\$12.00	Cust. + Facilities Charge + minimum Demand	\$0.40 Minimum of 20 kW	\$0.06529	\$0.07031	\$1.17	\$0.97
Marginal Costs							
Secondary	\$19.51	Cust. + Facilities Charge + minimum Demand	\$0.97	\$0.05451	\$0.05902	\$12.16	\$10.22
Primary	\$19.51	Cust. + Facilities Charge + minimum Demand	\$0.65	\$0.05284	\$0.05691	\$11.67	\$9.71

8
 9
 10 Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED RATE CHANGES
 11 TO THIS RATE?

12 A. As shown in Figure 5 below, the average bill changes for customers on this rate range
 13 from 5 to 78 percent. The first four duo-decile segments have the highest bill impacts;
 14 likely due to low load factors which are sensitive to rates with demand charges. About
 15 75 percent of the customers have average monthly bill impacts within a range of about
 16 \$23 to \$43.
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Figure 5: Bill Impacts – 10.02 General Service 20 kW or Greater



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Q. ARE YOU MAKING ANY ADDITIONAL PROPOSALS FOR THE GENERAL SERVICE CLASS?

A. Yes. In addition, OTP’s proposal includes the Commercial Time of Use rate, which is proposed to be renamed as 10.03 General Service – Time of Use.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.03 GENERAL SERVICE-TIME OF USE RATE (F/K/A COMMERCIAL TIME OF USE RATE).

A. The General Service-Time of Use rate was first introduced in our last rate case. The proposed rate structure change for this rate schedule is a change in the monthly minimum charge to include a demand charge of at least 20 kW. In addition, demand charges are proposed to include adjustments for reactive demand. This approach is consistent with other OTP General and Large General Service rate schedules.

As outlined in Table 8, the proposed rate continues with seasonally differentiated charges, and sets the on-peak (“declared peak”) energy charges at full marginal cost (i.e. energy plus demand) expected in the hours likely to be defined as system peak hours. This rate structure continues to give a strong, efficient, and transparent price signal to customers during critical hours. The remaining energy and demand charges were set at, respectively, about 122 percent and 100 percent of marginal costs. The rate includes a customer charge, which is about 8 percent of marginal cost; and sets the minimum bill at the sum of the customer charge, the new facilities charge-at about 62 percent of marginal cost, and a minimum 20 kW demand (same concept as in the Large General Service, 10.04).

Table 8: Comparison of Current and Proposed 10.03 General Service Time of Use Rate and Marginal Costs

SD General Service Time of Use 10.03				Current Revenue	Proposed Revenue	Increase		
				\$0	\$0	0.00%		
	Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW month	Charge per kWh		Demand Charge per kW per mo.		
				Summer	Winter	Summer	Winter	
Current Rate								
Seasonal Energy and Demand with Peak, Shoulder, Off Peak	\$12.00	Cust+Fac.	\$0.52	*Declared	\$0.19699	\$0.12907	NA	NA
				Intermediate	\$0.06414	\$0.06506	\$2.45	\$2.84
				Off-peak	\$0.03638	\$0.03779	\$0.00	\$0.00
*Declared energy rates include some Capacity costs.								
Proposed Rate								
Seasonal Energy and Demand with Peak, Shoulder, Off Peak	\$19.00	Cust+Fac. +min. Demand	\$0.60	*Declared	\$0.20332	\$0.21624	\$0.00	\$0.00
				Intermediate	\$0.08153	\$0.07428	\$2.81	\$1.45
				Off-peak	\$0.03682	\$0.05536	\$0.00	\$0.00
*Declared energy rates include some Capacity costs.								
Marginal Costs				Marginal Energy		Marginal Capacity		
		Declared energy rates include 100% capacity costs.		\$0.20332	\$0.21624	Declared	\$0.00	\$0.00
				\$0.06711	\$0.06114	Interm.	\$2.81	\$1.45
	\$247.10		\$0.97	\$0.03031	\$0.04557	Off	\$0.07	\$0.86

Q. WHAT ARE THE BILL IMPACTS FROM THE PROPOSED 10.03 GENERAL SERVICE-TIME OF USE RATE?

A. There are no customers on this rate, therefore bill impacts are unknown. Customers willing to investigate this rate option would work with an OTP energy management representative to discuss the pros and cons of this unique rate offering.

1 **D. LARGE GENERAL SERVICE CLASS**

2
3 Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE LARGE GENERAL
4 SERVICE CLASS?

5 A. There are five rates within the Large General Service Class: Large General Service
6 (Section 10.04), Large General Service Time of Day (Section 10.05), Standby Service
7 (Section 11.01), Real-Time Pricing Rider (Section 14.02), and a Large General
8 Service Rider (Section 14.03). The Real-Time Pricing (“RTP”) Rider and Large
9 General Service (LGS) Rider is also discussed later in my testimony, in a section
10 where I discuss OTP’s riders.

11
12 Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON
13 PROPOSE IN HIS DIRECT TESTIMONY?

14 A. The proposed increase for the Large General Service Class is 7.59 percent.

15
16 Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE
17 SCHEDULE IN THE CLASS.

18 A. Large General Service (LGS) received a 7.97 percent increase, which was slightly
19 higher than the class increase. Large General Service Time of Day (LGS TOD)
20 received a 5.78 percent increase, which was lower than the class increase. There are no
21 customers taking service on the LGS Rider, Standby Service, or RTP Rider. The intra-
22 class allocations of the customer class revenue increase were determined as described
23 in my previous EPMC testimony. Exhibit ___(DGP-1), Schedule 2 provides a
24 summary of class and intra-class increases.

25
26 Q. PLEASE DESCRIBE YOUR OVERALL RATE DESIGN PROPOSAL FOR THE
27 LARGE GENERAL SERVICE CLASS.

28 A. OTP’s proposal for the Large General Service Class continues the current designs,
29 with adjustments to rate levels, and minor language changes. As I described earlier in
30 my testimony, the EPMC methodology is used to allocate the class revenue
31 requirement to the rates offered within the class.

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Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.04 LARGE GENERAL SERVICE RATE.

A. The proposed Large General Service (LGS) rate continues with single block seasonal demand and energy charges. These charges are based on marginal costs, but discounted to match revenues derived from the rate with the rate’s revenue requirement. Indicated in Table 9, seasonal energy charges are set at about 80 percent of marginal costs. Due to changes in marginal costs since the 2008 Marginal Cost Study, summer energy costs are proposed somewhat lower than winter energy costs. Seasonal demand charges are set at about 60 percent of marginal costs. The energy and demand charges are not set in proportion to marginal costs due to an increase in the level of demand charges. Summer demand charges still exceed winter demand charges, as they do under the current rate design, but the difference has been reduced under the proposed rate design. The proposed design approach reduces the impact of demand level increases, yet maintains the ratio between summer and winter marginal capacity costs. This allows the rate revenues to match the rate’s revenue requirements.

The facilities charge continues to vary by size of customer (in terms of maximum annual kW) and by voltage level. These charges are close to 46 percent of marginal cost. The customer charge is at 20 percent of marginal costs for secondary customers, and slightly lower (17 percent) for primary and transmission level customers. The minimum bill is set at the sum of the customer, facility, and demand charges. The proposed rate retains the minimum demand at 80 kW.

Table 9: Comparison of Current and Proposed 10.04 Large General Service and Marginal

SD Large General Service- Sec, Prim, Trans. 10.04

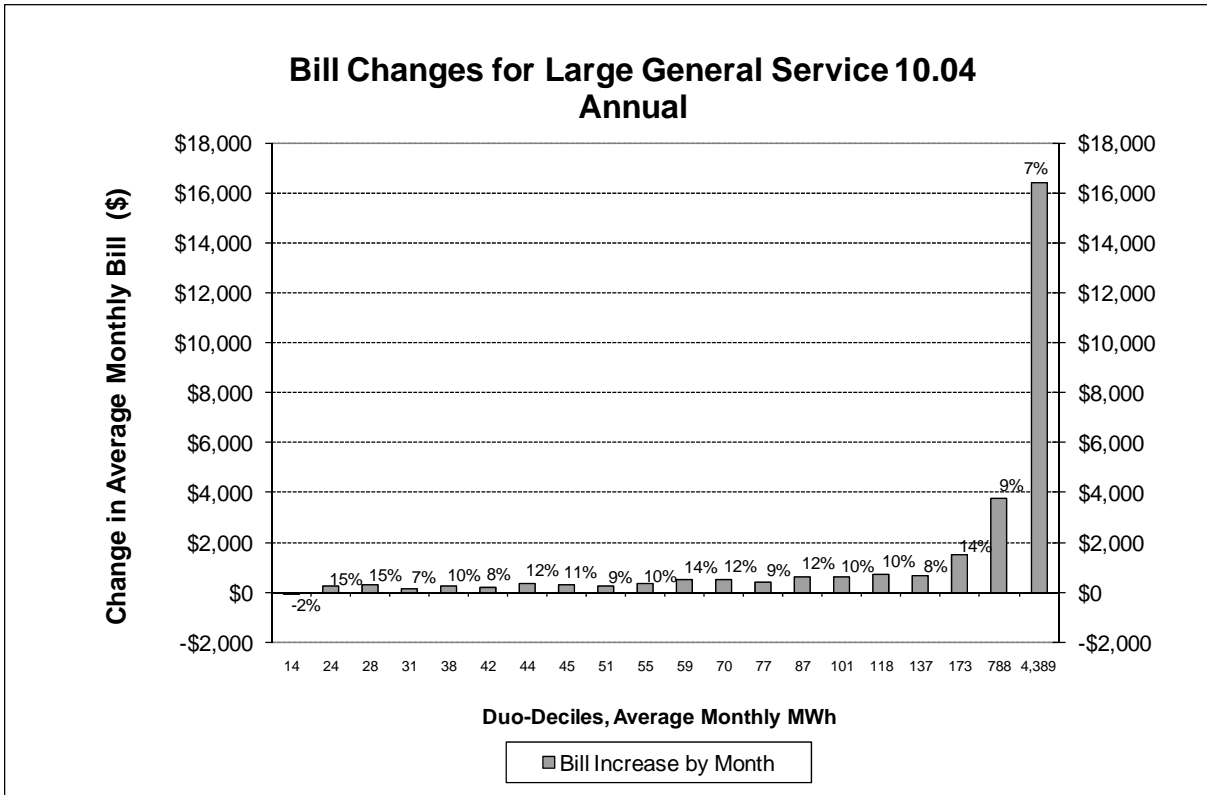
Present	Proposed	Increase
\$ 8,112,682	\$ 8,759,166	7.97%

	Customer Charge per month	Minimum Bill per month	Facilities Charge per annual max. kW (minimum 80 kW) per month	Energy Charge per kWh		Demand Charge per kW	
				Summer	Winter	Summer	Winter
SECONDARY							
Current Rate	\$40.00	Cust+Fac+Demand		\$0.04613	\$0.04661	\$7.06	\$2.85
		< 1000 kW:	\$0.30				
		> 1000 kW:	\$0.15				
Proposed - Secondary Customer, Facility, Flat Energy, Flat Demand	\$50.00	Cust+Fac+Demand		\$0.04386	\$0.04749	\$7.29	\$6.13
		< 1000 kW:	\$0.33				
		> 1000 kW:	\$0.24				
PRIMARY							
Current Rate	\$40.00	Cust+Fac+Demand	\$0.11	\$0.04594	\$0.04638	\$7.01	\$2.83
Proposed - Primary Customer, Facility, Flat Energy, Flat Demand	\$50.00	Cust+Fac+Demand	\$0.12	\$0.04251	\$0.04579	\$7.00	\$5.82
TRANSMISSION							
Current Rate	\$40.00	Cust+Fac+Demand	\$0.00	\$0.04475	\$0.04496	\$5.69	\$2.41
Proposed - Transmission Customer, Facility, Flat Energy, Flat Demand	\$50.00	Cust+Fac+Demand	\$0.00	\$0.04030	\$0.04305	\$5.42	\$5.02
Marginal Costs	\$295.92		\$0.00	\$0.05009	\$0.05350	\$9.04	\$8.37

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED 10.04 LARGE GENERAL SERVICE RATE?

A. Figure 6 below shows the average monthly bill impacts to the Large General Service Rate customers. The bill impacts for this class are in the range of 15 percent to negative 2 percent. About half of the customers on this rate will see an increase of about \$335 or less per month.

Figure 6: Bill Impacts – 10.04 Large General Service



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.05 LARGE GENERAL SERVICE -- TIME-OF-DAY RATE.

A. OTP's proposal for this rate is to continue with the current design, adjust rate levels, and to make minor language changes. For the same reasons described in my discussion of the Large General Service Rate (10.04), the energy and demand charges for all voltage levels were set disproportional to marginal costs (i.e. not set at the same percentage of marginal costs). Energy charges are set close to 82 percent of marginal energy costs and demand charges are set close to 60 and 65 percent of marginal costs. For all voltage levels, customer charges are set in the mid to upper-20 percent range and facilities charges are set at approximately 46 percent of marginal costs.

Table 10 describes the current and proposed rates for the Large General Service Time of Day (LGS TOD). Also included are current and proposed revenue and increases for the LGS TOD.

Table 10: Comparison of Current and Proposed 10.05 Large General Service Time of Day and Marginal Costs

SD Large General Service-Time-of-Day 10.05				\$1,694,817	2009 LGS TOD Rev.	5.78%	Increase	\$1,792,722	Proposed LGS TOD Rev.						
	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh						Demand Charge per kW					
				Summer			Winter			Summer			Winter		
				PK	SH	OP	PK	SH	OP	PK	SH	OP	PK	SH	OP
SECONDARY															
Current Rate	\$60.00	\$325 + Cust. + Fac.	\$0.30 < 1,000 kW \$0.15 >=1,000 kW	\$0.07298	\$0.05500	\$0.03115	\$0.06508	\$0.05219	\$0.03567	\$5.64	\$1.56	\$0.00	\$2.18	\$0.51	\$0.00
Rate 1	\$70.00	\$380 + Cust. + Facilities	\$0.33 < 1,000 kW \$0.24 >=1,000 kW	\$0.07442	\$0.05487	\$0.02478	\$0.06616	\$0.04999	\$0.03726	\$5.59	\$1.70	\$0.00	\$5.18	\$0.95	\$0.00
Marginal Costs	\$247.95		\$0.72 < 1,000 kW \$0.53 >=1,000 kW	\$0.09101	\$0.06711	\$0.03031	\$0.08091	\$0.06114	\$0.04557	\$9.27	\$2.81	\$0.07	\$7.91	\$1.45	\$0.86
PRIMARY															
Current Rate	\$60.00	\$325 + Cust. + Fac.	\$0.11	\$0.07264	\$0.05476	\$0.03104	\$0.06474	\$0.05193	\$0.03550	\$5.60	\$1.54	\$0.00	\$2.17	\$0.51	\$0.00
Rate 1	\$70.00	\$380 + Cust. + Facilities	\$0.12	\$0.07185	\$0.05316	\$0.02416	\$0.06355	\$0.04821	\$0.03605	\$5.37	\$1.63	\$0.00	\$4.99	\$0.83	\$0.00
Marginal Costs	\$295.92		\$0.25	\$0.08787	\$0.06501	\$0.02955	\$0.07772	\$0.05896	\$0.04409	\$8.90	\$2.70	\$0.07	\$7.52	\$1.37	\$0.82
TRANSMISSION															
Current Rate	\$60.00	\$325 + Cust. + Fac.	\$0.00	\$0.07061	\$0.05329	\$0.03034	\$0.06271	\$0.05033	\$0.03445	\$4.76	\$1.04	\$0.00	\$1.97	\$0.44	\$0.00
Rate 1	\$70.00	\$380 + Cust. + Facilities	\$0.00	\$0.06771	\$0.05035	\$0.02310	\$0.05941	\$0.04534	\$0.03408	\$4.35	\$1.07	\$0.00	\$4.31	\$0.71	\$0.00
Marginal Costs	\$295.92	Assumed to be owned by customer.		\$0.08281	\$0.06157	\$0.02825	\$0.0727	\$0.0555	\$0.0417	\$7.21	\$1.77	\$0.06	\$6.70	\$1.18	\$0.49

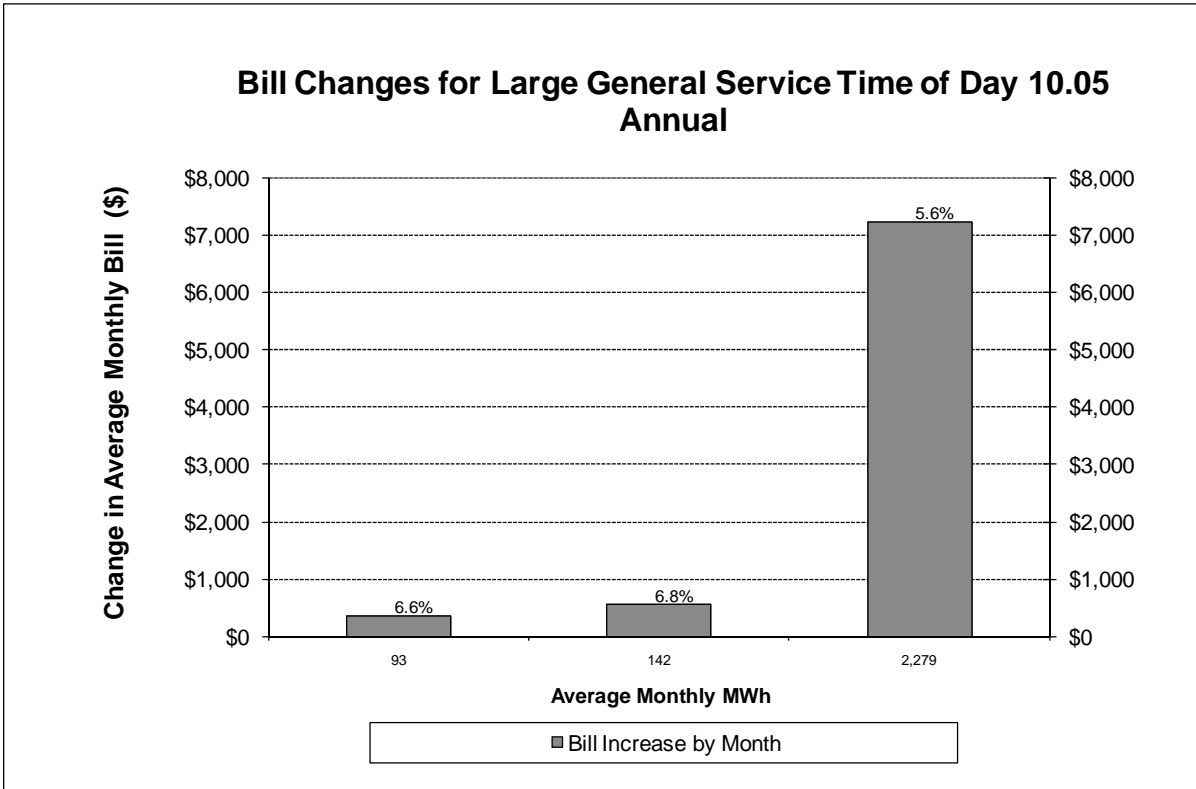
Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED 10.05 LARGE GENERAL SERVICE – TIME-OF-DAY RATE?

A. Figure 7 below shows the average monthly bill impacts for both the LGS TOD. The figure presents 3 individual customer impacts on an annual basis rather than 20 (duo-decile) segments to accommodate the small number of customers in this rate class. None of the customers take service on the Large General Service Rider (Section 14.03).

Because the impacts represented in Figure 7 are determined based on each customer’s historic usage patterns and because the purpose of time-of-use rates such as this one are to incentivize efficient customer usage patterns based on the price signals being sent by the particular rate design, it is reasonable to expect customers to respond to the price signals provide by the rate, resulting in actual customer impacts being less than represented here. Based only on historic usage patterns, the bill impacts reflected in Figure 7 vary significantly by usage level and pattern – depending upon the season, level, and frequency of use by each customer in the three different periods (on peak, shoulder, and off-peak). Impacts range from 5.6 to 6.6 percent.

1 Again, these impacts may be mitigated by customers responding to the price signals
2 inherent in the time-of-use rate design.

3
4 **Figure 7: Bill Impacts – 10.05 Large General Service Time of Day and**
5 **14.03 Large General Service Rider**



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8 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.01
9 STANDBY RATE.

10 A. In Table 11, OTP’s proposal for this rate continues with the current design by
11 adjusting rate levels. The updated design is based on OTP’s proposed Large General
12 Service-Time of Day Rate.

13 The proposed Standby Service rate provides three services under one rate
14 schedule. These services are Backup, Scheduled Maintenance, and Supplemental
15 Service:

- 16 • Backup Services is the energy and demand supplied by the utility during
17 unscheduled outages of a Customer’s generator.

- Scheduled Maintenance Service is the energy and demand supplied by the utility during scheduled outages of a Customer’s generator.
- Supplemental Service is the energy and demand supplied by the utility in addition to the capability of the on-site generator.

Table 11: Comparison of Current and Proposed Standby Service and Marginal Costs

South Dakota Standby Service				2009 Current Revenue \$0.00			Proposed \$0.00			Increase 0.00%				
	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge	Energy Charge per kWh						Demand Charge per kW		Reservation Charge per kW		
				PK	Summer SH	OP	PK	Winter SH	OP	Summer PK	Winter PK	Summer	Winter	
SECONDARY														
Current Rate	\$199.00	Cust. + Fac. + Res.	\$0.30	\$0.07298	\$0.05500	\$0.03115	\$0.06508	\$0.05219	\$0.03567	\$0.49076	\$0.32187	\$0.85069	\$0.09697	
				<1,000kW 1,00kW>										
Proposed	\$199.00	Cust. + Fac. + Res.	\$0.33	0.24	\$0.07442	\$0.05487	\$0.02478	\$0.06616	\$0.04999	\$0.03726	\$0.71375	\$0.73731	\$0.16772	\$0.05370
Marginal Costs	\$247.95		\$0.72	0.53	\$0.09101	\$0.06711	\$0.03031	\$0.08091	\$0.06114	\$0.04557	\$0.71375	\$0.73731	\$0.16772	\$0.05370
PRIMARY														
Current Rate	\$199.00	Cust. + Fac. + Res.	\$0.11	\$0.07264	\$0.05476	\$0.03104	\$0.06474	\$0.05193	\$0.03550	\$0.4868	\$0.3198	\$0.84590	\$0.09634	
Proposed	\$199.00	Cust. + Fac. + Res.	\$0.12	\$0.07185	\$0.05316	\$0.02416	\$0.06355	\$0.04821	\$0.03605	\$0.6838	\$0.7003	\$0.16042	\$0.05097	
Marginal Costs	\$295.92		\$0.25	\$0.08787	\$0.0650	\$0.02955	\$0.07772	\$0.05896	\$0.04409	\$0.6838	\$0.7003	\$0.16042	\$0.05097	
TRANSMISSION														
Current Rate	\$199.00	Cust. + Fac. + Res.	NA	\$0.07061	\$0.05329	\$0.03034	\$0.06292	\$0.05033	\$0.03445	\$0.3587	\$0.2869	\$0.81704	\$0.09254	
Proposed	\$199.00	Cust. + Fac. + Res.	\$0.00	\$0.06771	\$0.05035	\$0.02310	\$0.05941	\$0.04534	\$0.03408	\$0.6367	\$0.6433	\$0.14896	\$0.04678	
Marginal Costs	\$295.92		\$0.00	\$0.0828	\$0.06157	\$0.02825	\$0.0727	\$0.0555	\$0.0417	\$0.6367	\$0.6433	\$0.14896	\$0.04678	

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED 11.01 STANDBY SERVICE RATES?

A. OTP has no South Dakota customers currently taking Standby Service; therefore there are no bill impacts available.

E. IRRIGATION CLASS

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE IRRIGATION SERVICE CLASS?

A. There is only one rate schedule in the Irrigation Class, the Irrigation Service rate (Section 11.02). However there are two service options offered under this rate.

1 Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON
2 PROPOSE IN HIS DIRECT TESTIMONY?

3 A. The proposed increase for the Irrigation Class is 15.00 percent.
4

5 Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE
6 SCHEDULE IN THE CLASS.

7 A. There is only one rate schedule in the Irrigation class, with two rate options - therefore
8 Option 1 (Non-Time-Of-Use) received a 13.00 percent increase, which was lower than
9 the class increase. Option 2 (Time-of-Use) received a 29.44 percent increase, which
10 was higher than the class increase. The intra-class allocations of the customer class
11 revenue increase were determined as described in my previous EPMC testimony.
12 Exhibit ___(DGP-1), Schedule 2 provides a summary of class and intra-class
13 increases.
14

15 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.02
16 IRRIGATION SERVICE RATE.

17 A. OTP's proposed rate, shown in Table 12, maintains the current two service options,
18 both of which provide service from April 15 through November 1. The proposal for
19 both Option 1 and Option 2 retain the customer-specific facilities charges included in
20 the current rate.

21 The proposed Option 1 (Non-Time-Of-Use) continues with seasonal energy. The
22 energy charges are about 103 percent of marginal cost and the customer charge is
23 increased by \$1.00/month, which brings the customer charge to about 3 percent of
24 marginal costs.

25 The current Option 2 (Time-of-Use) rate consists of energy-based charges for off-
26 peak, intermediate, and on-peak or "declared" periods. The declared hours are defined
27 by OTP when the system is experiencing peak conditions. The proposal for Irrigation
28 Option 2 is to set the price for hours when OTP is experiencing peak conditions at 100
29 percent of marginal cost (energy plus capacity), thereby giving Option 2 irrigation
30 customers a transparent signal to curtail use during peak periods. These "on peak" or

“declared-peak” marginal costs are the average marginal costs, which vary by season, expected in the hours defined to be declared peak by OTP.

In the intermediate hours (which include the remainder of peak period hours and shoulder hours), energy and demand charges will apply. These charges are based on combined energy and capacity marginal costs, adjusted to about 117 percent. During the off-peak hours, only energy charges apply and are set at the same level of marginal costs as the intermediate peak. The proposed energy charges, although purposely above marginal cost, provide an efficient and reasonable—but not optimal—price signal in order to match the rate revenues with the rate’s revenue requirement. Like Option 1, the customer charge is increased by \$1.00 per month.

Table 12: Comparison of Current and Proposed 11.02 Irrigation Service Option 1 & 2 and Marginal Costs

SD Irrigation Option #1, Irrigation Option #2,		Current #1 Proposed #1		Current #2 Proposed #2					
		\$17,369	\$19,628	\$2,404	\$3,111				
		13.00% Increase		29.42% Increase					
Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh			Demand Charge per HP			
			Summer	Winter	Summer	Winter			
SECONDARY									
Current Rate	\$1.00	Customer Specific	\$0.06430		\$0.04695		N/A	N/A	
OPTION 1									
Rate 1 Option 1 - Seasonal Energy, Customer-specific facilities charge, Customer Charge	\$2.00	Cust.+Fac	Customer specific	\$0.07334		\$0.04841		N/A	
			Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak	
Current Rate	\$5.00	Cust.+Fac	\$ 0.18971	\$ 0.06896	\$ 0.03144	\$ 0.11343	\$ 0.06453	\$ 0.03137	
OPTION 2									
Rate 2 Option 2 - TOU energy including Capacity, Customer Charge, Customer-specific facilities charge	\$6.00	Cust.+Fac	Customer Specific	\$0.19993	\$0.08121	\$0.02229	\$0.22061	\$0.06942	\$0.02345
			Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak	
Marginal Costs	\$64.06		\$0.19993	\$0.06923	\$0.01900	\$0.22061	\$0.05918	\$0.01999	
			\$0.00000	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	

Q. WHAT ARE THE BILL IMPACTS FROM YOUR PROPOSED 11.02 IRRIGATION RATE?

A. As Figures 8 and 9 below reflect, bill impacts vary among irrigation customers. This is due to the fact that consumption levels and usage patterns (number of months of irrigation) vary widely among these customers. Like the Large General Service Time of Day (Figure 7), Figure 8 & 9 presents individual customer impacts rather than 20 (duo-decile) segments to accommodate the small number of customers in this rate

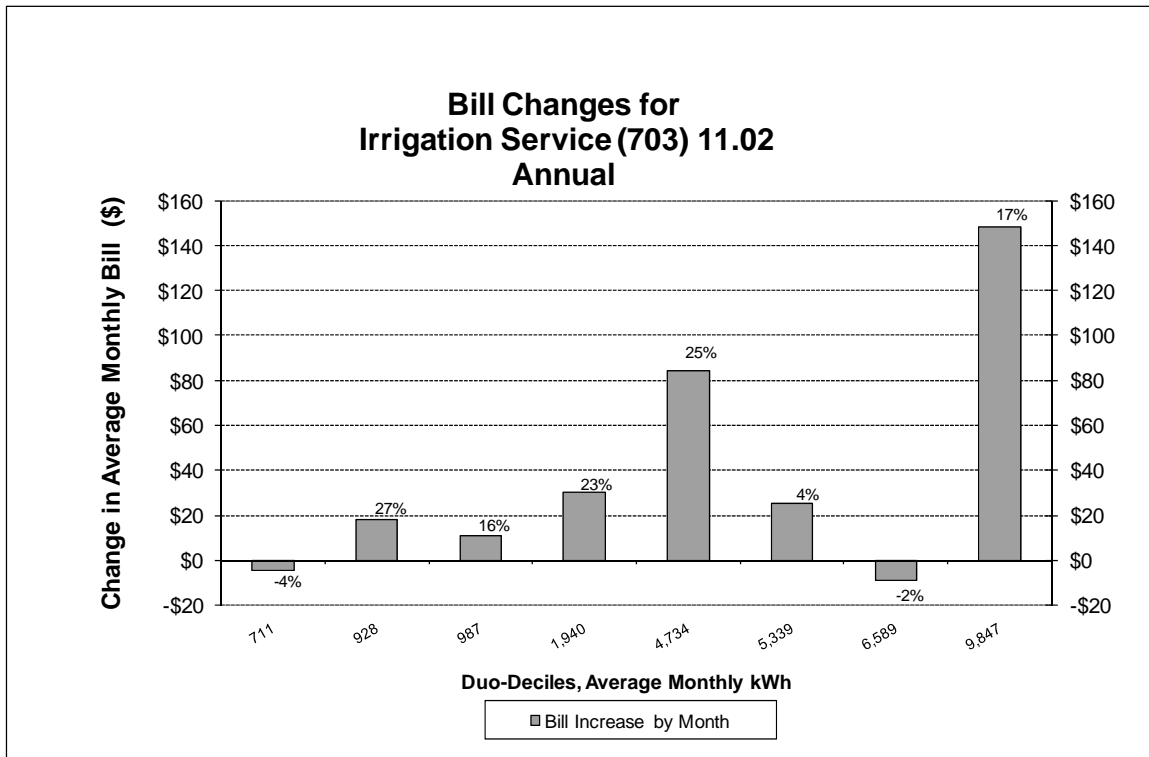
1 class. Option 1 impacts show 6 of the 8 customers with bill impacts of \$30 or less.
2 The impacts range from 25 percent to negative 4 percent. Option 2 has much greater
3 percent impacts for higher use customers due to the level of the proposed increase for
4 that option. The impacts range from 39 percent to negative 11 percent.

5 It should be noted when considering the Option 2 bill impact analysis that the bill
6 impacts for this Option have been determined based on customers' historic usage
7 patterns. Option 2 has time-of-use pricing components that are intended to incentivize
8 customer usage based on the price signals being sent by the particular rate design.
9 Therefore, it is reasonable to expect customers to respond to the price signals
10 incorporated into the rate, resulting in actual customer impacts that are less than
11 represented here. Specifically, declared peak prices were utilized in the rate impact
12 analysis even though customer usage during the historic period could not have
13 responded to the proposed rate's declared price signal. This does not imply the
14 customers would not respond, but it does simplify the analysis – foregoing potentially
15 complicated assumptions of customer reductions during these declared hours.

16
17 Customers will be advised by OTP energy management personnel, when
18 requested, to determine which Irrigation rate will provide them the best value for their
19 operating circumstances.
20

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Figure 8: Bill Impacts – 11.02 Irrigation (Option 1)

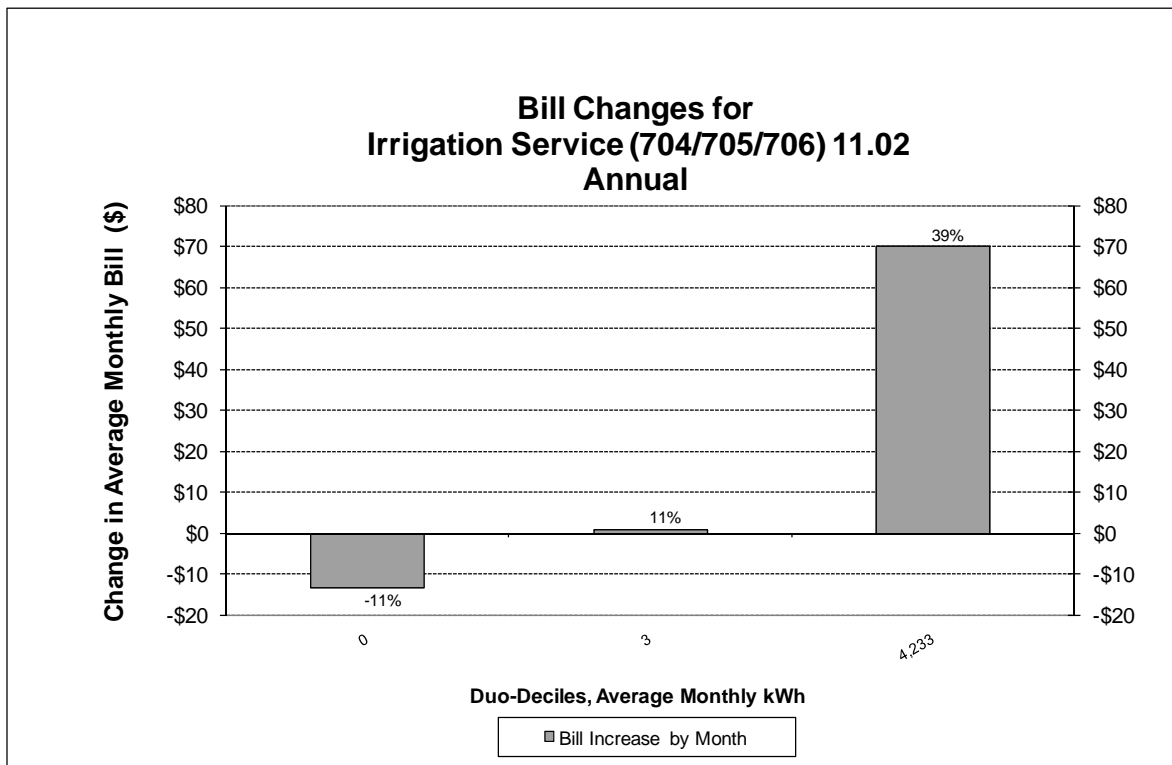


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Figure 9: Bill Impacts – 11.02 Irrigation (Option 2)



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F. OUTDOOR LIGHTING CLASS

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE LIGHTING SERVICE CLASS?

A. There are two rates in the Outdoor Lighting Class: Outdoor Lighting – Energy Only (Section 11.03) and Outdoor Lighting (Section 11.04).

Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON PROPOSE IN HIS DIRECT TESTIMONY?

A. The proposed increase for the Lighting Class is 10.00 percent.

Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE SCHEDULE IN THE CLASS.

A. Both Outdoor Lighting – Energy Only and Outdoor Lighting received the same increase of 10.00 percent as proposed by Mr. Beithon. Exhibit ___(DGP-1), Schedule 2 provides a summary of class and intra-class increases.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE PROPOSED 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE (RATE CODES 748 AND 749).

A. OTP’s proposal, shown in Table 13, introduces increased charges for the dusk to dawn energy service. The customer charge has increased but is still under marginal customer costs. The minimum bill was increased to match the increase in the customer charge. Instead of requiring a facilities charge, the energy charge per kWh hour was raised nearly 2 times marginal energy costs to meet the class revenue requirement.

Table 13: Comparison of Current and Proposed 11.03 Outdoor Lighting Energy-Only and Marginal Costs

SD Energy Only Lighting - 11.03				
	Current Revenue	Proposed Revenue	Increase	
	\$ 40,980	\$ 45,078	10.00%	
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh
Metered				
Current Rate	\$2.00	\$2.00	\$0.00	0.06097
Proposed Rate	\$2.50	\$2.50	\$0.00	0.06813
Marginal Costs	\$4.26		\$4.26	\$0.03722
Non-Metered				
Current Rate	Connected kW x	\$22.19	Current rate * 4100 hrs in year / 12 months	
Proposed Rate	Connected kW x	\$23.28	Current rate * 4100 hrs in year / 12 months	

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE.

A. The overall bill impacts for the rate are 10 percent.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.03 OUTDOOR LIGHTING RATE.

A. OTP's proposal introduces two different changes: proportional increased charges for all current lighting fixtures and the addition of a new Metal Halide lighting fixture.

Table 14 shows a summary of the Outdoor Lighting services and their current and proposed revenues and percent increase.

Table 14: 11.04 Outdoor Lighting – Summary of Services

STREET, AREA, and FLOOD LIGHTING

	Present Rate 2009	Proposed Rate	Proposed Increase
Street and Area Lighting	\$460,207	\$506,228	10.00%
Flood Lighting	\$96,946	\$106,641	10.00%
Closed-Non Standard	\$3,985	\$4,383	10.00%
Total	\$561,138	\$617,251	10.00%

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE NEW FIXTURE BEING ADDED TO THE 11.03 OUTDOOR LIGHTING RATE.

A. OTP’s proposal introduces a new a new outdoor lighting fixture to provide customers with another lighting choice. The metal halide fixture is a 100-watt light (MA8-PT) that attaches to the top of a pole (i.e. PT or pole-top) versus a light on an extended bracket arm, which is attached to the pole. The new MA8-PT is an improved replacement (higher lumens/watt) to the discontinued mercury-vapor pole-top fixture. Table 15 describes the rate development. This fixture offering will help to replace mercury vapor fixtures that OTP was recently required to discontinue offering. After January 1, 2008, all mercury vapor ballasts could no longer be manufactured or imported as part of the 2005 Energy Policy Act. OTP discontinued installing mercury vapor fixtures after August 1, 2008 as authorized in Case No. EL08-014.

Table 15: New Metal Halide Lighting Fixture Rate Development

A	B	C	D	E	F	G	H	I
Light Fixture Inputs				Monthly Unbundled Costs				
Fixture Total kW	Dusk to Dawn Hours/Year	Annual Lighting kWh	Proposed Energy Rate \$/KWh	Total Lighting Facilities & Hardware	Levelized Fixed Chg Facilities	O&M	Energy	Proposed MH8-PT \$/month
		A * B			E * 7.81% /12 Mo.		C * D	F+G+H
0.118	4100	483.8	\$ 0.07678	\$930.09	\$6.05	\$ 2.33	\$ 3.10	\$ 11.48

1 Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 11.04 OUTDOOR
2 LIGHTING RATE?

3 A. The bill impacts for each current lighting fixture are the same, 10 percent. The new
4 metal halide fixture has no bill impacts since it is a new service addition.
5

6 **G. OTHER PUBLIC AUTHORITY SERVICE CLASS**
7

8 Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE OTHER PUBLIC
9 AUTHORITY SERVICE CLASS?

10 A. There are two rates in the Other Public Authority Class: Municipal Pumping Service
11 (Section 11.05) and Civil Defense – Fire Siren Service (Section 11.06).
12

13 Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON
14 PROPOSE IN HIS DIRECT TESTIMONY?

15 A. The proposed increase for the Other Public Authority Service Class is 15 percent.
16

17 Q. PLEASE LIST THE INTRA-CLASS INCREASES FOR EACH RATE SCHEDULE
18 IN THE CLASS.

19 A. Municipal Pumping Service and Civil Defense – Fire Siren Service received increases
20 of 14.91 and 36.99 percent, respectively. Exhibit ___(DGP-1), Schedule 2 provides a
21 summary of class and intra-class increases.
22

23 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE MUNICIPAL
24 PUMPING SERVICE.

25 A. As shown in Table 16, OTP’s proposal introduces a new facilities charge, based on
26 demand (\$/kW), to replace the current facilities charge, which is based on energy
27 consumption (\$/kWh). The new proposed facilities charge (\$/kW) is similar to other
28 general service rate schedules and is introduced at 14 percent of marginal costs. The
29 energy charges are set at about 90 percent of marginal costs.

30 The customer charge is proposed at \$3.00 per month – about 12 percent of
31 marginal costs. The Monthly Minimum Bill is proposed to be the sum of the Customer

Charge plus the Facility Charge rather than the current rate's Minimum Bill, which is a fixed dollar per metering point.

Table 16: Current and Recommended 11.05 Municipal Pumping Rates and Marginal Costs

SD Municipal Pumping - 11.05

Current Rev \$234,358	Proposed Rev. \$269,309	Increase 14.91%
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**Comparison of Current Rate, Recommended Rate and Marginal Cost
Municipal Pumping**

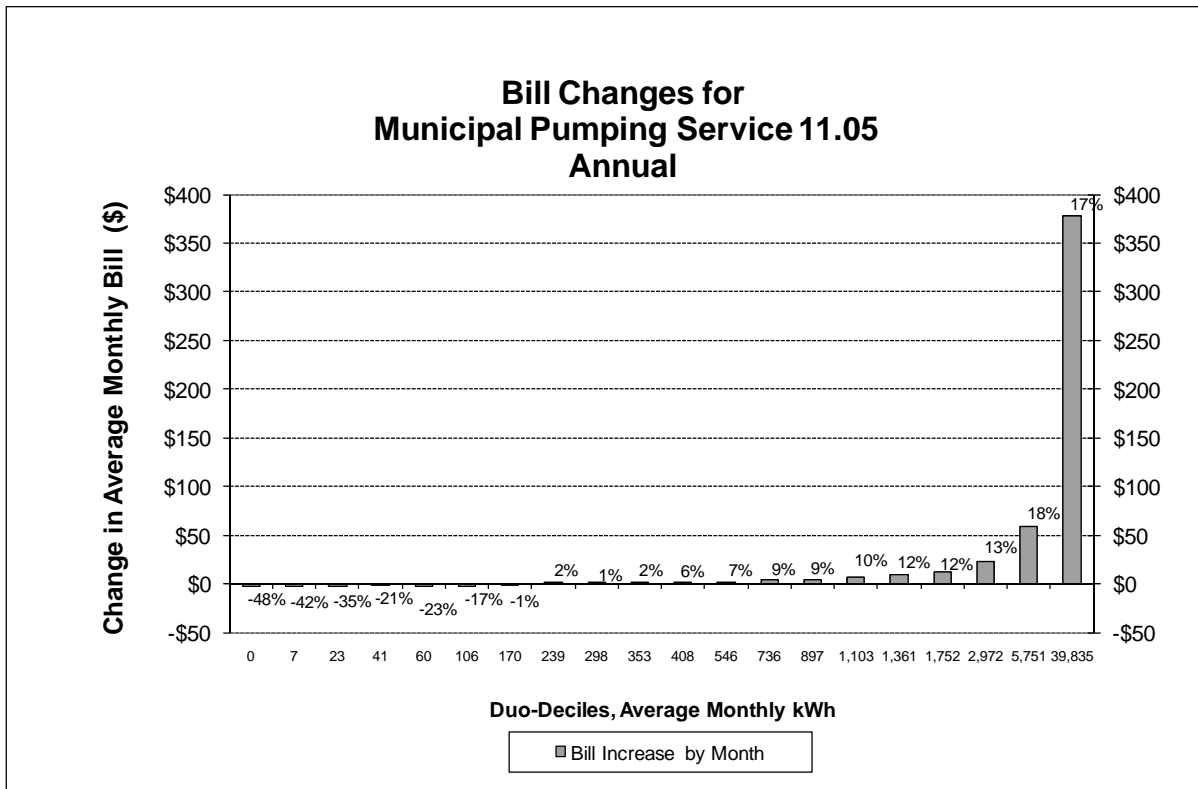
	Customer \$ per month	Minimum Bill \$ per month	Facilities Charge \$ per month		Summer \$ per kWh per month	Winter
Current Rate						
Secondary	\$2.00	Cust + Fac per metering pt.	\$4.00		\$0.06037	\$0.05472
Primary	\$2.00	Cust + Fac per metering pt.	\$2.68		\$0.06008	\$0.05444
Proposed Rate						
Secondary	\$3.00	Cust + Fac	per kW	\$0.14	\$0.06426	\$0.06600
Primary	\$3.00	Cust + Fac	per kW	\$0.09	\$0.06216	\$0.06345
Marginal Costs						
	\$24.51		Secondary	\$ 0.97		
			Primary	\$ 0.65		
				Energy & Demand		
All Season			Secondary	\$0.07112	\$0.07304	
			Primary	\$0.06879	\$0.07022	

Q. WHAT ARE THE BILL IMPACTS OF YOUR RECOMMENDED 11.05 MUNICIPAL PUMPING RATE?

A. Figure 10 reflects varied bill impacts, as the consumption levels of customers vary significantly under this rate. About 80 percent (16 duo-decile segments) of the customer's show bill impacts of less than \$10 per month. Of those 16 segments, 11 will experience bill impacts of about \$2.00 or less per month. Larger customers in the last 4 segments see larger increases in actual dollars, but those duo-decile segments represent customers with significantly more kWh consumption under the rate. On a percentage basis, the impact on those larger-usage customers ranges from 18 percent to negative 48 percent.

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Figure 10: Bill Impacts – 11.05 Municipal Pumping



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Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.06 CIVIL DEFENSE-FIRE SIREN SERVICE RATE.

A. The proposed Civil Defense-Fire Siren Rate, see Table 17, introduces a sizeable increase in the charge per horsepower. The proposed rate per horsepower is about 76 percent of combined energy and demand costs. The proposed Customer Charge is maintained at \$1.00 per month which also applies to the Monthly Minimum Bill provision. The Customer Charge is well above marginal costs to match the required revenue requirement.

Table 17: Current and Recommended 11.06 Civil Defense-Fire Sire Service

Current Rev.	Proposed Rev.	Increase
\$920.00	\$1,260.31	36.99%

SD Civil Defense Fire Sirens

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Charge per HP
SECONDARY				
Current Rate	\$1.00	Customer Charge	\$0.00	\$0.48731
Proposed Rate	\$1.00	Customer Charge	\$0.00	\$0.72848
Marginal Costs	\$0.13	Summer - Facilities/Energy per HP		\$0.96
		Winter - Facilities/Energy per HP		\$0.91

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED CIVIL DEFENSE-FIRE SIREN SERVICE RATE SCHEDULE?

A. The bill impacts are presented in a simple monthly bill comparison in Figure 11. The bill impacts range from 84 percent to a negative 3 percent, depending upon the size of the siren. The greatest annual dollar impact shown is \$3.89 per month.

Figure 11: Monthly Bill Impacts - 11.06 Civil Defense-Fire Siren Service

Monthly Bill Changes per Typical Siren Sizes

Siren HP	Monthly Impacts			
	Current Bill	Proposed Bill	Difference	% Change
2.5	\$ 2.75	\$ 2.82	\$ 0.07	3%
3	\$ 2.75	\$ 3.19	\$ 0.44	16%
5	\$ 2.75	\$ 4.64	\$ 1.89	69%
6	\$ 2.92	\$ 5.37	\$ 2.45	84%
10	\$ 4.87	\$ 8.28	\$ 3.41	70%
12	\$ 5.85	\$ 9.74	\$ 3.89	67%

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H. WATER HEATING SERVICE CLASS

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE WATER HEATING SERVICE CLASS?

A. There is only one rate in the Water Heating Class, the Water Heating – Controlled Service Rider (Section 14.01).

Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON PROPOSE IN HIS DIRECT TESTIMONY?

A. The proposed increase for the Water Heating Service Class is 16.00 percent.

Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE SCHEDULE IN THE CLASS.

A. Since there is only one rate schedule in the Water Heating Service Class, the Water Heating-Controlled Service Rider received a 16.00 percent increase. Exhibit ___(DGP-1), Schedule 2 provides a summary of class and intra-class increases.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 14.01 WATER HEATING-CONTROLLED SERVICE RIDER.

A. As Table 18 shows, the proposal for the Metered Water Heating Control Service (Rate Code 30-91) increases the customer charge to about 63 percent of marginal cost, retains the current method for calculating the Minimum Bill, and increases both seasonal energy charges to 126 percent of marginal cost in order to match rate revenues to the rate’s revenue requirement. The marginal costs of providing service to customers on this rate are lower than the marginal cost for standard rates because OTP controls the water heaters during high-cost periods.

1 **Table 18: Current and Proposed 14.01 Water Heating-Controlled Service Rider and**
 2 **Marginal Costs**
 3

SD Water Heating Control (Off-Peak) 14.01		Current Rev.		Proposed Rev.		
		\$413,540	\$479,707	16.0% Increase		
		Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh	
					Summer	Winter
Current	Customer Charge, Seasonal Energy	\$1.00	Cust. + Facilities	\$1.00	\$0.05540	\$0.05401
Proposed Rate	Customer Charge, Seasonal Energy	\$2.50	Cust. + Facilities	\$0.00	\$0.06067	\$0.06487
Marginal Costs		\$4.00		\$5.62	\$0.04806	\$0.05139

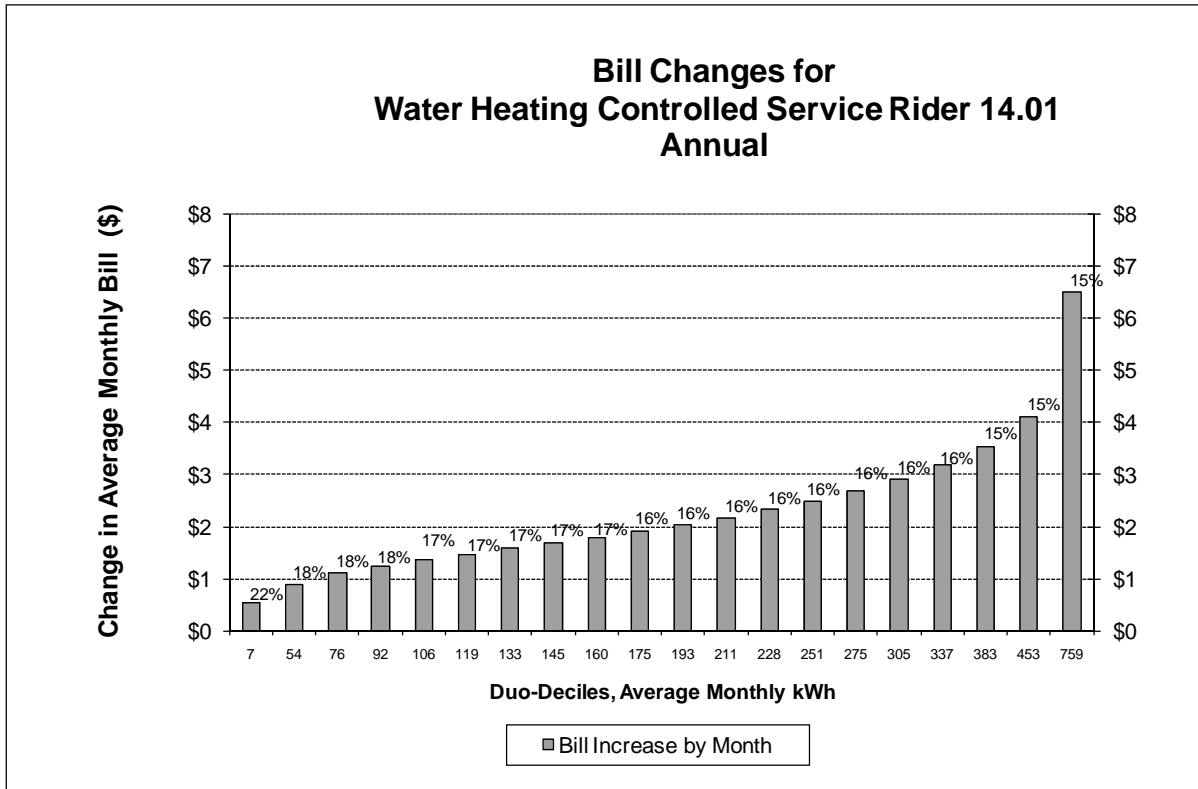
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 6 The Water Heating Control Service Credit (Rate Code 192) is essentially a direct
 7 load-control program similar to direct load-control of central air conditioners. Under
 8 the rate, in exchange for allowing the Company to interrupt the water heating service
 9 during high-cost periods, the Company compensates the customer in the form of a bill
 10 credit. The credit remains unchanged at \$4 per month.

11
 12 Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 14.01 WATER
 13 HEATING-CONTROLLED SERVICE RIDER?

14 A. Figure 12 shows the Metered Water Heating Control Service (Rate Code 30-91)
 15 monthly bill impacts. The average monthly bill impacts are modest – with an increase
 16 less than \$4.00 for 90 percent of customers; the remaining 10 percent of customers
 17 will see an increase of less than \$7.00. There are no bill impacts for the Water Heating
 18 Control Service Credit (Rate Code 192), not shown in Figure 13, because the \$4 per
 19 month credit will continue to reduce the customers’ standard firm service total bill by
 20 \$4 per month. The impact of the \$4.00 credit is reflected in the duo-deciles for the
 21 appropriate firm service rates (e.g. Residential Service, Figure 2).

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Figure 12: Bill Impacts from Proposed 14.01 Water Heating –Controlled Service Rider



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I. CONTROLLED SERVICE - INTERRUPTIBLE

Q. WHAT RATE SCHEDULES ARE YOU TO INCLUDE IN THE CONTROLLED SERVICE - INTERRUPTIBLE CLASS?

A. There are two current rates in the Interruptible Service Class: Controlled Service – Interruptible Load (CT Metering, Section 14.04) Rider; and Controlled Service – Interruptible Load (Self-contained metering, Section 14.05); OTP proposed in its last rate case a new option for Controlled Service – Interruptible Load (CT Metering – Option 2, Section 14.04). This option continues to allow heating system-associated motor load, up to 5 percent of the metered maximum demand, to be operated during periods of control. The rate accounts for the operation of the motor. This option is in contrast to the current option (Option 1) which only allows motor load used to distribute heat to be connected separately to the appropriate General Service (firm)

1 rate schedule. By continuing this option, customers will have more flexibility in how
2 they configure the motor load that distributes their heat.

3
4 Q. WHAT WAS THE PROPOSED CUSTOMER CLASS REVENUE INCREASE
5 ACCORDING TO MR. BEITHON'S TESTIMONY?

6 A. The proposed increase for the Controlled Service - Interruptible Class is 19.00 percent.

7
8 Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE
9 SCHEDULE IN THE CLASS.

10 A. Controlled Service – Interruptible Load (CT Metering) Rider received a 21.68 percent
11 increase, which was higher than the class increase. Controlled Service – Interruptible
12 Load (Self-contained metering) a 17.84 percent increase, which was lower than the
13 class increase. The intra-class allocations of the customer class revenue increase were
14 determined as described in my previous EPMC testimony. Exhibit ___(DGP-1),
15 Schedule 2 provides a summary of class and intra-class increases.

16
17 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 14.04
18 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER,
19 OPTION 1.

20 A. The proposed Controlled Service – Option 1 Rider maintains the current customer
21 charge and facilities charge based on a \$/kW basis to better reflect facilities costs by
22 customer size. Table 19 shows the customer charge at 25 percent of marginal costs,
23 facilities charge rate is at about 14 percent of marginal costs while the energy rate is at
24 about 84 percent of marginal costs. The penalty rate for energy consumed during
25 control periods is based on the total marginal cost over a year and separated into
26 summer and winter seasons. The penalty rate per kWh has been calculated based on
27 the hourly marginal costs during periods usage would be controlled. Fundamentally,
28 the penalty rate charges customers for unauthorized use during control periods.

29
30

Table 19: Current and Proposed – Option 1 Controlled Service-Interruptible Load (CT Metering) Rider 14.04 and Marginal Costs

SD LDF CT Metering - Option 1 14.04				Current Rev.	Proposed Rev	Increase
				\$251,251	\$305,729	21.68%
Controlled Service - Interruptible - (assumes all customers have CT metering)						
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge	Energy Charge per kWh		
SECONDARY				Summer	Winter	
Current Rate	\$3.00	Cust. + Facilities	\$0.08 per kW	All kWh	\$0.03185	\$0.03047
				Penalty kWh	\$0.39031	\$0.12325
Proposed Rate	\$5.00	Cust. + Facilities	\$0.12 per kW	All kWh	\$0.03694	\$0.04004
				Penalty kWh	\$0.14991	\$0.15270
Marginal Costs	\$20.01	<300 kW	\$0.85	All kWh	\$0.04415	\$0.04786
		>=300 kW	\$0.59	Penalty kWh	\$0.18684	\$0.19274

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 14.04 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER, OPTION 2.

A. As shown in Table 20, the proposed Controlled Service – Option 2 Rider combines rate designs of Option 1 and Large General Service (10.04). As described earlier, this option allows customers to design their heating systems so that motor load may operate during control periods, provided that motor load is limited to 5 percent of the metered maximum demand. The rate includes firm energy and demand charges to account for the motor load operating during control periods. It also includes discounted energy and capacity charges to reflect the controlled loads. During control periods, the heating load is curtailed, the motor load continues to operate and the demand level is recorded and charged a firm demand charge per the Large General Service (10.04). Energy charges are set at about 89 percent of marginal costs.

The penalty rate described above in reference to Option 1 also applies to Option 2 for unauthorized use during control periods.

Table 20: Proposed Option 2 - Controlled Service-Interruptible Load (CT Metering) Rider Section 14.04 and Marginal Costs

SD LDF CT Metering - Option 2 - 14.04

\$ - \$ - 0%

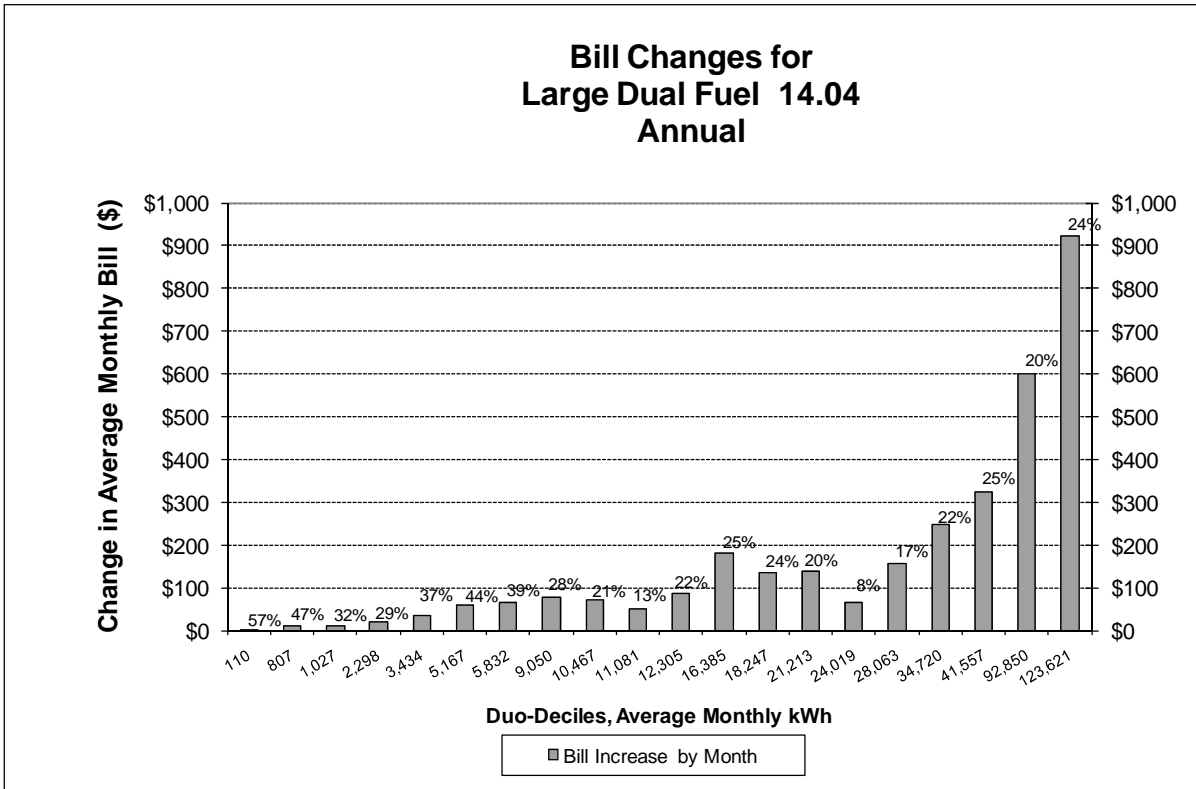
Controlled Service-Interruptible (assumes all customers have CT metering)

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge	Energy Charge per kWh		Demand Charge per kW	
				Summer	Winter	Summer	Winter
SECONDARY							
Current Rate	\$4.00	Customer + Facilities charge	per annual max. kW per month \$0.08	\$0.03446	\$0.03298	\$7.06	\$2.85
Rate 1 Seasonal Energy, kW Facilities All kWh	\$6.00	Customer + Facilities charge	per annual max. kW per month \$0.12	\$0.03939	\$0.04270	\$7.29	\$6.13
Marginal Costs	\$20.01	<300 kW >=300 kW	\$0.85 \$0.59	\$0.04415 (Plus 5% firm energy charge)	\$0.04786	LGS Sec. kW Charge	

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 14.04 CONTROLLED INTERRUPTIBLE LOAD (CT METERING) RIDER – OPTION 1 AND THE NEW OPTION 2?

A. The bill impacts, below in Figure 13, from the proposed rate (Option 1) range from 8 to 57 percent. Seventy-five percent of the customers will see impacts from over \$3 up to about \$180 per month. The relatively high percentage impacts are due to the proposed class cost allocations which are described in the direct testimony of Mr. Beithon. Since 14.04 Controlled Service-Interruptible Load (CT Metering) Rider Option 2 is a relatively new service, no customers have taken service on this rate option.

1 **Figure 13: Option A Bill Impacts from Proposed 14.04 Controlled Service-Interruptible**
 2 **Load (CT Metering) Rider**
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 6 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 14.05
 7 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (SELF-CONTAINED
 8 METERING) RIDER.

9 A. OTP's proposal for this rate, illustrated in Table 21, maintains the customer charge,
 10 continues a fixed monthly facilities charge, and sets both seasonal energy charges at
 11 88 percent of marginal costs. The penalty for energy used during a control period is
 12 intended to deter customers from unauthorized use during control periods. The penalty
 13 rate plus the seasonal energy rate are equal to 100 percent of marginal costs.

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2
3

Table 21: Current and Proposed 14.05 Controlled Service-Interruptible Load (Self-Contained) Rider and Marginal Costs

SD Small Dual Fuel - Self Contained Metering - 14.05		Current Revenue	Proposed Rev	Increase
		\$580,567	\$684,135	17.84%

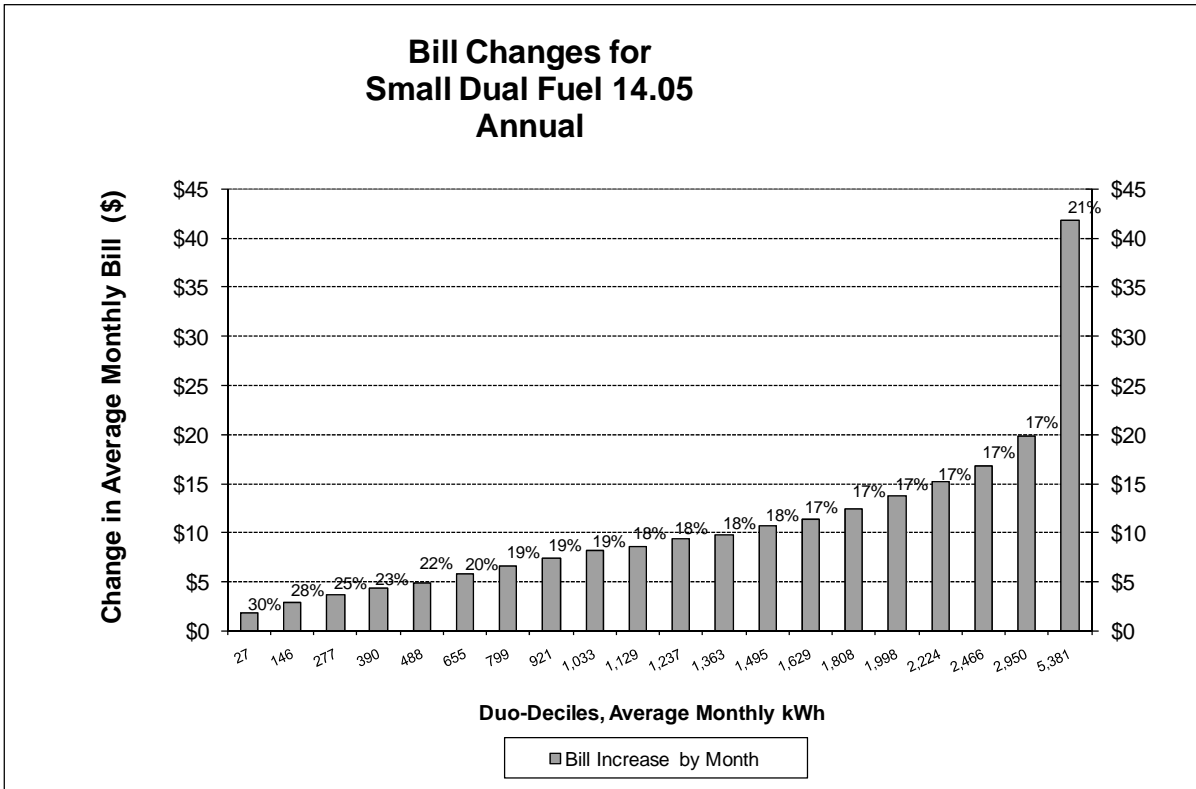
Controlled Service - Interruptible - SDF, Self-Contained: (assumes all customers do not have CT metering)							
SECONDARY	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per customer per month		Energy Charge per kWh		
					Summer	Winter	
Current Rate	\$2.00	Cust. + Facilities Charge	\$3.50		All kWhs	\$0.03836	\$0.03595
					Penalty kWhs	\$0.38031	\$0.12382
Proposed Rate	\$2.00	Cust. + Facilities Charge	Fixed Facilities	\$5.00	All kWhs	\$0.04117	\$0.04503
					Penalty kWhs	\$0.15876	\$0.17120
Marginal Costs	\$5.82		<5000 kWh in all months	\$11.23	All kWhs	\$0.04698	\$0.05139
			> 5000 kWh in any month	\$44.70	Penalty kWhs	\$0.19993	\$0.21624

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Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 14.05 CONTROLLED INTERRUPTIBLE LOAD (SELF-CONTAINED) RIDER?

A. As Figure 14 shows, the percentage bill impacts are very uniform across all levels of consumption. About 95 percent of the class customers have bill impacts under \$20 per month – with 60 percent of the class customers seeing under \$10 per month impacts. The remaining 5 percent of customers will see average increases of over \$40 per month.

1 **Figure 14: Bill Impacts from Proposed 14.05 Controlled Service-Interruptible Load**
 2 **(Self-Contained) Rider**
 3



4
5
6 **J. DEFERRED LOAD SERVICE CLASS**

7
8 Q. WHAT RATE SCHEDULES ARE YOU PROPOSING TO INCLUDE IN THE
9 DEFERRED LOAD SERVICE CLASS?

10 A. There are two rates in the Deferred Load Service Class: Controlled Service – Deferred
11 Load Rider (Section 14.06) and Fixed Time of Service Rider (Section 14.07).

12
13 Q. WHAT CUSTOMER CLASS REVENUE INCREASE DOES MR. BEITHON
14 PROPOSE IN HIS DIRECT TESTIMONY?

15 A. The proposed increase for the Deferred Load Service Class is 17.00 percent.
16
17

1 Q. PLEASE LIST THE PROPOSED INTRA-CLASS INCREASES FOR EACH RATE
2 SCHEDULE IN THE CLASS.

3 A. Controlled Service – Deferred Load Rider received a 19.79 percent increase, which
4 was higher than the class increase. Fixed Time of Service Rider received an 8.78
5 percent, which was lower than the class increase. The intra-class allocations of the
6 customer class revenue increase were determined as described in my previous EPMC
7 testimony. Exhibit ___(DGP-1), Schedule 2 provides a summary of class and intra-
8 class increases.

10 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 14.06
11 DEFERRED LOAD SERVICE RIDER.

12 A. The proposed Deferred Load Service Rider, shown in Table 22, increases the customer
13 charge from \$2.50 to \$3.00 per month and adds a \$1.00 to the current flat facilities
14 charge to total \$4.00 per month. Seasonally differentiated energy charges in the
15 proposed design were adjusted to about 104 percent of marginal costs to account for
16 the change in the facilities charge.

17 The penalty for energy used during a control period is intended to deter customers
18 from unauthorized use during control periods.

20 **Table 22: Current and Proposed 14.06 Deferred Load Rider Rates and Marginal Costs.**

21

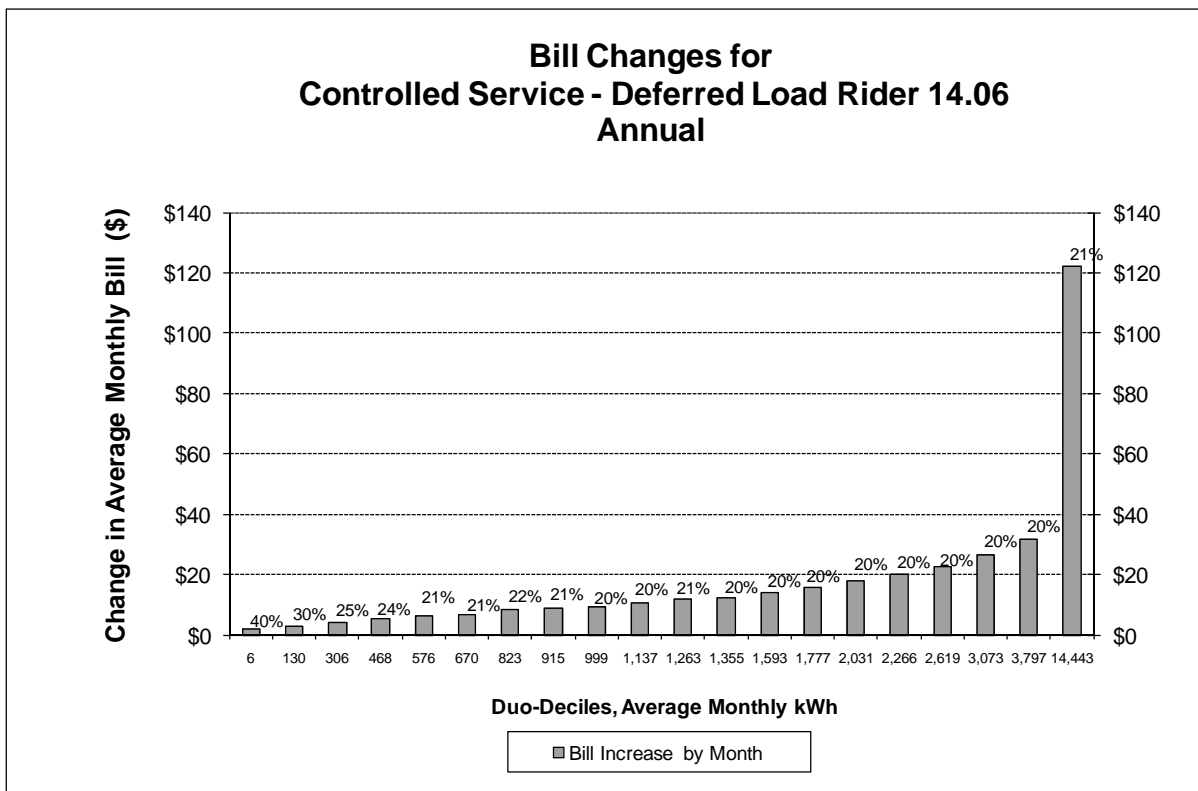
SD Deferred Load								Current Rev. \$214,119	Proposed Rev. \$256,501	Increase 19.79%
Controlled Service - Deferred Load 14.06										
	Customer Charge per month	Monthly Minimum Bill	Facilities Charge per month	Energy Charge per kWh						
				Summer	Winter					
Current Deferred Load Rate	\$2.50	Customer + Facilities	Flat charge per month \$3.00	All kWhs \$0.04450	\$0.04307					
				Penalty kWhs \$0.34108	\$0.11053					
Proposed Rate	\$3.00	Customer + Facilities	Flat charge per month \$4.00	All kWhs \$0.04992	\$0.05337					
				Penalty kWhs \$0.15340	\$0.16286					
Marginal Costs	\$6.50		<5000 kWh in all months \$11.23	\$0.04806	\$0.05139					
			>=5000 kWh in any month \$44.70	\$0.20332	\$0.21624					

22
23

1 Q. WHAT ARE THE BILL IMPACTS OF PROPOSED 14.06 DEFERRED LOAD
 2 RIDER?

3 A. As Figure 15 shows, 95 percent of the customers on this rider, those with up to an
 4 average of about 3800 kWh's of monthly consumption, will see bill increases of about
 5 \$32 or less – with the majority under \$20 per month. The remaining 5 percent of the
 6 customers with larger consumption will see average monthly bill increases of over
 7 \$120 per month, or approximately 21 percent.
 8

9 **Figure 15: Bill Impacts from 14.06 Proposed Deferred Load Rider**



10
 11

12 Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 14.07 FIXED
 13 TIME OF SERVICE RIDER

14 A. The proposed Fixed Time of Service (f/k/a Fixed Time of Delivery) rider, Table 23,
 15 introduces a small increase to the customer charge and minor adjustments to the
 16 facilities charges. The seasonal energy charges are set at 134 percent of marginal
 17 costs expected in the hours when customers will receive service under the rider. The

proposed energy charges, although purposely above marginal cost, provide an efficient and reasonable—but not optimal—price signal for this rate class.

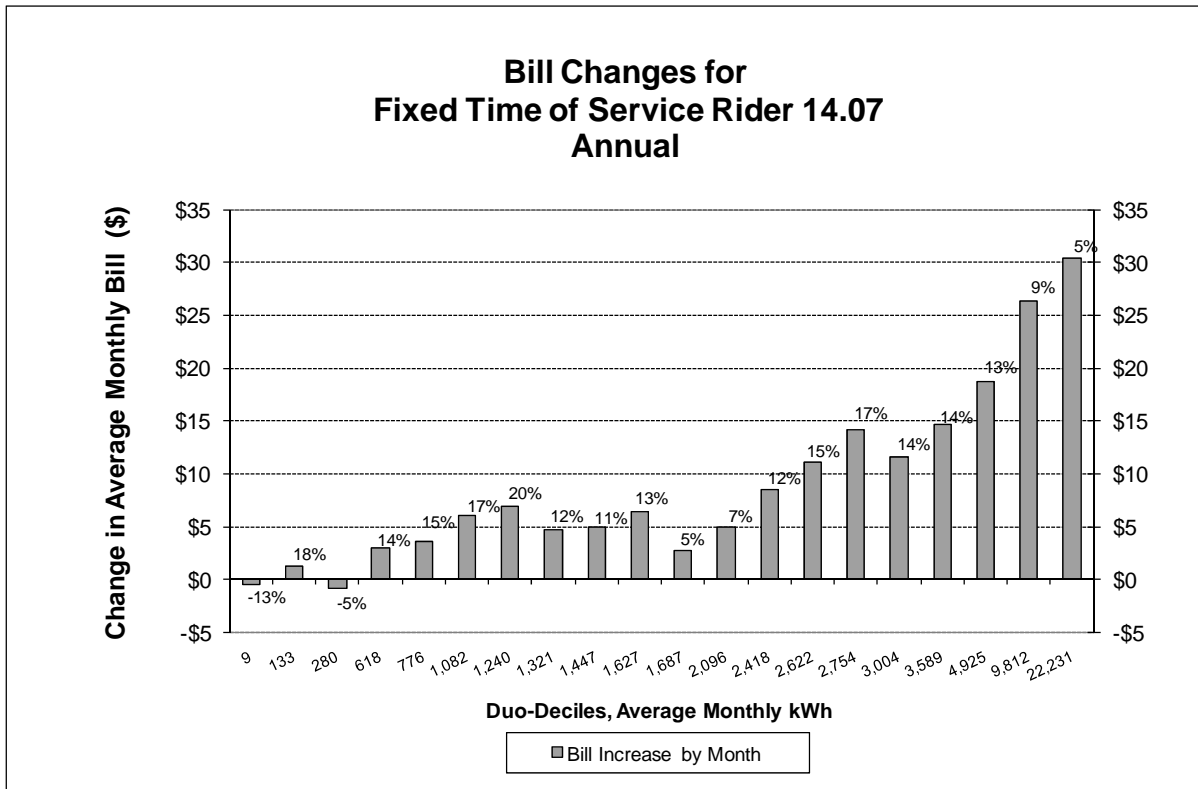
Table 23: Current and Recommended 14.07 Fixed Time of Service Rider and Marginal Costs

SD FTS 14.07		Current Rev	Proposed Rev.	Increase	
		\$72,788	\$79,180	8.78%	
Fixed Time of Service - Rate Codes 301,302,303					
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per Customer per month	Energy Charge per kWh	
Current Rate	Customer + Facilities Charge			Summer	Winter
Secondary < 100 kW (301)	\$1.00		\$3.00	\$0.02517	\$0.02689
Secondary > 100 kW (302)	\$1.50		\$15.00	\$0.02517	\$0.02689
Primary (303)	\$3.00		\$7.00	\$0.02506	\$0.02676
Proposed Rate	Customer + Facilities Charge			Summer	Winter
Secondary Self-Contained Metering (301)	\$1.50		\$3.00	\$0.01629	\$0.03331
			Penalty kWh	\$0.05673	\$0.03599
Secondary CT Metering (302)	\$2.00		\$16.00	\$0.01629	\$0.03331
			Penalty kWh	\$0.05673	\$0.03599
Primary (303)	\$5.00		\$8.00	\$0.01623	\$0.03318
			Penalty kWh	\$0.05667	\$0.03586
Marginal Costs			\$ per a month		
Secondary Self-Contained Metering (301)	\$4.80		\$9.70	\$0.01214	\$0.02481
			Penalty kWh	\$0.07302	\$0.06930
Secondary CT Metering (302)	\$5.12		\$72.26	\$0.01214	\$0.02481
			Penalty kWh	\$0.07302	\$0.06930
Primary (303)	\$20.01		\$26.31	\$0.01209	\$0.02472
			Penalty kWh	\$0.07290	\$0.06904

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 14.07 FIXED TIME OF SERVICE RIDER?

A. Figure 16 shows varied bill impacts for all customers on the proposed Fixed Time of Service Rider. Ninety (90) percent of customers will receive a decrease or less than a \$20.00/month increase. The remaining 10 percent will see an increase over \$25 per month.

1 **Figure 16: Bill Impacts from Proposed Fixed Time of Service (Self-Contained & CT**
 2 **Meter) Rider**
 3



4
 5
 6 Q. WHAT RATE SCHEDULES ARE YOU PROPOSING FOR SECTION 12 -
 7 PURCHASE POWER RIDERS?

8 A. OTP's proposal for the following rate schedules is only to propose new language in
 9 the Term and Conditions section, discussed in Section IV, Rate Schedule Changes
 10 Other Than Rates. Rates in this Rider are subject to approval in separate annual
 11 filings, as recently approved in EL09-026.

12
 13 Q. ARE THERE ANY OTHER RATE SCHEDULE PROPOSALS TO DISCUSS?

14 A. Yes. I will also address the rate design proposals for the following Mandatory and
 15 Voluntary Riders, Sections 13.0 and 14.0, respectively.

16
 17 Q. PLEASE DESCRIBE THE RATE LEVEL CHANGES IN SECTION 13.0 -
 18 MANDATORY RIDERS.

1 A. The only rate level change is the Energy Adjustment Rider (13.01). Revisions to this
2 rate schedule are discussed in Mr. Beithon’s testimony.

3

4 Q. PLEASE DESCRIBE THE RATE LEVEL CHANGES IN SECTION 14.0 –
5 VOLUNTARY RIDERS THAT HAVE YET TO BE ADDRESSED.

6 A. The rate level changes fall into two categories, those: 1) without rate changes; and 2)
7 with changes.

8 1. Those without rate changes in this proceeding are listed below:

9 ○ 14.02 Real-Time Pricing Rider: The current Rider was approved in OTP’s
10 most recent rate case in Case No. EL08-030.

11 ○ 14.08 Air Conditioning Control Rider: The current Rider was approved in
12 OTP’s most recent rate case in EL08-030.

13 ○ 14.09 Renewable Energy Rider (a/k/a TailWinds): The current Rider was
14 approved in OTP’s most recent rate case in EL08-030.

15 ○ 14.10 WAPA Bill Crediting Program Rider: The current Rider was
16 approved in EL08-030.

17 ○ 14.11 Released Energy Rider (Section 14.11): The current Rider was
18 approved in OTP’s most recent rate case in EL08-030.

19 2. Those with rate changes in this proceeding are listed below:

20 ○ 14.03 Large General Service Rider: The proposal adds an administrative
21 charge of \$199 per month for all customers on this Rider. The proposed
22 charge is the same as levied in the Real Time Pricing Rider and the LGS
23 Rider – System Marginal Energy Pricing.

24

25 **V. RATE SCHEDULE CHANGES OTHER THAN RATES.**

26

27 Q. IS OTP PROPOSING RATE SCHEDULE CHANGES OTHER THAN THOSE
28 RELATING TO RATES?

29 A. Yes. In its last rate case, OTP made several improvements and updates to its rate
30 book. In this case, OTP is expanding on those improvements and is making additional
31 changes mainly to provide clarity of service conditions and requirements for

1 customers and OTP. Many of the changes are common to all rate schedules and others
2 are specific to individual rate schedules. A number of the changes are reflected in a
3 Matrix of Tariff Changes, which is Exhibit __ (DGP-1), Schedule 3, of my testimony.
4 The following is a discussion of the substantive proposed changes. Exhibit __ (DGP-
5 1), Schedule 3, provides a description of the non-substantive proposed changes.
6

7 **A. RATE SCHEDULE – RATE CODES TO BE COMBINED**
8

9 Q. IS OTP PROPOSING TO COMBINE ANY RATE CODES?

10 A. Yes. OTP is proposing to combine two rate codes in OTP’s Section 11.03 - Outdoor
11 Lighting – Energy Only Dusk to Dawn rate schedule. We are proposing to combine
12 rate code 70-744 with rate code 70-749. Rate code 70-744 provides non-metered
13 energy only service to sign lighting and rate code 70-749 provides non-metered energy
14 only service to outdoor lighting.
15

16 Q. WHY IS OTP PROPOSING TO COMBINE THESE TWO RATE CODES?

17 A. Non-metered sign lighting is billed the same way as other non-metered outdoor
18 lighting. Currently OTP tracks sign lighting with a light kind code of SIGN in our
19 Customer Information System (“CIS”). Tracking sign lighting with the rate code of
20 70-744 and a light kind code of SIGN is duplicative. Combining rate code 70-744
21 with 70-749 will not eliminate OTP’s ability to determine the amount of kWh’s and
22 revenue associated with sign lighting because this information will be available by
23 using the light kind code of SIGN. Therefore, elimination of this rate code is
24 reasonable.
25

26 **B. RATE SCHEDULES – OTHER RATE CODE CHANGES**
27

28 Q. HAS OTP PROPOSED ANY OTHER CHANGES TO ITS RATE CODES?

29 A. Yes. We are also proposing to change the rate level from 70 to 71 in order to
30 accommodate the transition from current rates to final rates within our CIS. This

1 change is reflected in the Description box on the rate schedules and is best shown on
2 the redline versions of the rate schedules found in Volume 3.

3
4 **C. GENERAL RULES AND REGULATIONS**

5
6 Q. IS OTP PROPOSING CHANGES TO ITS GENERAL RULES AND
7 REGULATIONS?

8 A. Yes. As I previously stated, OTP made several improvements and updates to its rate
9 book in its last rate case. In this case OTP is expanding on those improvements and is
10 making additional changes, which I will describe in further detail below.

11
12 **1. General Changes to the General Rules and Regulations**

13
14 Q. PLEASE DESCRIBE THE GENERAL CHANGES TO THE GENERAL RULES
15 AND REGULATIONS.

16 A. In preparation for filing this rate case, OTP assembled an internal cross functional
17 group that reviewed OTP's General Rules and Regulations and provided
18 recommended changes. These changes consisted of grammar, spelling, organization
19 and compliance with South Dakota statutes and rules, which I will describe in more
20 detail in the next several sections of my testimony. In addition to the changes
21 described below, OTP made a few changes for consistency throughout Sections 1.01
22 through 8.01 of OTP's General Rules and Regulations ("Consistency Changes").
23 First, in many instances we capitalized the first letter of words that are defined in
24 Section 8.01 – Glossary. Second, in several locations the word "premises" was
25 changed with the phrase "service location."

26
27 **2. Article 1: General Service Rules**

28
29 Q. PLEASE DESCRIBE THE GENERAL CHANGES TO ARTICLE 1 OF THE
30 GENERAL RULES AND REGULATIONS.

1 A. Section 1.01 Scope of General Rules and regulations, OTP did not make substantial
2 changes to this section.

3 Section 1.02, Application for Service, there are two items I would like to address.

4 First, we added clarifying language regarding the requirement of an applicant for
5 service to be 18 years of age or older. A customer can be under the age of 18 if the
6 customer provides evidence that the person is an emancipated minor.

7 The second change relates to the requirement for a customer to take service for a
8 minimum of one year. OTP added language that allows a customer to change rates
9 within the one year period if it is determined that a customer no longer qualifies for
10 service under the selected rate.

11 Section 1.03, Deposits, Guarantees, OTP did not make substantive changes to this
12 section.

13 Section 1.04, Customer Connection Charge, the changes to this section are more
14 organizational in nature for better understanding of when connection charges apply.
15 There are three changes that relate to the organization of this section.

16 First, removed the second sentence in the Connection Charge After Disconnect for
17 Nonpayment paragraph. This sentence was removed because the time period for
18 reconnecting service has been addressed in the Additional Charges paragraph.

19 Second, the Temporary Meter Socket Detachment and Reattachment Charge
20 paragraph has been revised to clarify the types of equipment OTP representatives will
21 work on and OTP's ability to decline this type of service.

22 Third, in the additional charges paragraph, OTP added a description of the timing
23 of reconnecting service outside normal business hours and how overtime charges are
24 calculated.

25 Section 1.05, Contracts and Agreements, we made minor changes to the language
26 to these contracts and agreements.

27 There are two changes that have been made to all three service agreements, which
28 include the electric service agreement, the irrigation electric service agreement and the
29 outdoor lighting and municipal services agreement. First, additional language was
30 added to explain that service to the customer will be subject to mandatory riders and
31 any voluntary riders selected by the customer. This language was added to paragraph

1 4 in the electric service and irrigation service agreements and in paragraph 7, 10 and
2 13 of the outdoor lighting and municipal services agreement. Second, additional
3 language was added to explain that termination of the agreement by the customer does
4 not relieve the customer from their obligation to make payment to the Company as
5 outlined in the agreement. This change has been made to paragraph 6 of the electric
6 service and irrigation service agreements and paragraph 2 of the outdoor lighting and
7 municipal services agreement.

8 For the Summary Billing Service Contract, OTP removed the reference to
9 Attachment 1 because this specific attachment is no longer necessary.

10 For the Controlled Service Agreement OTP added a further description to
11 paragraph 1, where the customer acknowledges the type of back-up system and
12 accepts the risk of damage by not having an automatic back-up system.

13 Copies of OTP's sample forms are also included in Section 1.05.

14 Section 1.06 was added for future use.

15 Section 1.07, was added for future use.

16 Section 1.08, was added for future use.

17
18 **3. Article 2 – Service Classification**

19
20 Q. PLEASE DESCRIBE THE GENERAL CHANGES TO ARTICLE 2 OF THE
21 GENERAL RULES AND REGULATIONS.

22 A. Section 2.01, Assisting Customers in Rate Selection, OTP is not proposing any
23 changes to this section.

24 Section 2.02, Service Classification, for clarity of the provisions for farm
25 customers, OTP revised the last paragraph that describes the customers options for
26 metering farm and residential use when customers have both types of service to a
27 dingle farm.

1 **4. Article 3 - Curtailment or Interruption of Service**

2
3 Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 3 OF THE RULES AND
4 REGULATIONS.

5 A. Section 3.00 contains provisions for curtailment or interruption of service. OTP made
6 very few changes to this section.

7 Section 3.01, Disconnection of Service, no changes.

8 Section 3.02, Curtailment or Interruption of Service, OTP did not make any
9 substantive changes to this section. The minor changes to this section provide better
10 clarity or readability.

11 Section 3.03, 3.04, Reserved for Future Use, no changes.

12 Section 3.05, Continuity of Service, minor wording changes were made for clarity
13 and readability.

14
15 **5. Article 4 - Metering and Billing**

16
17 Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 4 OF THE RULES AND
18 REGULATIONS.

19 A. This section contains the generally applicable provisions on service metering, billing,
20 and payment matters. Most of the changes proposed in this section are for clarity and
21 easier readability of the provisions.

22 Section 4.01, Meter and Service Installations, OTP made changes to the first two
23 paragraphs that relate to the requirements for meter sockets. OTP revised the
24 description of who is responsible for the wiring inside the meter socket and current
25 transformer cabinet. Also, OTP proposes a new paragraph that describes when a
26 wiring affidavit will be required for service connections. The other changes made to
27 this section were for better clarity or readability and also include some of the
28 Consistency Changes.

29 Section 4.02, Meter Readings, explains OTP's obligations and rights with respect
30 to meter reading. OTP revised the language to clarify when meters are read and when
31 a bill maybe estimated.

1 Section 4.03, Estimated Billing, describes OTP's and customers' respective rights
2 and obligations concerning estimated billings. OTP did not make any substantive
3 changes to this section.

4 Section 4.04, Meter Testing, identifies rights and obligations (including for billing
5 adjustments) where a customer's meter registers more than 2 percent fast or slow.
6 OTP did not make any substantive changes to this section.

7 Section 4.05, Access to Customer Premises, identifies rights and obligations of the
8 Company. OTP did not make any substantive changes to this section.

9 Section 4.06, Establishing Demands, two minor changes are being proposed in this
10 section. Neither of these changes affect the provisions or intent of the section.

11 Section 4.07, Monthly Billing Period and Prorated Bills, OTP revised this section
12 to allow for clearer description the billing components that are prorated when the bill
13 is rendered for a period outside a normal billing period.

14 Section 4.08, Electric Service Bill - Identification of Amounts and Meter Reading,
15 the proposed changes to this section are more organizational in nature for easier
16 readability and more clarity. The last paragraph was moved to the beginning of the
17 first paragraph and revised. The second paragraph was one long sentence. So the
18 paragraph was reorganized and broken up into several sentences. The provision and
19 intent of this section remains unchanged.

20 Section 4.09, Billing Adjustments, identifies the rights and obligations for billing
21 adjustments. OTP did not make any substantive changes to this section.

22 Section 4.10, Payment Policy, identifies when customer payments are due and
23 when late payments apply. Other than a few of the Consistency Changes, OTP is not
24 proposing substantive changes to this section.

25 Section 4.11, Even Monthly Payment (EMP) Plan, describes OTP's optional
26 program permitting customers to choose to budget their electric service expenses over
27 a twelve month period. The changes being proposed in this section are to provide a
28 better description of OTP's Even Monthly Payment Plan and do not change the
29 content or the intent of this provision.

30 Section 4.12, Summary Billing Service, describes a customer's ability to
31 consolidate multiple billed accounts into a master bill with a single billing date. The

1 changes being proposed in this section consist of some of the Consistency Changes,
2 adding a phrase in the fourth paragraph that helps describe which billing components
3 will be accumulated for a customer's total summary bill.

4 Section 4.13, Account History Charge, addresses the expense incurred by OTP
5 where a single customer frequently requests multiple account history reports. In
6 addition to the Consistency Changes, OTP is proposing to eliminate the 6 month time
7 period for monitoring when a customer exceeds 10 account history requests. We are
8 proposing this charge be imposed when a customer asks for 10 or more account
9 history requests at one time. The intent of this change is to allow a maximum of ten
10 history reports before the customer is charged and also a cap on the charge is added.
11 This recognizes there is a cost associated with providing account histories and also
12 there are efficiencies when several requests are provided at one time. The tracking of
13 requests over a 6 month period of time has been problematic and not efficient, which
14 is the main reason OTP is proposing to eliminate the time requirement for the account
15 history charge.

16 Section 4.14, Combined Metering, this provision allows customers with
17 contiguous property and with minimum entrance ratings of 750 kVA to combine
18 multiple service and metering points into one meter reading. Other than some of the
19 Consistency Changes, no other changes are being proposed in this section.
20

21 **6. Article 5 - Standard Installation and Extension Rules**

22
23 Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 5 OF THE NEW RULES
24 AND REGULATIONS.

25 A. Section 5.01, Service Connection, contains the terms and conditions that define the
26 respective rights and obligations of OTP and customers concerning the installation,
27 maintenance, and ownership of lines and equipment supplied by OTP to provide
28 electric service to the customer. This section was previously in Section 5.05 and the
29 entire contents of this section have been moved from Section 5.05 to 5.01. Very few
30 minor changes have been made to this section and include some of the Consistency
31 Changes.

1 Section 5.02, Voltage Classification, explains how and when OTP will provide
2 service at Secondary and Primary Voltage, and at Transmission Voltage, capacities.
3 This section was previously in Section 5.04 and the entire contents of this section have
4 been moved from Section 5.04 to 5.02.

5 In order to provide a clear description of the secondary and primary voltages
6 provided by the Company, OTP revised the first paragraph under Service at Secondary
7 Voltage. This paragraph was separated into two paragraphs. One paragraph describes
8 service at secondary voltage and the other paragraph describes service at primary
9 voltage. OTP revised and clarified the descriptions of the voltages available to
10 customers and who owns the facilities. The paragraph for service installation was
11 revised, clarified and moved to the end of Section 5.02. These proposed changes
12 clarify the service voltages available to customers and the ownership of the facilities
13 that provide electric service.

14 Section 5.03, Facilities, Definitions, Installations and Payments, provides
15 definitions of facilities provided by the Company, and explains the installation and
16 payment for facilities that are required by the Company. This section was previously
17 in Section 5.02 and the entire contents of this section have been moved from Section
18 5.02 to 5.03. The recommended changes to this section include some of the
19 Consistency Changes, clarifying the definitions and reorganization of the paragraphs.
20 The changes do not alter the intent of this provision. The changes provide clarity of
21 the facilities provided by the customer and when payment for the facilities may be
22 required.

23 Section 5.04, Extension Rules and Minimum Revenue Guarantee, OTP is
24 recommending clarifying language and slight reorganization of this section to better
25 explain situations when a minimum revenue guarantee may apply. This section was
26 previously in Section 5.01 and the entire contents of this section have been moved
27 from Section 5.01 to 5.04. These changes do not change the application of when a
28 minimum revenue guarantee may apply.

29 Section 5.05, Temporary Services, explains the requirements for a customer taking
30 temporary service. This section was previously in Section 5.03 and the entire contents

1 of this section have been moved from Section 5.03 to 5.05. Other than moving this
2 section, OTP did not make any changes to this section.

3
4 **7. Article 6 - Use of Service Rules**

5
6 Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 6 OF RULES AND
7 REGULATIONS.

8 A. Section 6.01, Customer Equipment, contains some of the Consistent Changes. No
9 substantive changes are recommended for this section.

10 Section 6.02, Use of Service, OTP is not proposing any substantive changes to this
11 section.

12 **8. Article 7 - Company's Rights**

13
14 Q. PLEASE DESCRIBE THE CONTENTS OF ARTICLE 7 OF RULES AND
15 REGULATIONS.

16 A. Section 7.01, Waiver of Rights or Default, other than changing the word "is" to "shall"
17 in front of the phrase "a waiver," no other changes are being proposed in this section.

18 Section 7.02, Modifications of Rates, Rules and Regulations, states that OTP has
19 the right to modify its rates, rules and regulations in the future, in any manner
20 permitted by law. Other than adding the word "The" in front of the word "Company"
21 and replacing the phrase "are provided with" with the phrase "shall receive such," no
22 other changes are being proposed in this section.

23
24 **9. Article 8 - Glossary and Definition of Symbols**

25
26 Q. PLEASE DESCRIBE THE CONTENTS OF SECTION 8.01 GLOSSARY.

27 A. Section 8.01 defines commonly used terms in the above-discussed provisions of the
28 General Rules and Regulation using the commonly accepted meaning of those terms
29 in the industry. OTP is proposing to add definitions for the following terms: Account,
30 Customer, Governmental Unit, Megawatt, Seasonal Customer, Single-phase, Tariff
31 (Tariff Schedules), and Three-phase. The term Municipality has been replaced by the

1 term Governmental Unit. These terms are used in OTP's General Rules and
2 Regulations and rate schedules.

3
4 Q. PLEASE DESCRIBE THE CONTENTS OF SECTION 8.02 DEFINITION OF
5 SYMBOLS.

6 A. Section 8.02 provides the key showing the meaning of the symbols that will be used in
7 the rate schedule as revisions are made in the future. No substantive changes are
8 being proposed in this section.

9
10 **D. OTHER RATE SCHEDULE REVISIONS**

11
12 Q. IS OTP PROPOSING OTHER REVISIONS TO ITS RATE SCHEDULES?

13 A. Yes. OTP's proposed changes to rate schedules are described in the remaining portion
14 of my testimony.

15
16 **1. General Changes to Rate Schedules**

17
18 Q. ARE THERE ANY GENERAL CHANGES BEING PROPOSED THAT MAY BE
19 CONSISTENT ON MOST IF NOT ALL RATE SCHEDULES?

20 A. Yes. The following changes have been made in order to have language that is as
21 consistent as possible in sections that are on most if not all rate schedules. For the
22 remainder of my testimony, these changes shall be referred to as "Consistent Rate
23 Schedule Changes." First, in the Description boxes, changed from rate level "70" to
24 rate level "71", in the RULES AND REGULATIONS section, replaced the word
25 "tariff" with "electric rate schedule," and replaced the word "schedule" with "service"
26 or in some cases the word "rider." In the Mandatory and Voluntary Riders section,
27 OTP changed the text so the language of this section is consistent among all other rate
28 schedules and riders. Finally, OTP capitalized the first letter of words defined in
29 Section 8.01 – Glossary, which includes the added defined terms discussed earlier in
30 my testimony.

1 Q. ARE THERE RATE SCHEDULES WHERE OTP MADE THE CONSISTENT
2 RATE SCHEDULE CHANGES AND DID NOT MAKE ANY SUBSTANTIVE
3 CHANGES?

4 A. Yes. The following list represents the list of rate schedules where OTP only made the
5 Consistent Rate Schedule Changes.

- 6 1. Residential Demand Control (Commonly Identified as RDC) – Section 9.02
- 7 2. Outdoor Lighting Dusk to Dawn – Section 11.04
- 8 3. Small Power Producer Rider(s) – Sections 12.01, 12.02 and 12.03
- 9 4. Fuel Adjustment Clause Rider – Section 13.01
- 10 5. Energy Efficiency Partnership (EEP) Cost Recovery Rider – Section 13.04
- 11 6. Real Time Pricing Rider – Section 14.02
- 12 7. Controlled Service – Interruptible Load – CT Metering Rider (Large Dual Fuel)
13 – Section 14.04.
- 14 8. Air Conditioning Control Rider (Commonly identified as **CoolSavings** – Section
15 14.08
- 16 9. Voluntary Renewable Energy Rider – Section 14.09
- 17 10. Bulk Interruptible Service – Section 14.12
- 18 11. Communities Served – Section 15.00
- 19 12. Summary of Contracts with Deviations – Section 16.00

20
21 **2. Changes to Residential Service – Section 9.01**
22 **Rate Codes 70-101**
23

24 Q. PLEASE DESCRIBE THE CHANGES BEING PROPOSED TO THE
25 RESIDENTIAL SERVICE, SECTION 9.

26 A. In addition to the Consistent Rate Schedule Changes, one notable change is the
27 recommended change to seasonal residential services. We are proposing to remove
28 the language that describes when OTP will typically read seasonal service meters and
29 when a bill is rendered. OTP serves many cabins and seasonal residences, which
30 means the electricity use typically occurs from late spring through early fall. Several
31 of these locations are very difficult to gain access to during the winter months due to
32 snow conditions. This is one reason seasonal service works well for OTP because

1 typically customers in these locations are not using the service during the winter time
2 with the exception of occasional weekend use. Seasonal residential service is
3 currently not limited to a given period of time other than a minimum of four months.
4 So the provision of when OTP would typically read meters and render a bill is not
5 consistent with some customers' usage and, in order to minimize confusion, we are
6 proposing to remove this provision.

7
8 Q. ARE THERE ANY OTHER CHANGES BEING PROPOSED TO SEASONAL
9 RESIDENTIAL SERVICE?

10 A. Yes. There are three other changes. First, we have removed the reference to lake
11 cottages because some residences around lakes are not cottages, but rather homes
12 where the electric use is seasonal. Second, we have added a requirement that seasonal
13 residential service is available to customers who do not also receive service on a
14 voluntary rate rider. Currently most of the voluntary rate riders selected by residential
15 customers are water heating and controllable electric heating rates. These customers
16 are billed monthly, so they would not qualify for seasonal service. Third, we have
17 also added a provision where, if the first bill rendered for the season exceeds an
18 average of 200 kilowatt-hours per month for the off-season, the customer may no
19 longer be eligible for seasonal service. This will help OTP identify those customers
20 who may be a year-round customer rather than a seasonal customer and put these
21 customers on year-round monthly billing.

22
23 **3. Farm Service – Section 9.03**
24 **Rate Code 70-361**
25

26 Q. WHAT CHANGES ARE PROPOSED FOR FARM SERVICE?

27 A. In addition to the Consistent Rate Schedule Changes, we are also proposing to
28 eliminate the facilities charge based on the size of the transformer providing service to
29 the customer due to customer confusion and potential for misapplication of the charge.
30 The facilities charge will apply to all three phase customers regardless of the size of
31 the transformers serving the customer. The proposed change to how OTP charges for
32 facilities will be easier for customers to understand and will help with correct

1 application of the rate by OTP employees and in OTP's Customer Information
2 System.

3
4 **4. Small General Service Under 20 Kw – Section 10.01**
5 **Rate Codes 70-404, 70-405.**
6

7 Q. WHAT CHANGES ARE PROPOSED WITH RESPECT TO SMALL GENERAL
8 SERVICE UNDER 20 KW?

9 A. We are proposing some of the Consistent Rate Schedule Changes and there are three
10 changes that I would like to address.

11
12 Q. PLEASE DESCRIBE THE THREE CHANGES TO SMALL GENERAL SERVICE
13 UNDER 20 KW?

14 A. First, in the Application section, we are proposing to clarify the description of the
15 types of customers and service applicable under this rate schedule. The second change
16 is the addition of Seasonal Small General Service. OTP serves many customers in
17 rural areas and around lakes. As such, there are situations where seasonal general
18 service would be a good option both for the customers and OTP. Some examples
19 where such service may be appropriate are resorts, campgrounds, ball fields, and parks
20 within cities. These situations typically require electric service that is seasonal in
21 nature and would be a good fit for this new provision. The seasonal provisions added
22 are similar to the seasonal service available for residential customers. For example, if
23 the first bill rendered for the season exceeds an average of 400 kilowatt-hours per
24 month for the off-season, the customer may no longer be eligible for seasonal service.
25 The last change relates to the terms and conditions section of the rate schedule. We
26 have removed the provision that gives the customer an option of returning to Small
27 General Service under 20 kW if the customer has a billing demand of less than 20 kW
28 for 12 consecutive months. We have added that any customer who's is over 20 kW
29 three times in the most recent 12 months will be moved to General Service 20 kW or
30 greater.

31

1 Q. WHY ARE YOU PROPOSING TO REMOVE THE PROVISION THAT GIVES
2 THE CUSTOMER AN OPTION OF RETURNING TO SMALL GENERAL
3 SERVICE IF THE CUSTOMER HAS A BILLING DEMAND OF LESS THAN 20
4 KW FOR 12 CONSECUTIVE MONTHS?

5 A. The provision was originally used as a transition mechanism for the Small General
6 Service rate, which was a new rate, proposed and accepted in our last rate case. The
7 transition provision is no longer necessary in this rate schedule. Therefore we have
8 eliminated this provision from the Small General Service Under 20 kW rate.

9

10 **5. General Service 20 Kw and Greater – Section 10.02**
11 **Rate Codes 70-401, 70-403**
12

13 Q. WHAT CHANGES IS OTP REQUESTING WITH RESPECT TO GENERAL
14 SERVICE 20 KW AND GREATER?

15 A. We are proposing the Consistent Rate Schedule Changes and there are two other
16 changes that I would like to address.

17

18 Q. PLEASE DESCRIBE THE FIRST CHANGE TO GENERAL SERVICE 20 KW
19 AND GREATER RATE.

20 A. In the Application section, OTP's proposed changes are very similar to the changes
21 discussed in the General Service Under 20 kW rate. These changes provide
22 clarification of the types of customers and service applicable under this rate schedule.

23

24 Q. WHAT IS THE SECOND CHANGE TO GENERAL SERVICE 20 KW AND
25 GREATER BEING PROPOSED BY OTP?

26 A. We are proposing to add sections that describe metered demands, adjustments for
27 excess reactive demand and modify the language in the determination of billing
28 demand and determination of facilities charge.

29

30 Q. WHY IS OTP PROPOSING TO ADD THE METERED DEMANDS AND
31 ADJUSTMENT FOR EXCESS REACTIVE DEMAND SECTIONS?

1 A. These sections are being added so customers and OTP employees can refer to specific
2 sections on the rate schedule for a description of how OTP measures demands and
3 makes adjustments to the demands for billing purposes.

4
5 Q. WHY IS OTP PROPOSING TO CHANGE THE DETERMINATION OF BILLING
6 DEMAND AND DETERMINATION OF FACILITIES CHARGE?

7 A. Similar to the metered demand section, the changes being proposed in these two
8 sections will allow customers and OTP employees the ability to refer to specific
9 sections on the rate schedule for a description of how the billing demand and the
10 facilities charge are determined for customers on the General Service 20 kW and
11 Greater rate.

12
13 **6. General Service – Time of Use – Section 10.03**
14 **Rate Codes 70-708, 70-709, 70-710**
15

16 Q. WHAT CHANGES IS OTP REQUESTING WITH RESPECT TO THE GENERAL
17 SERVICE– TIME OF USE RATE?

18 A. In addition to some of the Consistent Rate Schedule Changes, OTP is proposing the
19 following changes: Changing the Section number from 10.04 to 10.03, replacing the
20 word “Commercial” with the word “General” in the title, changing how customers are
21 billed for facilities, and clarifying the Definition of Declared, Intermediate and Off-
22 Peak Periods by Season section.

23
24 Q. WHY IS OTP CHANGING THE SECTION NUMBER FROM 10.04 TO 10.03?

25 A. For the most part, OTP’s rate schedules are organized by OTP’s classes of service.
26 General Service – Time of Use, Section 10.04 is in the same class as General Service
27 Under 20 kW, Section 10.01 and General Service 20 kW and Greater, Section 10.02,
28 so the order of OTP’s rate schedules is currently out of line. This change is
29 administrative in nature, and will help OTP employees understand which Sections fall
30 into OTP’s various classes of service.

31

1 Q. WHY IS OTP REPLACING THE WORD “COMMERCIAL” WITH THE WORD
2 “GENERAL” IN THE TITLE?

3 A. This change is being proposed because the other rate schedules in the small general
4 service class contain the word “General” in the title instead of “Commercial.”
5

6 Q. WHAT CHANGES IS OTP PROPOSING REGARDING THE SECTIONS ON
7 DEMANDS IN THIS RATE SCHEDULE AND WHY?

8 A. OTP recommends adding sections on metered demands, adjustments for excess
9 reactive demand and modifying the sections on determination of billing demand and
10 determination of facilities charge. These changes have been made to provide a clear
11 description of how OTP measures demands, makes adjustments to demands for billing
12 purposes and bills customers for facilities and kW use.
13

14 Q. WHAT CHANGES ARE BEING PROPOSED BY OTP IN ORDER TO CLARIFY
15 THE DEFINITION OF DECLARED, INTERMEDIATE AND OFF PEAK
16 PERIODS?

17 A. For consistency with the Off-peak definition, OTP is proposing to add the phrase “For
18 all kW and kWh used during the” in the definitions for the declared and intermediate
19 periods section. OTP bills customers for kWh and kW use, and for clarity it is
20 appropriate to add this phrase to the definition of these two periods.

21 For the Off-peak period, we are proposing to replace the phrase “Weekdays or
22 Saturdays” with the phrase “Monday through Saturday.” Specifying the days in this
23 description is clearer than using the generic term of weekdays.
24

25 **7. Large General Service – Section 10.04**
26 **Rate Codes 70-602, 70-603, 70-632**
27

28 Q. WHAT CHANGES ARE BEING PROPOSED WITH RESPECT TO LARGE
29 GENERAL SERVICE?

30 A. Along with some of the Consistent Rate Schedule Changes, OTP is recommending the
31 following changes: minor changes to the availability section, additions and changes to

1 the paragraphs that describe metered demands, adjustments for excess reactive
2 demand, determination of billing demand and determination of facilities charge.

3
4 Q. WHAT CHANGES IS OTP PROPOSING TO THE APPLICATION OF SCHEDULE
5 SECTION OF THIS RATE SCHEDULE AND WHY?

6 A. The changes being proposed in this section are very similar to the changes to the same
7 section in the General Service Under 20 kW and General Service 20 kW and Greater
8 rates. These changes consist of language changes to better describe the applicable
9 types of customers and service under this rate schedule.

10
11 Q. WHAT CHANGES IS OTP PROPOSING REGARDING THE SECTIONS ON
12 DEMANDS IN THIS RATE SCHEDULE AND WHY?

13 A. OTP recommends adding sections on metered demands and modifying the sections on
14 adjustments for excess reactive demand, determination of billing demand and
15 determination of facilities charge. These changes are being made for reasons similar
16 to those described for General Service 20 kW and Greater and General Service – Time
17 of Use.

18
19 **8. Large General Service – Time of Day Section 10.05**
20 **Rate Codes 70-611, 70-613, 70-615, 70-610, 70-614, 70-612, 70-639,**
21 **70-637, 70-640**

22
23 Q. WHAT CHANGES IS OTP PROPOSING WITH RESPECT TO LARGE GENERAL
24 SERVICE – TIME OF DAY?

25 A. Other than making some of the Consistent Rate Schedule Changes, OTP is proposing
26 changes to the paragraphs regarding demands, which were made for similar reasons as
27 described for General Service 20 kW and Greater, General Service – Time of Use and
28 Large General Service rates.

29
30

1 **9. Standby Service – Section 11.01**
2 **Rate Codes 70-941 through 70-958**
3

4 Q. WHAT CHANGES ARE BEING PROPOSED WITH RESPECT TO STANDBY
5 SERVICE?

6 A. Other than proposing some of the Consistent Rate Schedule Changes, OTP is
7 proposing to move and revise the last sentence in the definition of backup demand to a
8 new definition of backup demand charge. This revised definition is a clearer
9 description of how the backup demand charges will be billed. OTP also removed all
10 references to the Special Billing Demand, which no longer exists in any of OTP’s rate
11 schedules or riders.

12 **10. Irrigation Service – Section 11.02**
13 **Rate Codes 70-703 through 70-706**
14
15

16 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
17 IRRIGATION SERVICE?

18 A. OTP is recommending the following changes to irrigation service: replacing the word
19 “facilities” with “fixed,” clarifications to the definition of seasons, added Character
20 and Conditions of Service section and some of the Consistent Rate Schedule Changes.
21

22 Q. PLEASE DESCRIBE WHY OTP IS PROPOSING TO CHANGE THE WORD
23 “FACILITIES” WITH “FIXED” WITH RESPECT TO IRRIGATION SERVICE?

24 A. The places where the word “facilities” is being changed to “fixed” are in the rate
25 boxes and in the facilities charge section of this schedule. This change is being
26 proposed because the phrase “fixed charge” is used in the Irrigation Service agreement
27 and the paragraph describing the charge in the rate schedule. The term “fixed charge”
28 is also consistent with how this charge is typically referred to by OTP employees and
29 how the charge appears on customer bills.
30

31 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING IN THE DEFINITION
32 OF SEASONS WITH RESPECT TO IRRIGATION SERVICE?

1 A. For consistency with the Off-peak definition, OTP is proposing to add the phrase “For
2 all kW and kWh used during the” in the definitions for the declared and intermediate
3 periods section. OTP bills customers for kWh and kW use, and for clarity it is
4 appropriate to add this phrase to the definition of these two periods.

5 For the Off-peak period, we are proposing to replace the phrase “Weekdays or
6 Saturdays” with the phrase “Monday through Saturday.” Specifying the days in this
7 description is clearer than using the generic term of weekdays.

8
9 **11. Outdoor Lighting - Energy Only Dusk to Dawn – Section 11.03**
10 **Rate Codes 70-744, 70-748 and 70-749**
11

12 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
13 OUTDOOR LIGHTING DUSK TO DAWN SERVICE?

14 A. In addition to the Consistent Rate Schedule Changes, as described earlier in my
15 testimony, OTP is recommending eliminating rate code 70-744, which is for Sign
16 Lighting. In the Equipment and Service Ownership paragraph, OTP clarified the
17 language regarding the customers disconnect switch, which must be UL approved or
18 meet National Electric Code standards.

19
20 **12. Municipal Pumping Service – Section 11.05**
21 **Rate Codes 70-873 and 70-874**
22

23 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
24 MUNICIPAL PUMPING SERVICE?

25 A. OTP is recommending the following changes: some of the Consistent Rate Schedule
26 Changes, and eliminated statements regarding combined metering. In addition,
27 paragraphs were added that describe, metered demands, adjustments for excess
28 reactive demand, determination of billing demand and determination of facilities
29 charge.

30
31 Q. WHY IS OTP PROPOSING TO ELIMINATE LANGUAGE REGARDING
32 COMBINED METERING?

1 A. In the application of schedule paragraph, the current language regarding combined
2 metering applies to electric space heating loads. Currently, electric space heating
3 loads are served under one of OTP's controlled service rates and, as such, OTP does
4 not have any situations of combined metering for municipal pumping service
5 customers. Therefore, the language regarding combined metering no longer applies
6 and customers with electric space heating loads are better served by being on one of
7 OTP controlled service rates.

8

9 Q. WHY IS OTP PROPOSING TO ADD PARAGRAPHS FOR METERED
10 DEMANDS, ADJUSTMENTS FOR EXCESS REACTIVE DEMAND,
11 DETERMINATION OF BILLING DEMAND AND DETERMINATION OF
12 FACILITIES CHARGE?

13 A. These paragraphs are being added as a result of our proposal to change the facilities
14 charge to be based on demand (kW) rather than a flat facilities charge. These
15 paragraphs have been added to provide a clear description of how OTP measures
16 demand, makes adjustments to demands for billing purposes and bills municipal
17 pumping service customers for kW use.

18

19 **13. Civil Defense – Fire Sirens – Section 11.06**
20 **Rate Codes 70-842**
21

22 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
23 MUNICIPAL PUMPING SERVICE?

24 A. OTP is recommending the following changes: some of the Consistent Rate Schedule
25 Changes, reduction in the length of feet for a span of wire and the requirement of
26 additional cost associated with additional transformer capacity. These changes make
27 it very clear what equipment will be provided by OTP when providing civil defense –
28 fire siren service to customers under this rate schedule.

29

**14. Purchase Power Riders – Section 12.01 – 12.03
Rate Codes – 70-9020, 9021,9030-9033, and 9040-9043**

1
2
3
4 Q. WHAT LANGUAGE ARE YOU ADDING TO THE TERMS AND CONDITIONS
5 SECTION OF SMALL POWER PRODUCER SCHEDULES, SECTION 12.01 –
6 12.03?

7 A. In the Terms and Conditions section OTP moved what was previously number 11 up
8 to become what is now number 1. OTP added language to number 1 that requires the
9 Customer to complete the Interconnection Agreement for Small Generator Facility
10 Tier 1, Tier2, Tier 3 or Tier 4 Interconnection. OTP also referred the customer to the
11 procedures set forth in ARSD chapter 20:10:36. The last item OTP added to number 1
12 is to require the customer to follow the Company’s Guidelines for Generation, Tie-
13 Line, and Substation Interconnections.

14 This language was added so the customer will have easy references to the
15 documents that lay out all requirements and expectations of the Company and
16 Customer.

17 OTP also updated what were previously number 13, now number 10. This
18 Term and Condition discusses insurance requirements for the Customer. OTP updated
19 this item to reference the ARSD chapter 20:10:36. OTP also added language that
20 allows for, additional umbrella liability coverage up to \$2,000,000 in appropriate
21 circumstances.

22 This language was added to protect OTP and its customers from the exposures
23 relating to uninsured liability claims for equipment over which OTP has limited
24 control.

25
26 Q. WHAT LANGUAGE ARE YOU REMOVING FROM THE TERMS AND
27 CONDITIONS SECTION OF SMALL POWER PRODUCER SCHEDULES,
28 SECTION 12.01 – 12.03?

29 A. OTP removed items in the Terms and Conditions section that was also covered in
30 either the Interconnection Agreement for Small Generator Facility Tier 1, Tier2, Tier 3
31 or Tier 4 Interconnection or OTPS’s Guidelines for Generation, Tie-Line, and
32 Substation Interconnections. The items removed were the last part of number 11 (now

1 number one), number 6, number 8, number 9, last sentence of number 13, number 14
2 and number 15. All these items are duplicative and therefore were removed.

3
4 **15. Water Heating Control Rider – Section 14.01**
5 **Rate Codes – 70-191 and 70-192**

6
7 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
8 OTP’S WATER HEATING CONTROL RIDER?

9 A. In addition to recommending some of the Consistent Rate Schedule Changes, OTP is
10 recommending to revise the language in the Availability, Term and Conditions for
11 Rate 191 and Terms and Conditions for Rate 192 paragraphs. The recommended
12 changes to these paragraphs provide a clearer description of the type of service and the
13 appropriate rate that applies to the service under this rate schedule.

14
15 **16. Large General Service Rider – Section 14.03**
16 **Rate Codes – 70-642 through 70-649**

17
18 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
19 OTP’S LARGE GENERAL SERVICE RIDER?

20 A. OTP made a few minor changes to the Large General Service Rider to add clarity for
21 the Customer and OTP’s personnel. OTP also made two other changes to this rate
22 schedule’s language. First, the Large General Service Rider currently contains
23 language that refers to the Baseline Demand periods of On-Peak and Off-Peak. OTP
24 is proposing to delete the language that refers to these specific Peak periods. The
25 Large General Service Rider’s language will now simply refer to Baseline Demands.
26 Second, for clarity, the administrative charge sections were moved to just under the
27 availability paragraph.

28
29 Q. WHY IS OTP RECOMMENDING DELETING LANGUAGE REFERRING TO
30 BASELINE DEMAND PERIODS OF ON AND OFF PEAK?

31 A. OTP is deleting the language that refers to specific Peak periods to make the Large
32 General Service Rider more flexible for both OTP and the customer. This change will

1 allow the Electric Service Agreement (ESA) to define time differentiated period(s) and
2 associated pricing.

3
4 **17. Controlled Service – Interruptible Load – Self Contained Metering**
5 **Rider – Section 14.05**
6 **Rate Codes – 70-190, 70-185 and 70-882**
7

8 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
9 OTP’S CONTROLLED SERVICE – INTERRUPTIBLE LOAD –
10 SELF CONTAINED METERING RIDER?

11 A. In addition to some of the Consistent Rate Schedule Changes, OTP is proposing the
12 following changes: modification of the language in the availability and the penalty
13 periods paragraphs.

14
15 Q. WHAT CLARIFICATION HAS BEEN ADDED ON THE APPLICATION OF THE
16 RIDER?

17 A. OTP has added language that describes when a customer may need to sign a
18 Controlled Service Agreement. Customers that do not have a back-up system that
19 automatically turns on during a control period are required to sign a Controlled
20 Service Agreement. This agreement requires the customer to acknowledge that the
21 customer has been advised of risks associated with the service by not having an
22 automatic back-up system.

23
24 Q. PLEASE EXPLAIN THE CHANGES TO THE PENALTY PERIODS.

25 A. OTP recommends non-substantive changes that modify and clarify the use of a dual
26 register meter for measuring penalty kWh’s.

27
28 **18. Controlled Service – Deferred Load Rider – Section 14.06**
29 **Rate Codes – 70-197, 70-195 and 70-883**
30

31 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
32 OTP’S CONTROLLED SERVICE – DEFERRED LOAD RIDER.

1 A. In addition to some of the Consistent Rate Schedule Changes, OTP is recommending
2 the following changes: modification of the language in the penalty periods and the
3 control criteria sections.

4
5 Q. PLEASE EXPLAIN THE CHANGES TO THE PENALTY PERIODS.

6 A. OTP recommends non-substantive changes that modify and clarify the language
7 describing the use of a dual register meter for measuring penalty kWh's.

8
9 Q. PLEASE EXPLAIN THE CHANGES TO THE CONTROL CRITERIA.

10 A. The changes proposed for the control criteria relate to the description of when other
11 approved loads may be controlled. The description of the control criteria has been
12 modified to specify that domestic water heating may be controlled for up to 14 hours
13 in a 24 hour period, which is measured from midnight to midnight. This change
14 provides a clearer description of the time period when domestic water heating may be
15 controlled.

16
17 **19. Fixed Time of Delivery Service – Section 14.07**
18 **Rate Codes 70-301, 70-884, 70-302, 70-885 and 70-303, 70-886.**
19

20 Q. PLEASE DESCRIBE THE CHANGES OTP IS PROPOSING WITH RESPECT TO
21 OTP'S FIXED TIME OF SERVICE RIDER.

22 A. In addition to some of the Consistent Rate Schedule Changes, OTP is recommending
23 the following changes: addition of a section on ancillary equipment and modification
24 of the language in the penalty periods.

25
26 Q. PLEASE EXPLAIN THE ADDITION OF THE ANCILLARY EQUIPMENT
27 SECTION TO THIS RIDER.

28 A. OTP has added language that allows minimal fan and pump load to be served under
29 the fixed time of delivery rider to allow for the operation of the controlled service
30 system. OTP included this language to address situations where equipment design or
31 separate wiring is not feasible, making this wiring structure necessary; and clarifies
32 that the total load served through this rider is intended to constitute minimal total load.

1 Additional language is included explaining that the exemption for pump and fan loads
2 does not include grain drying or circulation pumps and other equipment ancillary to
3 those activities, as these are significantly sized loads. Grain drying load is intended to
4 constitute a fully interruptible load with fans representing a significant portion of the
5 load.

6

7 Q. PLEASE EXPLAIN THE CHANGES TO THE PENALTY PERIODS.

8 A. OTP recommends non-substantive changes that modify and clarify the language of the
9 describing the use of a dual register meter for measuring penalty kWh's.

10

11 Q. DOES THIS CONCLUDE YOUR TESTIMONY?

12 A. Yes.

CUSTOMER AND RATE CLASS PROPOSED ALLOCATIONS AND REVENUES

Line No.	CCOSS Customer Classes	Proposed CCOSS-Based Class Increase	Proposed EPMC Method	Rate Classes	EPMC or Intra-Class Proposed Increase	Revenue 2009 Actual	2010 Revenue Proposed	Proposed Increase by Rate Class	2010 Revenue 100% Marginal Cost	2010 Proposed Revenue as % of 100% MC
1										
2	Residential	12.50%	Method 2	Residential Service	10.33%	\$7,837,567	\$8,732,090	11.41%	\$9,344,572	93.4%
3				Res. Demand Control	35.47%	741,732	919,622	23.98%	1,085,864	84.7%
4				Subtotal		\$8,579,299	\$9,651,711		\$10,430,436	92.5%
5	Farms	15.00%	N/A	Farm Service	CCOSS	\$594,499	\$683,674	15.00%	\$986,424	69.3%
6	General Service	7.50%	Method 1	Small General Service	7.75%	\$2,568,700	\$2,767,864	7.75%	\$2,727,705	101.5%
7				General Service	7.48%	3,732,945	4,012,302	7.48%	3,954,088	101.5%
8				GS Time of Use	0.00%	0	0	0.00%	0	N/A
9				Subtotal		\$6,301,645	\$6,780,167		\$6,681,793	101.5%
10	Large General Service	7.50%	Method 1	Large General Service	7.97%	\$8,112,682	\$8,759,166	7.97%	\$11,836,277	74.0%
11				LGS Time of Day including LGS Rider	5.78%	1,694,817	1,792,722	5.78%	2,422,509	74.0%
12				Standby Service	0.00%	0	0	0.00%	0	NA
13				Subtotal		\$9,807,499	\$10,551,888		\$14,258,786	74.0%
14	Irrigation	15.00%	Method 2	Irrigation	13.00%	\$17,370	\$19,629	13.00%	\$22,530	87.1%
15				Irrigation Time of Use	29.42%	2,404	3,111	29.42%	4,040	77.0%
16				Subtotal		\$19,774	\$22,740		\$26,570	85.6%
17	Lighting	10.00%	N/A	Lighting Energy Only	CCOSS	\$40,980	\$45,078	10.00%	N/A	N/A
18				Area Lighting	CCOSS	561,138	617,251	10.00%	N/A	N/A
19				Subtotal		\$602,118	\$662,329		N/A	0.0%
20	OPA	15.00%	Method 2	Municipal Pumping	14.91%	\$234,358	\$269,309	14.91%	\$349,799	77.0%
21				Civil Defense/Fire Sirens	36.99%	920	1,260	36.99%	1,901	66.3%
22				Subtotal		\$235,278	\$270,570		\$351,701	76.9%
23	Controlled Service Water Heating	16.00%	N/A	Water Heating	CCOSS	\$413,540	\$479,707	16.00%	\$544,488	88.1%
24	Controlled Service Interruptible	19.00%	Method 1	Large Dual Fuel	21.68%	\$251,251	\$305,729	21.68%	\$394,804	77.4%
25				Small Dual Fuel	17.84%	580,567	684,135	17.84%	883,459	77.4%
26				Subtotal		\$831,818	\$989,863		\$1,278,263	77.4%
27	Controlled Service Deferred Load	17.00%	Method 2	Deferred Load	19.79%	\$214,119	\$256,501	19.79%	\$274,734	93.4%
28				Fixed Time of Service	8.78%	72,788	79,180	8.78%	76,614	103.3%
29				Subtotal		\$286,907	\$335,681		\$351,348	95.5%
30				Total	9.96%	\$27,672,377	\$30,428,331	\$2,755,954	\$34,909,809	85.3%

Mr. David G. Prazak
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CURRENT RESPONSIBILITIES (2000 – Present)

Manage the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates, rate design

PREVIOUS POSITIONS

Otter Tail Power Company

2000– Present
1997-2000

Supervisor, Pricing
Senior Pricing Analyst

EPS Solutions

1990-1997

Associate I & II: Consultant in demand-side management planning, evaluation, and training

Northern States Power

1989-1990

Demand-Side Management (Intern): Aided in DSM activities

EDUCATION

Minnesota State University,
Moorhead

B.S., Energy Management, concentration in Industrial Technologies

Walden University

Currently enrolled, Masters of Public Administration

Section No.	Section description	Changes
Index		<ul style="list-style-type: none"> • All changes to the section descriptions have been made to be consistent with the appropriate sections changes of Otter Tail's General Rules and Regulations And Electric Rate Schedules. Specific descriptions of these changes are identified in the appropriate sections below.
1.00 – 8.02		<ul style="list-style-type: none"> • For clarification and consistency, the following changes were made to many sections of Otter Tail’s General Rules and Regulations. <ul style="list-style-type: none"> ○ Capitalized the first letter of words that are defined in Section 8.01 – Glossary. ○ In many cases the word "a" was replaced with "the" (or the word “the” was added) in front of the words “Customer” or “Company” ○ In several locations the word “premises” was changed with the phrase “service location.”
1.00	General Service Rules	
1.01	Scope of General Rules and Regulations	<ul style="list-style-type: none"> • In the last sentence, replaced the phrase "the Company's" with "Company" and added ".01" to "Section 8".
1.02	Application for Service	<ul style="list-style-type: none"> • Replaced “are” with "shall be” in the second to last sentence in the first paragraph. • Added the phrase “unless evidence is provided that the person is an emancipated minor” in the second sentence of the second paragraph. • Added the phrase “or it is determined that the Customer does not qualify for service under the current selected rate(s)” to the third sentence. • Added the phrase "initiates a request to" to the third sentence of the second paragraph. • Replaced the word “may” with “shall” in the third sentence of the second paragraph. • Added the phrase “unless it is determined that the Customer does not qualify for service under the current rate(s)” to the third sentence of the second paragraph.
1.03	Deposits, Guarantees and Credit Policy	<ul style="list-style-type: none"> • No changes

Section No.	Section description	Changes
1.04	Customer Connection Charge	<ul style="list-style-type: none"> • In the first paragraph, replaced the word "second" with the word "additional" in last sentence. • In the Connection Charge section, eliminated the last sentence. • The Temporary Meter Socket Detachment and Reattachment charge section has significant text revisions to better explain that offering. Also the final sentence was removed and incorporated earlier on in the paragraph. • In the “Additional Charges section, added a section that explains that "The Company is not required to perform a reconnection outside its normal business hours". And added text explaining “The overtime charge is equal to the average overtime cost the Company incurs for its service representatives.”
1.05	Forms	<ul style="list-style-type: none"> • Added the following sentence in paragraph 4 of the Electric Service Agreement and Irrigation Electric Service Agreement and in paragraph 7, 10 and 13 of the Outdoor Lighting and Municipal Service Agreement: “The Customer at this location is subject to all mandatory riders in effect at the time of the execution of this agreement, any riders approved by the Commission after the execution of this agreement, and any voluntary riders that the customer chooses to participate in during the entire term of this agreement.” • Electric Service Agreement – Section 3, changed the words “additional costs” and “cost” to “Excess Expenditures”. Changed “5.02” to “5.03”. Section 6, added “This agreement shall automatically terminate in the event the Customer discontinues all electric service or has its service disconnected by the Company for any reason. The termination of this agreement for any reason will not relieve Customer of any payments due to the Company for any services provided pursuant to this agreement and the Company’s tariffs, or for the full payment of amounts required pursuant to paragraph 7 of this agreement”. Section 7, replaced the words “in order to provide an adequate and proper net return on the additional investment to be made by” with “as required by” and added “Tariff for service extension costs” behind “the Company.” • Irrigation Agreement - Section 1, added the word “approved” and replaced the word “filed” with “approved”. Section 6, added two sentences that explains termination

Section No.	Section description	Changes
		<p>guidelines. Section 7, replaced the word “meet” with “metering”. Section 8, added “an annual” and “Special Facilities charges as identified in Section 5.03 of the General Rules and Regulations for”. Added “the Company’s total” and “is\$_____”. Added “Annual Fixed Charge is:” Deleted “Annual fixed charge for the term of this Agreement”. Added “paid in seven equal monthly payments”. Add “Or” between the two payment options. Added the words “paid in seven equal monthly payments”. Deleted paragraph beginning with “If applicable,”. Deleted section 9 and renumbered the remaining paragraphs.</p> <ul style="list-style-type: none"> • Outdoor Lighting and Municipal Service Agreement - Section 1, replaced the phrase “services identified in this Agreement” with “energy.” Added the word “approved” and added the sentence “These Terms shall include but not be limited to Customer’s payment for electric energy in accordance with the Company’s rate schedule as filed with and approve by the South Dakota Public Utilities Commission, or such superseding rate(s) as may be approved in the future. Deleted the last sentence. Section 2, added the words “one year” and deleted “(but in no event less than a minimum term of (1) one year). Added two additional sentences to the end to explain agreement termination guidelines. Section 3, added “Account No.” Section 15, replaced the words “additional costs” and “cost” with “Excess Expenditures” and changed “5.02” to “5.03”. • Summary Billing Contract – Removed the words “Public Service or Utilities” and “of the state where Customer’s service is provided”. Removed “for the accounts listed by” and “in Attachment 1” and “Service Worksheet”. Added the words “accounts to be included for.” Added “Services shall be attached to this contract. The terms and conditions of this contract are listed in Section 4.12 of the Company General Rules and Regulations. Customer agrees to either send in the most recent copy of all bills selected for summary billing OR complete the Summary Billing Service Worksheet”. Removed “Attachment 1” to the Summary Billing Service Contract and modified the Customer Authorization paragraph due to the removal of “Attachment 1”. Relocated and modified the last sentence to its own “Liability” section. Replaced the last sentence, in the Changes by Customer section, with “The change must be accepted by the Company”.

Section No.	Section description	Changes
		<ul style="list-style-type: none"> Controlled Service Agreement – Replaced the words “lower cost electricity” with “a reduced rate” in the second paragraph. Added “ly available” behind the word “operation” in the third paragraph. Added the word “non-automatic” in the fourth paragraph. Added “or other fixtures” to the sixth paragraph. In Section 1, added “(non-automatic) backup”, changed the word “fuel” to “system”, added the phrase “I plan to use a”, “I understand, agree to, and accept the risks or damage to my property in the event that there is no backup heating system, and “to take Controlled Service”. Electric Service Statement and Adjusted Electric Service Statement – Added Energy Efficiency Program as a billing component.
1.06	Reserved for Future Use	<ul style="list-style-type: none"> Added this new section for future use.
1.07	Reserved for Future Use	<ul style="list-style-type: none"> Added this new section for future use.
1.08	Reserved for Future Use	<ul style="list-style-type: none"> Added this new section for future use.
2.01	Assisting Customers in Rate Selection	<ul style="list-style-type: none"> No changes.
2.02	Service Classification	<ul style="list-style-type: none"> Removed the sentence “Rates designated General Service are available to any non-Residential Customer.” In the first paragraph, added "RESIDENTIAL SERVICE" to the beginning of the first paragraph, replace the words "premises" with "service location." Added "FARM SERVICE" heading and revised the last paragraph of this section to better describe the combination of Residential and Farm service and how the service is metered and billed.
3.01	Disconnection of Service	<ul style="list-style-type: none"> No changes.
3.02	Curtailement or Interruption of Service	<ul style="list-style-type: none"> In the first paragraph, first sentence, replaced the phrase "an emergency condition that" with “a” , changed the word “threatens” to “threat” and added the word “to”. Second sentence, removed the phrase "exercised without unreasonable preference,”.
3.03	Reserved for Future Use	<ul style="list-style-type: none"> No changes.

Section No.	Section description	Changes
3.04	Reserved for Future Use	<ul style="list-style-type: none"> No changes.
3.05	Continuity of Service	<ul style="list-style-type: none"> In the first sentence, replaced the phrase “make all reasonable efforts” with the word “endeavor”, replaced the word “will” with “does”, and added “uninterrupted or”. Second sentence, replaced “will” with “shall”, added the word “interruption” and “whatsoever”.
4.01	Meter and Service Installations	<ul style="list-style-type: none"> Changed “&” to “AND” in the main section title. In the first paragraph, replaced the phrase "one set of" with the word "the." Revised and eliminate text from the second paragraph to better define the Company and Customer responsibilities for wiring within the meter socket and CT cabinet. Added a paragraph which explains when the Company will require a wiring affidavit. In the last paragraph before “Meter Installation Requirements”, replaced the phrase "the Customer" with “a location not previously serviced”. In the first paragraph under “Meter installation Requirements”, added "Self-Contained" in the subtitle. Replaced the word “are” or “is” with “shall be” in several locations. Other text changes to the descriptions of the requirements of the Customer and the Company for Meter and Service Installations.
4.02	Meter Readings	<ul style="list-style-type: none"> First paragraph, added these words to the beginning, “Unless authorized by statute, rule, or other appropriate authority”. Replaced the word “are” or “is” with “shall be” in several locations. Third sentence – replaced the words “to complete and provide to the Company” with “an estimated bill will be rendered for that billing period”. Added the statement “an estimated reading for up to two months as arrangements are made for a Company representative to contact the Customer” and eliminated the next sentence. Last sentence in second paragraph, added “and when there is a change in occupancy of the premises.”
4.03	Estimated Billing	<ul style="list-style-type: none"> In the Section title, replaced the word "Readings" with "Billing".

Section No.	Section description	Changes
4.04	Meter Testing and Meter Failure	<ul style="list-style-type: none"> • In the first paragraph, removed the first parentheses in “(a)” and “(1),” etc., replacing with “a)” and 1), etc. • Replaced “(a)” with “1)” and “(b)” with “2)”. • Replaced “If the period of registration error is unknown, a billing adjustment will be applied to lesser period of (a1)” with “The refund or charge for both fast or slow Meters shall be based on corrected Meter readings for a period equal to”. Replaced “or (b)” with “but not to exceed”.
4.05	Access to Customer's Premises	<ul style="list-style-type: none"> • Replaced “premises” with “property” in the second paragraph.
4.06	Establishing Demands	<ul style="list-style-type: none"> • Replaced the word “are” with “shall be”, replaced the word "premises" with the phrase "service location" and replaced "portable Meter" with "an appropriate device".
4.07	Monthly Billing Period and Prorated Bills	<ul style="list-style-type: none"> • Replaced the word “is” with “shall be” in the second sentence. • Replaced the word “Charge” with “blocks” • Deleted the word “and” and replaced the words “components of the” with “and any other monthly charges or credits for the applicable” in the last sentence.
4.08	Electric Service Statement - Identification of Amounts and Meter Reading	<ul style="list-style-type: none"> • Add the phrase “Rate schedules or services will be billed and identified on electric service statements” at the beginning of the first paragraph. • Removed the phrase “of the face”. Replaced the word “bill” with “statement”. Eliminated the last sentence. • Replaced “Municipality” with “Governmental Unit”. • Eliminated the last paragraph.
4.09	Billing Adjustments	<ul style="list-style-type: none"> • In the Underbilled section, first paragraph – removed the words “and reissue corrected bills” and the word “period”. • In the Overbilled section, removed words “errors resulting in over charges” and replaced with “service during the period of the error,”
4.10	Payment Policy	<ul style="list-style-type: none"> • In the second paragraph, replaced the word “will may” or “will” with “shall”. • In the third paragraph, replaced “a” with “the” and “or more” with “greater than”. • In the fourth paragraph, removed “(a)”. Replaced “are” with “shall be”. • In the fifth paragraph, added “s” to the word “plan”.

Section No.	Section description	Changes
4.11	Even Monthly Payment (EMP) Plan	<ul style="list-style-type: none"> • In the first paragraph, replaced the word "premises" with the phrase "service location" and "those premises" with "that service location". • In the second paragraph, replaced the second and third sentences with "A debit balance for this settle-up month will roll into the new EMP amount and be collected over the next 12 months unless the debit balance is \$10 or less, in which case the amount will be collected on the next billing statement." In the last sentence replaced the words "the US Bank" with "a large regional bank." • In the third paragraph, eliminated the word "payment". • In the fourth paragraph, replaced the word "end" with "cancel".
4.12	Summary Billing Services	<ul style="list-style-type: none"> • Added the word "the" in several locations. • In the fourth paragraph - added "and other monthly charges for the applicable rates" to the end of the last sentence.
4.13	Account History Charge	<ul style="list-style-type: none"> • Added the phrase "by the Customer" and replaced the phrase "within a six month period" with "not to exceed \$100.00 per request set".
4.14	Combined Metering	<ul style="list-style-type: none"> • Replaced the word "premises" with "service location".
5.00	Standard Installation and Extension Rules	<ul style="list-style-type: none"> • Changed the title to "STANDARD INSTALLATION AND EXTENSION RULES" to better identify contents of this section. The contents of Section 5.01 through the Section 5.05 are a reorganization of Otter Tail's original Sections 5.01 through 5.05, which were approved in Otter Tail's most recent rate case.
5.01	Service Connection	<ul style="list-style-type: none"> • Entire contents of the original Section 5.05 were moved to Section 5.01. • As a result of moving the entire contents of Section 5.05 to Section 5.01, changed the subheading from "Extension Rules and Minimum Revenue Guarantee" to "Service Connection". • In the third paragraph, replace the word "on" with "at" and "premises" with "service location". • In the fourth paragraph, added the word "the" and replaced the word "are" with "shall be at". • In the seventh paragraph, replaced the word "may" with "shall".

Section No.	Section description	Changes
5.02	Voltage Classification	<ul style="list-style-type: none"> • The entire contents of the original Section 5.04 were moved to Section 5.02. • In the title of this Section, replaced the phrase "Standard Installation" with "Voltage Classification". • The first paragraph is the result of moving the second paragraph under service at secondary voltage section. This paragraph was also revised to clarify the voltage levels available to customers. • In the Service at Secondary Voltage section, revised the description of secondary voltages available to customers and who owns the system. Made the following changes: <ul style="list-style-type: none"> ○ Added the phrase “either 1) below 2,400 or 2)” ○ Replaced “120” with “2,400” and “12,470” with “15,000”. • A new sub heading of “Service at Primary Voltage” was added. • Removed the word “transformer” and “transformers and distribution primary”. Added “(including Distribution transformers, if any)”. Replaced “are” with “is”. • A new sub heading of “Service at Transmission Voltage” was added. In this section – added the word “service” in the first sentence. Then added “The availability of service at transmission voltage will be determined by the Company when requested”. Removed “where any substation and distribution primary systems are provided”. Revised the last section of this paragraph to more clearly explain service voltage incorporating some of the next paragraph, which is shown as deleted. Added text under 1) and 2) to continue defining this criteria. • The words “Service Installation” were relocated. • In the first paragraph under Service Installation, removed the word “permanent” and the phrase “a one-time charge of”. • In the second paragraph under Service Installation, in the first sentence, removed the phrase “a Distribution lateral”. In the next sentence, replaced the word “which” with “the Company facilities”. Further on in that paragraph added the phrase “schedule(s) the Customer is taking service under). Removed the word “this” and replaced “5.01” with “5.03”. • Removed the “Winter Construction” subtitle. • Relocated the “Service at Transmission Voltage” information.

Section No.	Section description	Changes
5.03	Facilities Definitions, Installations, and Payments	<ul style="list-style-type: none"> • The entire contents of the original Section 5.02 were moved to Section 5.03. • Section title - replaced the words "Temporary Service" with "Facilities, Definitions, Installations, and Payments". This change was made in the header. Deleted the sentence “For the purposes of Section 5.02, the following definitions apply:” Relocated the Standard Facilities definition to the beginning of this section. • In the definition of “Distribution Facilities”, or second paragraph, removed the words "primary and secondary voltage". Added the word "underground". Removed the "s" from the word "cable". Removed the word "trenches". Replaced “41.6 KV” with "41,600 volts". Added the word "the" before “Customer’s”. Added the words "point of connection”. Add the words “may also” and replaced the word “excluded” with “include a radial line rated equal to or greater than 41,600 volts dedicated to serve Customer on Transmission rates. Distribution Facilities exclude". Deleted the last sentence. • Third paragraph - removed the word "all". Added the word "underground". Removed the "s" from the word "cable". Replaced “41.6 KV” with "41,600 volts”. • Fourth paragraph – added the word “non-standard” in the first sentence. • Fifth paragraph – is new. Added the sentence “The Company is not obligated to provide any Special Facilities and may refuse to do so at its sole discretion”. • Added the subheading “Facilities Installations”. Throughout this section – replaced the word “City or Municipality” with Governmental Unit”. In the third paragraph under this Facilities Installation section, removed the word “initially” and the phrase “(including, but not limited to, lighting facilities other than those described in a rate rider)”, and the word “will”. Removed the phrase “for undergrounding of Distribution Facilities”. • In the Special Facilities in Public Right-Of-Way section, replaced “Municipality as a governing body of public right of way” and “Municipality” with “Governmental Unit” throughout this section. In the first paragraph, added “and not merely for the convenience for the local Governmental Unit, in connection with: 1) a present or future local government use of the right-of-way for a public project ; 2) the public health or safety; 3) the safety and convenience of

Section No.	Section description	Changes
		<p>travel over the right-of-way”. Removed the phrase “with construction on the public right of way”.</p> <ul style="list-style-type: none"> • Incorporated the fourth paragraph (shown as deleted) in other paragraphs in this section. • In the Underground Facilities Requirements section, in the first paragraph added the phrase “at the request of a Customer or Governmental Unit:” • In the second paragraph in this section, added “s” behind “Company”. • In the third paragraph in this section, added “s” behind “Customer” and replaced “Municipality” with “Governmental Unit” and added “the” before Company. • In the fourth paragraph in this section, added the phrase “and the undergrounding is requested by the Customer or ordered by a Governmental Unit” • In the fifth paragraph in this section, removed the phrase “by franchise or permit”. • In the sixth paragraph in this section, added the word “Where” to the beginning and replaced “Municipality” with “Governmental Unit”. • In the eighth paragraph, added the word “the” before Company. • In the Special Facilities Payments section, first paragraph added “or Governmental Unit” two times. • The next five paragraphs are either relocated text or additional text to better explain charges for Special and Excess Expenditures.

Section No.	Section description	Changes
5.04	Extension Rules and Minimum Revenue Guarantee	<ul style="list-style-type: none"> • The entire contents of the original Section 5.01 were moved to Section 5.04. • First paragraph – removed the word “Customer’s” and added “schedule(s) under which the Customer is taking service”. Removed the word “Customer’s”. Added the words “schedule(s) under which the Customer is taking service). Removed “t” from the word “not”. Replaced “or to” with “and”. Added “a deposit” and “including the service extension charges” • In the second paragraph, replaced the word “costs” with “extension charges”. • Third paragraph, added “three-year”. Removed “ed” from “contracted”. Added “when calculated based on actual usage”. Replaced the word “deficiency” with “difference between the guaranteed minimum and the actual usage”. Eliminated “and/or will be deducted from the Customer’s advance payment, and the balance of the advance payment, if any, will be refunded to the Customer with interest on the balance.”
5.05	Temporary Service	<ul style="list-style-type: none"> • The entire contents of the original Section 5.03 were moved to Section 5.05.
6.01	Customer Equipment	<ul style="list-style-type: none"> • In the first paragraph, eliminated the word “that” and added the words “equipment or” and “s” to the word system. Added the word “the” before Copmany. • In the last paragraph, replaced “(a” with “1”, “(b” with “2”, “(c” with “3”, “(d” with “4”, and replaced the number “2” with the number “3” in the number “5.03”.
6.02	Use of Service; Prohibition on Resale	<ul style="list-style-type: none"> • In the second paragraph, replaced the word “may” with “shall”.
7.01	Waiver of Rights or Default	<ul style="list-style-type: none"> • In the first paragraph, replaced the word “is” with “shall”.
7.02	Modification of Rates, Rules and Regulations	<ul style="list-style-type: none"> • Added the word “The” to the beginning of the first sentence. Replaced the words “are provided with” with “shall receive such”.

Section No.	Section description	Changes
8.01	Glossary	<ul style="list-style-type: none"> • Added definitions for Account, Customer, Governmental Unit, Megawatt, Seasonal Customer, Single-phase, Tariff (Tariff Schedules), and Three-phase. • Changed generally standard abbreviations for electrical units of measure. • Adjusted the definitions for Commission, Company, Distribution, Energy Charge, Kilowatt-Hour, South Dakota Public Utilities Commission (SDPUC), Transmission Service, and changed Municipality to Governmental Unit.
8.02	Definition of Symbols	<ul style="list-style-type: none"> • No changes
All sections 9.01 – 14.10	Electric rate schedules	<p>Consistent changes to all these rate schedules include:</p> <ul style="list-style-type: none"> • updated the Revision number. • In the Description boxes, changed from rate level “70” to rate level “71”. • In the Regulations section, replaced the word “tariff” with “electric rate schedule”, replaced the word “schedule” with “service” in some cases replaced the word “rider” with schedule, and in some cases changed the word “under” with the word “of”. • In the Mandatory and Voluntary Riders section, changed the text to be consistent on all rate schedules that contain this section. • Capitalized the first letter of words that are defined in Section 8.01 – Glossary.
9.01	Residential Service	<ul style="list-style-type: none"> • Revised the description of Seasonal Residential Service to better define the availability of seasonal service and the requirements for meter reading and billing. • Rate changes.
9.02	Residential Demand Control Service	<ul style="list-style-type: none"> • Rate changes.
9.03	Farm Service	<ul style="list-style-type: none"> • In the rate box, removed facilities charges based on transformer size for three-phase customers. All three-phase customers will have the same facilities charge regardless of the size of the transformers providing service. • Rate changes.

Section No.	Section description	Changes
10.01	Small General Service under 20 kW	<ul style="list-style-type: none"> • In the Application section, removed the words “energy for resale, nor for municipal” • Moved and modified the Terms and Conditions section to under the Definition of Seasons section. Changed language in this section now to read “<u>TERMS AND CONDITIONS:</u> The Customer may remain on the Small General Service schedule as long as Customer's maximum Demand does not equal or exceed 20 kW for more than two of the most recent 12 months. If the Customer achieves an actual Demand of 20 kW or greater for a third time in the most recent 12 months, the Customer will be placed on the General Service schedule (Section 10.02) in the next billing month.” • Added the Seasonal Small General Service section. • In the Determination of Demand section, added the phrase “Unless otherwise established,” and removed the phrase “An estimated or metered demand shall be used to establish the applicability of this schedule, at the option of the Company. This”. Added the phrase “Demand in” and “as measured by a Demand Meter”. • Rate changes.
10.02	General Service 20 kW or Greater	<ul style="list-style-type: none"> • In the APPLICATION OF SCHEDULE section, replaced the word “rate” with the word “schedule”. Removed the phrase “energy for resale, nor for municipal outdoor lighting” and replaced with “outdoor lighting.” • In the rate box, added “+ Demand” for Monthly Minimum, for the facilities charge, added the phrase “per Month per Annual maximum kW (minimum 20 kW per Month)” and added “Demand Charge per kW: (minimum 20 kW)” section with summer and winter rates. • For clarity on how demands are measured and billed, added Metered Demands, Adjustment for Excess Reactive Demand, and Determination of Billing Demand sections and revised the text in the Determination of Facilities Charge section. • Rate changes.
10.03	General Service - Time of Use	<ul style="list-style-type: none"> • The Section number was changed from 10.04 to 10.03. In the header, title and rate box replaced the word “Commercial” with “General”. • In the APPLICATION OF SCHEDULE section, removed the phrase “with a measured demand of at least 20 kW within the most recent 12 months.” • In the rate box, on the Monthly Minimum Bill line, added

Section No.	Section description	Changes
		<p>“+ Demand Charge”.</p> <ul style="list-style-type: none"> • In the rate box, on the Facilities Charge per Month added phrase “Per Annual maximum kW (minimum 20 kW per Month)” • In the rate box, on the Demand Charge per kW added “(minimum of 20 kW)” • Due to changing the billing for facilities charges, added sections for Metered Demands and Adjustment for Excess Reactive Demand. Relocated and changed the Determination of Facilities Charge section. • Relocated and replaced the Determination of Demand section with a Determination of Billing Demand section. • Removed the TERMS AND CONDITIONS • In the Definition of Declared, Intermediate and Off-Peak Periods by Season section, added the phrase “For all kW and kWh used during the” to the description of the Declared and Intermediate periods. Replaced the phrase “Weekdays or” with “Monday through”, removed the “s” from the word “Saturdays” and added the word “and” to the description of the Off-Peak period. • Rate changes.
10.04	Large General Service	<ul style="list-style-type: none"> • The Section number was changed from 10.03 to 10.04. • In The APPLICATION OF SCHEDULE section removed the phrase “energy for resale, nor for municipal”. • In the rate boxes, on the Demand Charger per kW: line, added “(minimum of 80 kW)” • For clarity on how demands are measured and billed, added a Metered Demands section and revised the text in the Adjustment for Excess Reactive Demand, Determination of Billing Demand and Determination of Facilities Charge sections. • Rate changes.
10.05	Large General Service - Time of Day	<ul style="list-style-type: none"> • For clarity on how demands are measured and billed, added Metered Demand. • Changed the text in the Adjustment for Excess Reactive Demand section to read “ADJUSTMENTS FOR EXCESS REACTIVE DEMANDS: For billing purposes, the Metered Demands may be increased by one kW for each whole ten kVar of Reactive Demand in each period in excess of 50% of the Metered Demand in kW”. • Changed the text in the Determination of Billing Demand section to read “DETERMINATION OF BILLING

Section No.	Section description	Changes
		<p>DEMAND: The Billing Demand shall be the Metered Demand adjusted for Excess Reactive Demand”.</p> <ul style="list-style-type: none"> • Changed the text in the Determination of Facilities Charge section to read “DETERMINATION OF FACILITIES CHARGE: The Facilities Charge Demand will be based on the grater of 1) 80 kW or 2) the larges to the moset recent 12 monthly Metered Demands adjusted for Excess Reactive Demand.” • Removed CONTRACT PERIOD & AGREEMENT section. • Rate changes.
11.01	Standby Service	<ul style="list-style-type: none"> • In the Application of Schedule section, replaced the title “Application of Schedule” with “Availability”. Added the phrase “including Definitions and Useful Terms”, removed the phrase “This schedule”. • Replaced the last sentence in the definition of Backup Demand with a separate definition of Backup Demand Charge. • Changed Excess Facility Investments label to “Excess Distribution Facility Investments” and added “Distribution” in definition. • Removed the definition of Special Minimum Demand to be consistent with this provision being removed from Section 10.04 and 10.05. • Rate changes.
11.02	Irrigation Service	<ul style="list-style-type: none"> • In the Application of Schedule section, added the word “Irrigation” • In the rate box in the Facilities Charge and Monthly Charge sections, changed the word “Facilities” to Fixed”. • Changed the title of the “Facilities Charge” section to “Fixed Charge”. • In the Definition of Declared, Intermediate and Off-Peak Periods by Season section, added the phrase “For all kW and kWh used during the” to the description of the Declared and Intermediate periods. Replaced the phrase “Weekdays or” with “ Monday through”, removed the “s” from the word “Saturdays” and added the word “and” to the description of the Off-Peak period. • Rate changes.

Section No.	Section description	Changes
11.03	Outdoor Lighting - Energy Only Dusk to Dawn	<ul style="list-style-type: none"> • In the Description box, removed the Sign Lighting line. These customers will be moved to Outdoor Lighting – Non-Metered – Energy Only rate code 71-749. And added the phrase “Energy Only”. • In the Equipment and Service Ownership section, added the phrase “be UL approved or” and replaced the phrase “the Company’s specifications” with the phrase “National Electric Code Standards”. • Rate changes.
11.04	Outdoor Lighting Dusk to Dawn.	<ul style="list-style-type: none"> • In the Description box, Replaced the phrase “Street and Area” with the word “Outdoor”. • In the Application of Schedule section, removed the phrase “, including a village, town or city.”. • In the rate box, added an asterisk to all mercury vapor type lights to provide a clear reference to the fact that mercury vapor lights are no longer allowed for new installations. Also removed the word “Mercury”. • In the Seasonal Customers section, added the word “Seasonal” in the last paragraph. • In the Underground Service section, removed the phrase “or sign”, and added the * on the MV-6PT”*” to reference the Mercury Vapor fixtures are no longer allowed for new installations. • Rate changes.
11.05	Municipal Pumping	<ul style="list-style-type: none"> • In the second paragraph of the “APPLICATION OF SCHEDULE” section removed the words “and treating plants”. In the second paragraph added the word “appropriate”. Removed the phrase “except that where service through a meter is for electric space heating only the energy on this meter shall be added to the pumping meter for billing purposes.” because this provision would require additive metering and also does not allow the customer to have the electric heat on a controlled service rate. Removed the third paragraph “The Company retains the authority to allow totalizing at locations where allowed electric space heating load is metered separately from the pumping load. In all other cases the monthly minimum shall apply to each meter providing service under this tariff.” • In the Rate box added “Maximum kW per month:” under the Facilities Charge per Month. • Added the following sections due to changes in rate design for billing for the facilities charge based on demand rather

Section No.	Section description	Changes
		<p>than levels of kWh use: Metered Demands, Adjustment for Excess Reactive Demand, Determination of Billing Demand and Determination of Facilities Charge.</p> <ul style="list-style-type: none"> • Rate changes.
11.06	Civil Defense - Fire Sirens	<ul style="list-style-type: none"> • In the Service Conditions section changed “200” to “150” and added “No additional transfer Capacity shall be provided without additional charges.” • Rate changes.
12.00	Purchase Power Riders - Availability Matrix	<ul style="list-style-type: none"> • In the title, replaced “APPLICABILITY” with “AVAILABILITY”. • Removed the checks from the Irrigation Service line because Irrigation service is seasonal and would not apply.
12.01	Small Power Producer Rider Occasional Delivery Energy Service	<ul style="list-style-type: none"> • In the Availability section, replaced the word “Available” with the phrase “This rider is available”. And added the words “small” and “SQF” and “certified”. • In the Payment Schedule section, removed the phrase “Effective :”. • Rate changes.
12.02	Small Power Producer Rider Time of Delivery Energy Service	<ul style="list-style-type: none"> • In the Availability section, added the words “small”, “SQF” and “certified”. • Rate changes.
12.03	Small Power Producer Rider Dependable Service	<ul style="list-style-type: none"> • In the Availability section, added the words “small”, “(SQF)” and “certified”. • In the Payment Schedule section, removed the phrase “For deliveries commencing on”. • Rate changes.
13.00	Mandatory Riders - Applicability Matrix	<ul style="list-style-type: none"> • Added the words “by any” to the first paragraph. • Added Mandatory mark on “Fire Sirens – Civil Defense 11.06” under “Energy Efficiency Partnership (EEP) Cost Recovery Rider 13.04” • Added a check mark for “Real Time Pricing Rider 14.02” under “Fuel Adjustment Clause Rider 13.01”. • Removed Mandatory mark on “Air Conditioning Control Rider 14.08” under “Fuel Adjustment Clause Rider 13.01” • Added Mandatory mark on “Voluntary Renewable Energy Rider 14.09” and “Released Energy Rider 14.11” under “Energy Efficiency Partnership (EEP) Cost Recovery Rider 13.04”
13.01	Fuel Adjustment	<ul style="list-style-type: none"> • Added section “RULES AND REGULATIONS: Terms and conditions of this electric rate schedule and the General

Section No.	Section description	Changes
	Clause Rider	Rules and Regulations govern use of this rider.” <ul style="list-style-type: none"> • Added section “MANDATORY AND VOLUNTARY RIDERS: The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply and by any Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rider. See Sections 12.00, 13.00, and 14.00 of the South Dakota electric rates for the matrices of riders.”
13.02	Reserved for Future Use	
13.03	Reserved for Future Use	
13.04	Energy efficiency Partnership (EEP) Cost Recovery Rider	<ul style="list-style-type: none"> • Changed the title “Application of Schedule” to “Application of Rider” and added the phrase “, except for Standby Service, Section 11.01.”
14.00	Voluntary Riders - Availability Matrix	<ul style="list-style-type: none"> • Removed check mark from Sections 10.01, 11.02 & 11.05 for the Released Energy Rider. • Changed the title of “Water Heating Controlled Service” to “Water Heating Control Rider”. • In the title of Section 14.05, corrected the misspelled word “Containted” to “Contained”. • Added a check mark under Section 14.09 for General Service – Time of Use, now Section 10.03. • Removed check mark under Section 14.09 for Section 11.02 – Irrigation Service. • Added check mark under Section 14.02 for General Service – Time of Use, now Section 10.03. Removed check mark under Section 14.11 for 11.05 – Municipal Pumping Service.
14.01	Water Heating Control Rider	<ul style="list-style-type: none"> • In the Availability section, changed replaced the phrase “residential or non-residential purposes” with the phrase “Customers with electric water heaters requesting controlled service; refer to Section 14.00 for the Voluntary Riders – Availability Matrix”. • In the Rate box added “Separately metered” to water heating – control service – 191 and changed “controlled” to “control.”

Section No.	Section description	Changes
		<ul style="list-style-type: none"> • In the Water Heating Credit 192 box added the words “Control service” to title and added “Monthly Credit:” and removed “A credit per month shall be applied to all bills having direct control water heating, except the credit shall not reduce the monthly billing to less than the Monthly Minimum Charge.” • Under the Terms and Conditions for Rate 191, added the word “this”, removed the number “191” • Under the Terms and Conditions for Rate 192, added the phrase “Water Heating Credit Control Service” to the title, removed the phrase “for taking service on this rider”, replaced the phrase “monthly bill” with the phrase “the water heating”. Added the phrase “, except the credit shall not reduce the monthly billing to less than the Monthly Minimum Bill.” • Rate changes.
14.02	Real Time Pricing Rider	<ul style="list-style-type: none"> • No changes other than some of the consistent changes to all rate schedules listed above.
14.03	Large General Service Rider	<ul style="list-style-type: none"> • Moved the Administrative Charge section. • Changed all instances of the phrase “On-Peak Baseline Demand and Off Peak Baseline Demand” to “Baseline Demand(s)”.
14.04	Controlled Service - Interruptible Load CT Metering Rider (Large Dual Fuel)	<ul style="list-style-type: none"> • In the Availability section, replaced the phrase “residential or non-residential service to any” with the phrase “Customers with”. Removed the phrase “used for both heating and cooling”. • In the Rate section, added the sentence “During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.” • In the Penalty Periods section, replaced the word “peak” with the word “penalty”. • Rate changes.
14.05	Controlled Service - Interruptible Load Self-Contained Metering Rider (Small Dual Fuel)	<ul style="list-style-type: none"> • In the Availability section, replaced the phrase “residential or non-residential service to any” with the phrase “Customers with”. Removed the phrase “used for both heating and cooling”. Replaced the word “heat” with the phrase “conditioned air and/or water”. In the second paragraph removed the words “or heating loops” • moved “The Company requires a primary electric heating Customer served on an interruptible rate to complete a Controlled Service Agreement acknowledging that the Customer is aware of the potential for property damage”

Section No.	Section description	Changes
		<ul style="list-style-type: none"> • In the Rate section, added the sentence “During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.” • In the Penalty Period section added the sentence “Installation of a dual register Meter will be at the option of the Company” and replaced the word “peak” with the word “penalty”. • Rate changes.
14.06	Controlled Service Deferred Load Rider	<ul style="list-style-type: none"> • In the Availability section, replaced the phrase “residential or non-residential service to any” with the phrase “Customers with”. Removed the words “Subject to the exception below,” Replaced the word “heat” with the phrase “conditioned air and/or water”. • In the Rate box, added the sentence “During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.” • In the Penalty Period section, moved the last sentence to after the second sentence. Added the sentence “Installation of a dual register Meter will be at the option of the Company” and replaced the word “peak” with the word “penalty”. • In the Control Criteria section, added the sentence “Domestic water heating may be controlled up to 14 hours in a 24-hour period, as measured from midnight to midnight.” • In the Equipment Supplied section, replaced “Otter Tail” with “The Company” • Rate changes.
14.07	Fixed Time of Service Rider (Commonly identified as Fixed TOS)	<ul style="list-style-type: none"> • In the title, the Description box and the rate boxes replaced the word “Delivery” with the word “Service”. Changed “TOD” to “TOS”. • In the Availability section, added a paragraph that describes how Electric fans, pumps, and other ancillary, equipment will be wired and used during the control period. Removed the sentence “Rider threshold determinations will be made based on connected load and service level and will be independent of actual registered demand or energy usage.” • In the Rate section, added the sentence “During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above.” to each rate box. • In the Penalty Period section moved “Installation of a dual

Section No.	Section description	Changes
		register Meter will be at the option of the Company” and added “When a dual register Meter is installed” <ul style="list-style-type: none"> • In the Control Criteria section, replaced the word “In” with the word “During”. • Rate changes.
14.08	Air Conditioning Control Rider (Commonly identified as CoolSavings)	<ul style="list-style-type: none"> • No other changes other than some of the consistent changes to all rate schedules listed above. • Rate change
14.09	Voluntary Renewable Energy Rider (Commonly identified as "TailWinds Program")	<ul style="list-style-type: none"> • No changes other than some of the consistent changes to all rate schedules listed above. • Rate change
14.11	Released Energy Rider Access Program (REAP) Rider	<ul style="list-style-type: none"> • Moved Mandatory and Voluntary Riders section to below Availability section.
14.12	Bulk Interruptible Service Application and Pricing Guidelines	<ul style="list-style-type: none"> • No changes other than some of the consistent changes to all rate schedules listed above.
15.00	Retail Electric Service to Communities (Alphabetically listed by city name)	<ul style="list-style-type: none"> • No changes
16.00	Summary of Contracts with Deviations	<ul style="list-style-type: none"> • No changes

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Otter Tail Power Company Marginal Cost of Electric Service Study

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INTRODUCTION

I. INTRODUCTION

Otter Tail Power Company (OTP) retained NERA Economic Consulting to prepare an estimate of the company's marginal costs of supplying electricity for the years 2010-2014. All costs are expressed in 2010 dollars. This report describes the methods for estimating marginal generation, transmission, distribution and customer-related costs and presents summary tables of the results.

What are marginal costs? Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must answer the question: What are the additional costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand and number of customers? Because the cost of additional consumption may differ depending upon the time of the change in output, it is important to estimate time-differentiated marginal costs of electricity.

Our method for estimating marginal costs is based on the system planning process, and takes into account the wholesale market and transmission access arrangements specific to the environment where the utility operates. We determine the marginal cost of electricity by examining the utility's planning processes to determine what drives new investment and purchase/sale decisions and how changes in consumption affect utility system operations. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurements can be made.

COSTING/PRICING PERIODS

II. COSTING/PRICING PERIODS

OTP requested that we summarize the marginal costs by the periods shown below.

Table 1. Costing/Pricing Periods

Summer: June – September	
Peak:	Monday - Friday, 1 pm - 7 pm
Shoulder:	Monday - Friday, 9 am - 1 pm and 7 pm - 10 pm Weekends, 9 am - 10 pm
Off-Peak:	Monday - Friday, 10 pm - 9 am Weekends, 10 pm - 9 am
Winter: October – May	
Peak:	Monday - Friday, 7 am - 12 noon and 5 pm - 9 pm
Shoulder:	Monday - Friday, 6 am - 7 am, 12 noon - 5 pm and 9 pm - 10 pm Weekends, 6 pm - 10 pm
Off-Peak:	Monday - Friday, 10 pm - 6 am Weekends, 10 pm - 6 pm

COSTING/PRICING PERIODS

Table 2. Illustration of Costing/Pricing Periods

SEASON DEFINITION		COSTING PERIOD: WINTER (1)				COSTING PERIOD: SUMMER (2)			
Month	Inclusion	Hour Ending	Weekday	Saturday	Sunday	Hour Ending	Weekday	Saturday	Sunday
January	1	1	O	O	O	1	O	O	O
February	1	2	O	O	O	2	O	O	O
March	1	3	O	O	O	3	O	O	O
April	1	4	O	O	O	4	O	O	O
May	1	5	O	O	O	5	O	O	O
June	2	6	O	O	O	6	O	O	O
July	2	7	S	O	O	7	O	O	O
August	2	8	P	O	O	8	O	O	O
September	2	9	P	O	O	9	O	O	O
October	1	10	P	O	O	10	S	S	S
November	1	11	P	O	O	11	S	S	S
December	1	12	P	O	O	12	S	S	S
		13	S	O	O	13	S	S	S
		14	S	O	O	14	P	S	S
		15	S	O	O	15	P	S	S
		16	S	O	O	16	P	S	S
		17	S	O	O	17	P	S	S
		18	P	O	O	18	P	S	S
		19	P	S	S	19	P	S	S
		20	P	S	S	20	S	S	S
		21	P	S	S	21	S	S	S
		22	S	S	S	22	S	S	S
		23	O	O	O	23	O	O	O
		24	O	O	O	24	O	O	O

Off-Peak = O
Shoulder = S
Peak = P

MARGINAL GENERATION COSTS

III. MARGINAL GENERATION COSTS

OTP actively participates in the Midwest ISO (MISO) electricity wholesale market, buying and selling on a short-term and long-term basis to minimize the cost of serving its retail customers and maximize profits on off-system (wholesale) sales. OTP builds generating units to meet load growth because it expects the cost of the new unit to be lower than the market price. However the value of that unit's generation (and OTP's opportunity cost) is the market price. Thus, in a competitive electricity market, the marginal cost of generation is defined by market prices.

An increment of native load in any hour requires the utility to purchase more energy or sell less to the market. Thus the market price of energy is the basis for OTP's marginal energy cost.¹ An increment of load in some hours may require the utility to reduce the size of a capacity sale, arrange for additional generating capacity, pay penalties for not meeting capacity requirements, or incur market prices for energy that include a capacity (or shortage) element, depending on the timing of the load increase and the rules in effect.

MISO establishes minimum planning reserve requirements for its members. As a result, separate markets for energy and capacity have developed, with generators recovering some of their fixed costs in the capacity market.² Under these market arrangements, the marginal cost of generation in a given hour is the sum of the spot price of energy and the hourly equivalent of the market price of capacity.

In applying the conceptual framework outlined above, three specific steps must be followed:

1. estimate the marginal energy cost for each hour based on a forecast of spot market energy prices;
2. estimate the market price of capacity in the MISO region;
3. convert the capacity market prices into hourly marginal capacity costs, taking into account OTP's probability of peak and the specific MISO resource adequacy rules, as explained in Section III.B.

¹ The market prices must be adjusted for cash working capital and losses to produce marginal costs at the customer meter level.

² There is often some capacity element in the spot price of energy as well, as impending shortages drive the market-clearing price above the marginal running cost of the marginal unit.

MARGINAL GENERATION COSTS

A. Marginal Energy Cost

OTP provided forward monthly peak and off-peak prices³ at the OTP node for the period January 2010 through December 2014. OTP based these prices on the forward monthly prices developed by Intercontinental Exchange (ICE) for the Cinergy node which is the main trading node in MISO. OTP developed the forward prices at the OTP node using a forecast of

the price difference between the Cinergy and OTP nodes, based on 24 months of historical hourly price differentials.

We shaped these monthly energy peak and off-peak market price forecasts using monthly averages of day-ahead hourly prices at the OTP node, covering the period January 1, 2007 to December 31, 2008. Table 3 shows the resulting forecast of energy market prices for 2010-2014, averaged over the costing periods described in Section II.

Table 3. 2010 – 2014 Market Price Forecast by Costing Period

		Summer Season			Winter Season		
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
		----- (2010 Cents per kWh) -----					
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	2010	6.0870	4.1381	1.0433	5.0889	3.5291	2.2678
(2)	2011	6.4087	4.3906	1.2343	5.3940	3.8084	2.4341
(3)	2012	6.6690	4.5875	1.3749	5.5688	3.9833	2.6101
(4)	2013	6.9686	4.8975	1.6942	5.7665	4.2039	2.9301
(5)	2014	7.1495	5.0697	1.8587	5.9584	4.3753	3.0122

To convert these to energy marginal costs at customers' meters, it is necessary to make two adjustments. The first adjustment is a small factor to account for the cost of financing working capital necessary because OTP must pay for energy purchases before it is reimbursed by its customers. The cost of financing the balance includes a cost-of-capital component (OTP's estimated weighted-average cost of capital) and an income tax component that accounts for the fact that the equity portion of the financing is taxable. Second, the market prices must be adjusted for marginal energy losses incurred in moving the energy through OTP's local transmission and distribution systems. Marginal energy losses are higher when energy is delivered at lower voltage levels. In addition, losses increase with the square of the load (all

³ MISO On-peak period definition is Monday – Friday, hours ending 7-22. Off-peak is all other hours.

MARGINAL GENERATION COSTS

else equal) at any given voltage level. Thus there is a different loss adjustment factor for each hour and for each voltage level of service. The derivation of these marginal energy loss factors is described in Section VII.E. The market prices and marginal energy costs after these two adjustments are shown on Table 4.

Table 4. 2010-2014 Marginal Energy Cost by Costing Period⁴

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
2010						
Market Price	6.09	4.14	1.04	5.09	3.53	2.27
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	6.56	4.44	1.11	5.55	3.83	2.45
Primary	7.00	4.71	1.16	5.98	4.11	2.62
Secondary	7.27	4.88	1.20	6.26	4.28	2.73
2011						
Market Price	6.41	4.39	1.23	5.39	3.81	2.43
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	6.91	4.71	1.31	5.88	4.13	2.63
Primary	7.37	5.00	1.38	6.34	4.43	2.81
Secondary	7.65	5.18	1.42	6.63	4.62	2.92
2012						
Market Price	6.67	4.59	1.37	5.57	3.98	2.61
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	7.19	4.92	1.46	6.07	4.32	2.82
Primary	7.67	5.22	1.54	6.54	4.63	3.01
Secondary	7.96	5.41	1.58	6.85	4.83	3.13
2013						
Market Price	6.97	4.90	1.69	5.77	4.20	2.93
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	7.51	5.26	1.80	6.29	4.56	3.16
Primary	8.01	5.58	1.89	6.77	4.89	3.38
Secondary	8.32	5.78	1.95	7.09	5.10	3.51
2014						
Market Price	7.15	5.07	1.86	5.96	4.38	3.01
Marginal Energy Costs Adjusted for Losses and Working Capital for Service at:						
Transmission	7.71	5.44	1.97	6.49	4.75	3.25
Primary	8.22	5.77	2.07	7.00	5.09	3.47
Secondary	8.54	5.98	2.13	7.32	5.31	3.61

⁴ Loss information provided by OTP, 01/28/2010. The energy prices are quoted at the OTP Hub and thus the losses applied are from that location to customer's meters at each voltage level of service. For more information on how the losses are applied, see Section VII E.

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B. Marginal Generation Capacity Cost

Starting in June 2009, MISO Resource Adequacy rules (Module E) require each load-serving entity (LSE) to demonstrate that it has sufficient planning reserves to meet its monthly peak loads plus a reserve margin. The required reserve margin is calculated by MISO based upon regional loss-of-load expectation (LOLE) studies that take into account the load diversity within MISO. One component of the reserve margin is applied to load and the other component is based on generator performance over the past three years. In planning year 2009/2010, the effective reserve requirement for OTP was 16%.⁵ This margin will be revised for the next planning year which begins June 1, 2010. Because the new reserve requirement is not yet determined, this report uses 16%.

By March 1 of each year, each LSE is required to submit a forecast of its monthly peak loads for the following planning year, along with a resource plan that shows how the company plans to meet the monthly peak demands plus the required reserve margin. The LSE does not need to demonstrate that it is in compliance with next month's resource adequacy requirements until 30 days in advance. Capacity transactions are negotiated bilaterally in the MISO region, as there is no central clearing house for these transactions, except for the voluntary capacity auctions. A voluntary capacity auction is held a little over one month prior to the start of each month to allow LSEs to acquire capacity as needed to meet the planning requirement. To date, these capacity auctions have shown little trading activity and substantial price volatility.⁶

In estimating OTP's short-term marginal capacity cost we have assumed that OTP is able to contract for sufficient capacity at least a month in advance so that it is unlikely to use the MISO voluntary capacity auction. Given MISO Resource Adequacy rules, OTP's marginal generation capacity cost in any hour on a planning basis is a function of: (1) the monthly capacity price, (2) the required reserve margin, and (3) the probability that the hour is OTP's peak hour in the month. If the load growth takes place in OTP's monthly peak hour, the opportunity cost for OTP is the cost of arranging for additional capacity to meet the requirement, or the lost revenue from selling less surplus capacity in the market.

Forecasts of monthly capacity contract prices, i.e., prices that would reflect monthly capacity transactions, were not available. We based our monthly capacity prices on the annual capacity

⁵ The reserve margin applied to OTP's generation was 10.65%. OTP's generation was discounted by its actual reliability performance, which was estimated as 9.23%. However, two of OTP's plants reported data in such a manner that their maximum ratings were under-reported, so the OTP generation applied a margin of 10.65% as opposed to the regional average of 7.34%. The average reserve rate for MISO for 2009 was 12.69%. Of this amount, 5.35% was applied to load, so the effective reserve requirement for OTP was 16% (10.65% + 5.35%).

⁶ For example, for the August 2009 planning month, only 110 MW of capacity (out of an installed capacity of almost 130,000 MW) cleared at a price of \$1/MW-month. In comparison, 864 MW of capacity cleared for the June 2009 planning month at a price of \$50/MW-month, while the July 2009 auction cleared 364 MW at a price of \$10,015/MW-month.

MARGINAL GENERATION COSTS

price forecasts in OTP's Integrated Resource Planning (IRP). These prices reflect what OTP expects to pay for year-round capacity purchases. However, the value of capacity varies throughout the year. In order to allocate the year-round capacity prices to seasons, we used the relationship between expected summer (May through September) and winter (October through April) capacity contract prices provided by OTP for each year of the period 2010-2014.

Although the market value of capacity also varies across the months within a season, because this study aggregates costs into a summer and winter season, we did not attempt to determine separate capacity values for each month. We treated each month within the season as having the same capacity price⁷ and allocated the monthly cost to hours based on monthly probabilities of peak.⁸ The relative monthly probabilities of peak were calculated using OTP's hourly native loads for the period July 2004 through June 2009.

Assuming that the MISO Resource Adequacy rule requires a 16-percent reserve margin, the marginal capacity cost to OTP in a given hour under the new MISO Resource Adequacy requirements can be expressed algebraically as follows:

$$MCC_{h,m} = RPP_{m,h} \cdot 1.16 \text{ MCP}_m$$

where:

- $MCC_{h,m}$ = marginal capacity cost in hour h and month m;
- MCP_m = market capacity price per kW-month in month m;
- $RPP_{m,h}$ = relative probability that hour h is OTP's monthly peak in month m.

The marginal capacity costs, including losses and working capital, expressed on a per-kWh basis and averaged over the hours within each costing period, are shown on Table 5. These hourly costs can be summed across the hours in a period to yield a marginal cost per kW, as shown in Table 6.

⁷ However, it should be noted that we assigned May a winter capacity price so that the capacity seasons matched those in the marginal cost study (i.e. summer includes June through September). The May's share of the seasonal price differential between winter and summer was then spread across the four summer months.

⁸ An hour with low probability of being OTP's monthly peak hour has almost zero marginal capacity cost, because no additional capacity requirement would be triggered if load grew in that hour.

MARGINAL GENERATION COSTS

Table 5. 2010-2014 Marginal Generation Capacity Cost by Period (cents/kWh)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
2010						
Marginal Capacity Costs	0.697329	0.065423	0.001167	0.144908	0.033025	0.002456
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	0.759713	0.071299	0.001267	0.159704	0.036606	0.002738
Primary	0.818147	0.076808	0.001360	0.174022	0.040121	0.003019
Secondary	0.855417	0.080322	0.001418	0.183346	0.042433	0.003205
2011						
Marginal Capacity Costs	0.949296	0.089062	0.001589	0.248403	0.056613	0.004210
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	1.034222	0.097062	0.001725	0.273769	0.062751	0.004694
Primary	1.113770	0.104561	0.001851	0.298312	0.068777	0.005175
Secondary	1.164506	0.109345	0.001931	0.314295	0.072739	0.005494
2012						
Marginal Capacity Costs	1.619879	0.151975	0.002711	0.401897	0.091595	0.006811
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	1.764798	0.165626	0.002943	0.442936	0.101526	0.007594
Primary	1.900538	0.178422	0.003158	0.482644	0.111276	0.008373
Secondary	1.987115	0.186587	0.003295	0.508504	0.117687	0.008889
2013						
Marginal Capacity Costs	2.644687	0.248122	0.004426	0.626059	0.142683	0.010610
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	2.881288	0.270409	0.004805	0.689988	0.158153	0.011830
Primary	3.102903	0.291301	0.005156	0.751844	0.173341	0.013043
Secondary	3.244252	0.304630	0.005379	0.792128	0.183328	0.013847
2014						
Marginal Capacity Costs	2.772145	0.260080	0.004639	0.629394	0.143443	0.010666
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	3.020148	0.283441	0.005037	0.693663	0.158995	0.011893
Primary	3.252444	0.305339	0.005405	0.755849	0.174264	0.013112
Secondary	3.400606	0.319312	0.005638	0.796348	0.184304	0.013921

MARGINAL GENERATION COSTS

Table 6. 2010-2014 Marginal Generation Capacity Cost by Period (\$/kW-month)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2010 Dollars per kW-month)					
	(1)	(2)	(3)	(4)	(5)	(6)
2010						
Marginal Capacity Costs	\$0.9115	\$0.1739	\$0.0039	\$0.2830	\$0.0616	\$0.0085
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	\$0.9931	\$0.1895	\$0.0043	\$0.3119	\$0.0683	\$0.0095
Primary	\$1.0694	\$0.2041	\$0.0046	\$0.3398	\$0.0749	\$0.0105
Secondary	\$1.1182	\$0.2135	\$0.0048	\$0.3580	\$0.0792	\$0.0111
2011						
Marginal Capacity Costs	\$1.2409	\$0.2367	\$0.0053	\$0.4851	\$0.1056	\$0.0146
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	\$1.3519	\$0.2580	\$0.0058	\$0.5346	\$0.1171	\$0.0163
Primary	\$1.4559	\$0.2779	\$0.0062	\$0.5825	\$0.1283	\$0.0180
Secondary	\$1.5222	\$0.2906	\$0.0065	\$0.6137	\$0.1357	\$0.0191
2012						
Marginal Capacity Costs	\$2.1174	\$0.4039	\$0.0091	\$0.7848	\$0.1709	\$0.0236
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	\$2.3068	\$0.4402	\$0.0099	\$0.8649	\$0.1894	\$0.0264
Primary	\$2.4843	\$0.4742	\$0.0106	\$0.9424	\$0.2076	\$0.0291
Secondary	\$2.5974	\$0.4959	\$0.0111	\$0.9929	\$0.2196	\$0.0309
2013						
Marginal Capacity Costs	\$3.4570	\$0.6595	\$0.0148	\$1.2225	\$0.2662	\$0.0368
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	\$3.7663	\$0.7187	\$0.0161	\$1.3473	\$0.2951	\$0.0411
Primary	\$4.0559	\$0.7742	\$0.0173	\$1.4681	\$0.3234	\$0.0453
Secondary	\$4.2407	\$0.8097	\$0.0180	\$1.5468	\$0.3421	\$0.0481
2014						
Marginal Capacity Costs	\$3.6236	\$0.6913	\$0.0156	\$1.2290	\$0.2676	\$0.0370
Marginal Generation Capacity Cost, Adjusted for Losses and Working Capital for Service at:						
Transmission	\$3.9478	\$0.7533	\$0.0169	\$1.3545	\$0.2967	\$0.0413
Primary	\$4.2514	\$0.8115	\$0.0181	\$1.4759	\$0.3252	\$0.0455
Secondary	\$4.4451	\$0.8487	\$0.0189	\$1.5550	\$0.3439	\$0.0483

MARGINAL TRANSMISSION COST

IV. MARGINAL TRANSMISSION COST

OTP's transmission system consists of the Company's networked transmission, including 345 kV, 230 kV, 115 kV, 69 kV and 41.6 kV facilities. Otter Tail's network transmission greater than 100 kV has been transferred to the functional control of the Midwest ISO and included as part of the Midwest ISO's regional transmission expansion plan. Otter Tail retains control of its transmission facilities below 100 kV.

The costs of all facilities defined as transmission that were in service as of June 2008 within a control area are recovered at the wholesale level in the FERC-approved MISO Network Integration Transmission Service rate (NITS). Effective February 4, 2006, FERC introduced the Network Upgrade Charge (NUC) rate, which recovers the costs of new transmission facilities above 100 kV.⁹ The costs of these new projects are allocated to sub-regions and pricing zones following the Midwest ISO's "Regional Expansion Criteria and Benefits" method (RECB) as approved by FERC.¹⁰ The costs of facilities at or below 100 kV are recovered in the NITS. Both NITS and NUC rates are assessed on the basis of an LSE's monthly peak demands.¹¹

From the point of view of OTP, the marginal cost of transmission is the financial effect of changes in its monthly peaks. OTP does not write itself a check to pay for the use of the OTP Pricing Zone transmission facilities to serve its native load (the NITS charge).¹² However, both calculations of the MISO NITS and NUC charges assign to OTP a MISO transmission owners' transmission revenue requirement based on the allocation factors and billing determinants specified in the FERC-approved tariffs. Therefore, these charges are a financial marginal cost to OTP.

A. Network Integration Transmission Service Rate

The 2009 NITS rate, which recovers the costs of existing transmission facilities within the OTP Pricing Zone, is \$3,945.24/MW-mo. The NITS rate is charged to each transmission user¹³ in the OTP Pricing Zone based on their monthly peak loads. The Otter Tail NITS currently recovers the annual transmission revenue requirements for the Great River Energy (GRE) facilities located in the OTP Pricing Zone and for OTP transmission facilities. Missouri River

⁹ In practice, costs of new facilities above 100 kV with a project cost below \$5 million will be recovered in the NITS rate.

¹⁰ The RECB cost allocation methodology is specified in Attachment FF of the MISO TEMT. The Commission conditionally approved RECB I on February 3, 2006 and RECB II on March 15, 2007. 114 FERC ¶ 61, 106 and 118 FERC ¶ 61, 209, respectively.

¹¹ MISO rules (Section 34 of TEMT Modules, pages 331-332) call for these rates to be based on demands at the time of the MISO pricing zone's monthly peaks, but in practice individual transmission user monthly peaks are used instead.

¹² See *Midwest ISO*. 122 FERC 61,081 (2008).

¹³ Except for certain grandfathered transmission agreements.

MARGINAL TRANSMISSION COST

Energy Services (MRES) has applied to become a transmission owner of the Midwest ISO and the bulk of their transmission facilities are located in the OTP Pricing Zone.

To estimate the NITS charges beyond 2009, NERA estimated the annual increase in NITS revenue requirement associated with OTP's applicable new transmission projects, using OTP budgets for 115-kV (below \$5 million), 41.6 and 69 kV projects expected to come into service in the period 2010-2014, plus one GRE transmission project¹⁴ below \$5M that will go into the OTP NITS zonal rate by 2013. We applied MISO's estimates of annual carrying charges to the budget figures to compute an annual incremental revenue requirement for the OTP Pricing Zone NITS.

To compute an incremental rate, we divided the additional annual OTP NITS revenue requirement, stated in 2010 dollars, by a forecast of the sum of OTP's, GRE's, and NSP's 12 monthly peaks in each year, following MISO Attachment O procedures.¹⁵ We then added the current NITS rate adjusted by load growth¹⁶ and stated in 2010 dollars, to obtain a forecast of the total OTP NITS rate in each year, shown below in Table 7.

B. Network Upgrade Charge Rate

Forecasting a NUC is rather complex under the new RECB cost-sharing mechanism. Projects rated below 345 kV down to 100 kV, at a cost greater than \$5M, are allocated on a zonal basis. For all new projects rated 345 kV and above, with a project cost of \$5M or greater, 20% of the costs are allocated on a system-wide basis. The remaining 80% of the costs are allocated to planning sub-regions (West, Central and East) and pricing zones under a method that differs between economic and reliability projects.¹⁷

- For economic projects (RECB II), the sub-regional 80% cost allocation is based on the net present value of the economic benefit associated with each sub-region, as determined by a power flow analysis. The cost is then allocated to each individual pricing zone within the sub-region based on each zone's contribution to MISO's 12 CPs.
- For reliability projects (RECB I), 80% of the costs are allocated to individual pricing zones based on MISO's analysis of "Line Outage Distribution Factors" (LODF).

¹⁴ Addition of a new North Perham 115/41.6 kV substation.

¹⁵ For the forecast of OTP's 12 CPs we applied the expected growth in OTP 12 CP forecast (after load management) for the period 2009 – 2014, provided by OTP. For the forecast of GRE's 12 CPs we applied the peak load growth rates forecast in GRE's 2008 Resource Plan for the period 2009 – 2014. Finally, NSP's 12 CPs are forecasted to be 300 MW throughout the period given that information about expected load growth is not available.

¹⁶ Load growth every year reduces the per-kW impact of the current revenue requirement in the NITS charge.

¹⁷ To qualify for regional cost sharing under the RECB postage stamp rate, both Baseline Reliability Projects and Regionally Beneficial Projects must include facilities 345kV and above. For transmission projects rated below 345-kV, all costs get allocated on a zonal basis.

MARGINAL TRANSMISSION COST

As a result, the total NUC transmission revenue requirement allocated to the OTP Pricing Zone is the sum of the system-wide allocation, the sub-regional allocation percentages, and the individual LODF allocations corresponding to new projects.¹⁸ The total dollar revenue requirement amount is then divided by the sum of 12 CPs in the OTP zone to establish the corresponding NUC rate.

Attachment GG of the MISO OATT sets forth the method for calculating and collecting the charges associated with Network Upgrades and for distributing the revenues associated with such charges. Otter Tail did not have a NUC for 2009 as there were no cost-shared eligible projects in 2008. OTP submitted an Attachment GG for 2010 for FERC approval. If FERC accepts OTP's transmission rate filing Attachment GG revenue requirements will be part of 2010 NUC.¹⁹

MISO MTEP 06, 07, 08, and 09 Expansion Plans, Appendix A-2²⁰, include the shared project cost allocations by pricing zone and year, excluding the costs allocated to interconnecting generators. To estimate the NUC charges corresponding to the OTP Pricing Zone for the period 2010 - 2014, we took MISO's projections of the NUC-related annual incremental transmission revenue requirements that have been allocated to OTP's pricing zone from MTEP06, MTEP07, MTEP08, and MTEP09 for the period 2010-2014, restated in 2010 dollars.

We divided the annual revenue requirements from the expected project costs allocated to OTP pricing zone by the combined projections of OTP, GRE, and NSP 12 monthly peak forecast in each year. The results are shown in Table 7.

Table 7. Summary of 2010 – 2014 NITS and NUC charges in OTP Pricing Zone

	2010	2011	2012	2013	2014
	----- (2010 \$/kW-mo.) -----				
(1) NITS charges (\$/kW-mo)	\$4.1988	\$4.2748	\$4.1113	\$4.1214	\$4.1200
(3) NUC charges (\$/kW-mo)	\$3.0169	\$3.2295	\$4.2151	\$4.0858	\$3.9919
(4) Total OTP Transmission Charges (\$/kW-mo)	\$7.2157	\$7.5043	\$8.3264	\$8.2071	\$8.1119

¹⁸ For transmission associated with a new generator interconnection, 50% of the cost is to be paid by the generator, while the remaining 50% allocation is split similar to that noted for RECB I and II such that for projects 345 kV or greater, the costs are allocated 20% system-wide and 100% sub-regional basis and projects below 345 kV are allocated 80% to pricing zones pursuant to the LODF analysis.

¹⁹ MISO had not completed its allocation of the Attachment GG revenue requirements to the various pricing zones by the time the MC report was due. As a result, we did not include an estimate of 2010 Attachment GG in our NUC rate projections.

²⁰ NUC revenue requirements were based on MISO MTEP06, MTEP07, MTEP08, and MTEP09 RECB, with estimated Annual Charges for Allocated Project Cost by Pricing Zone. Provided by JoAnn Thompson, OTP and Kathy Brewster, MISO.

MARGINAL ANCILLARY SERVICE COSTS

C. Marginal Financial Transmission Cost

The MISO NITS and NUC charges are constant every month, as they reflect 1/12 of the applicable revenue requirement per kW. Because these charges are assessed on the basis of a transmission user's monthly peak demands, we identified marginal transmission cost responsibility within each month by estimating the relative probability of a given hour's being the monthly peak. We estimated these probabilities using the sum of the OTP and GRE native hourly loads for the period 7/1/2004 – 6/30/2009.

Table 8 shows the resulting time-differentiated marginal transmission costs for year 2010 by costing period, after adjustments for losses between the OTP system boundary and OTP customers' meters (using estimates of marginal energy losses at the time of each monthly peak) and cash working capital. The same marginal transmission costs stated on a per kW basis are shown in the summary tables at the end of the report. Transmission costs for other years covered by the study are shown in the Appendix.

Table 8. 2010 Time-Differentiated Marginal Transmission Costs

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Marginal Transmission Service Costs	4.3783	0.5466	0.0143	2.9710	0.5354	0.1252
<u>Marginal Transmission Charges by Voltage Level, Adjusted for Losses</u>						
(2) Transmission	4.7567	0.5948	0.0155	3.2707	0.5933	0.1393
(3) Primary	5.1086	0.6399	0.0167	3.5601	0.6501	0.1533
(4) Secondary	5.3321	0.6685	0.0174	3.7484	0.6874	0.1625

V. MARGINAL ANCILLARY SERVICE COSTS

MISO implemented ancillary services markets (ASM) in January 2009. Prior to January 2009, all ancillary services for Otter Tail were self-provided. The costs of ancillary services are also marginal financial costs to OTP.

Two types of ancillary services provided via these markets are Regulation and Operating Reserves (Spinning and Supplemental). OTP pays an hourly rate that is the total cost of each of these services procured by the MISO divided by the total hourly MISO load. OTP provided an average annual cost for each type of service covering the period January 6, 2009 to September 28, 2009. A forecast of the hourly or annual cost of these services for future years was not available. We assumed that the average annual cost for each ASM would continue at the 2009

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level and applied an inflation adjustment of 3.25 percent to convert this rate to 2010 dollars. We applied losses at each service voltage level and working capital. The results are shown on Table 9 below.

Table 9. 2010 Annual Marginal Ancillary Service Costs

	Regulating Reserve ----- (1)	Operating Reserves	
		Spinning Reserve (2010 Cents per kWh) ----- (2)	Supplemental Reserve ----- (3)
(1) Annual Ancillary Service Cost	0.971583	0.602980	0.048528
<u>Annual Ancillary Service Cost by Voltage Level, Adjusted for Losses and Working Capital</u>			
(2) Transmission	1.027806	0.637873	0.051336
(3) Primary	1.071360	0.664904	0.053511
(4) Secondary	1.096008	0.680201	0.054742

VI. MARGINAL DISTRIBUTION COSTS

Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Marginal cost studies have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components.

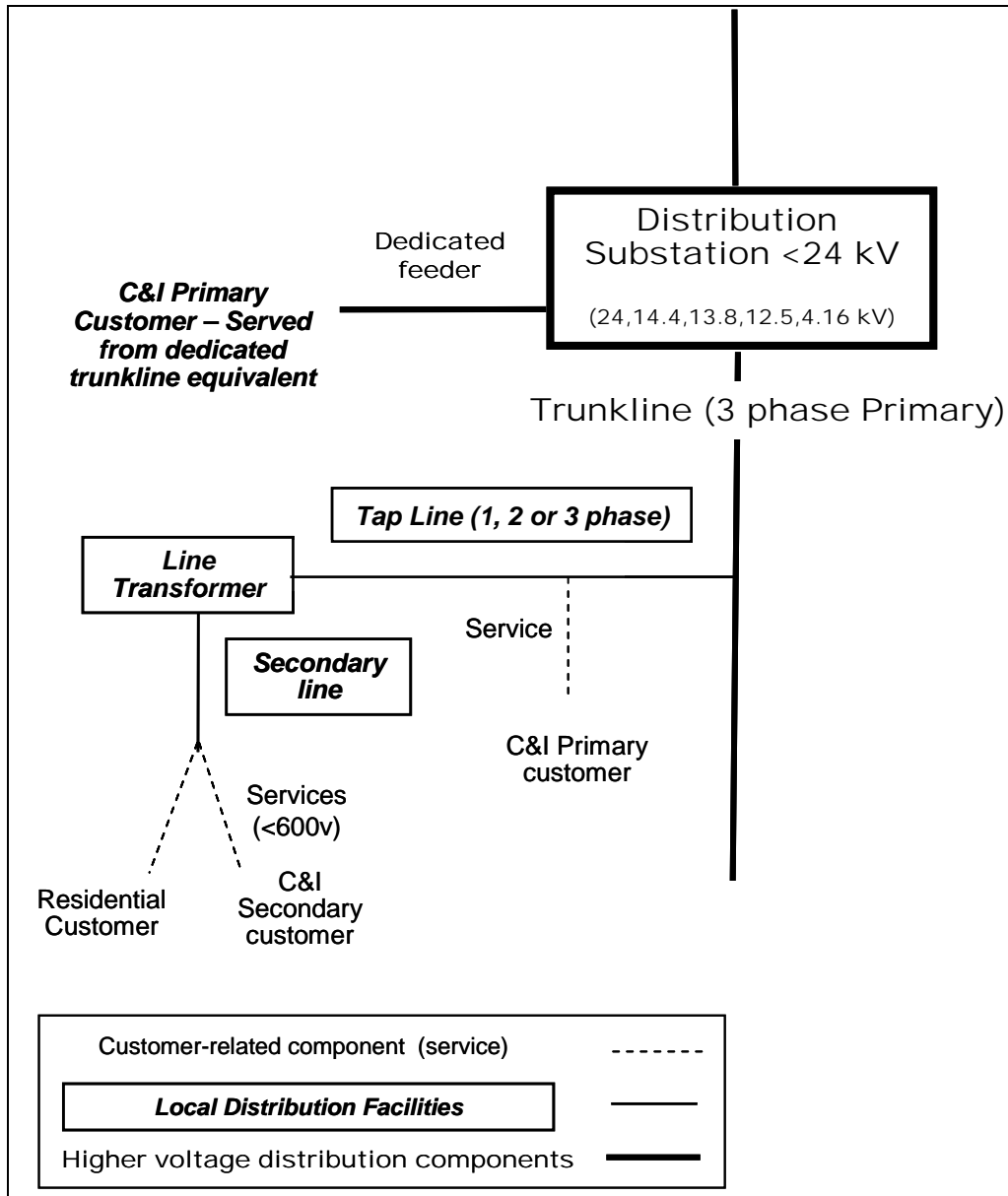
In fact, for most distribution systems, this two-part segmentation of distribution equipment is not consistent with the cost drivers, because it ignores the fact that there are two types of demand that determine distribution capacity requirements for a particular customer – design (or contract) demand and near-term demand at time of likely neighborhood peaks. The diagram below is a simplified representation of OTP’s distribution system and the configurations of typical customer connections. The various components are categorized as:

- higher voltage distribution components (shown as bold lines and boxes): distribution substations and primary trunkline feeders.
- local distribution facilities: secondary lines, primary-to-secondary transformers and switchgear and primary taps (shown as solid boxes);

MARGINAL DISTRIBUTION COSTS

- dedicated feeders used by some large primary customers (shown as a bold line);²¹ and
- customer-related service drops (shown as dashed lines).

Illustration of OTP's Distribution System



OTP adds distribution substations as load grows, either from connection of new customers or growth by existing customers. The trunkline feeders from the substation to the point where the

²¹ This study does not calculate separate marginal costs for such customers.

MARGINAL DISTRIBUTION COSTS

line branches to create a primary tap line also must be upgraded or rerouted as load grows. Because these more extensively shared, higher voltage distribution components are expanded as customer loads grow in critical hours, they are time-differentiated.

Local distribution facilities are designed using engineering design standards that take into consideration the number of customers and the *maximum expected* loads (or “design demands”) of customers who will eventually use those facilities, over the life of the facilities. For example, on average twice as much capacity is built into the local distribution system to serve an apartment with all electric appliances as one with gas appliances. Local distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, taking into consideration the expected long-term peak demand by the customer.

Because the marginal cost of local distribution facilities is incurred based on design demand, and does not vary with a customer’s actual peak load from month to month, these costs are computed as a fixed monthly cost per kW of design (or contract) demand. If necessary, design demand can be represented by some proxy, such as transformer capacity, contract capacity or actual peak in the past 12-24 months.

The service drop in most cases serves a single customer. The service, along with the meter and associated equipment such as current transformer (not shown in the diagram), is treated as part of the marginal customer cost for each class.

A. Distribution Substation and Trunkline Feeder Costs

To estimate the marginal cost of typical distribution substation and trunkline feeder expansion per kW of demand, we identify the cost of budgeted growth-related projects of this type (excluding any replacement projects that do not add capacity) and the load growth that is driving the need for the additional capacity. Using OTP’s capital budgets, we calculated the sum of all future growth-related investment for the period 2010-2014. We divided this sum (in 2010 dollars) by the estimated addition to distribution substation non-coincident peak demand over the same period.²² The marginal investment per kW is shown on Table 10.

²² OTP was only able to provide its non-coincident peak demand for the period 2004-2006. We estimated OTP’s non-coincident peak demand for the period 2010-2014 by calculating the average ratio of the non-coincident peak demand to the coincident peak demand for 2004-2006 and then applied that ratio to the forecasted coincident peaks (2010-2014).

MARGINAL DISTRIBUTION COSTS

Table 10. Distribution Substation and Trunkline Feeder Investment

(1) Investment in Growth-Related Additions to Distribution Substation Plant, 2010-2014 (Thousands of 2010 Dollars)	\$13,633
(2) Estimated Additions to Distribution Substation Non-coincident Demand, 2010-2014 (MW)	147.83
(3) Marginal Investment in Growth-Related Distribution Substation Facilities per Non-Coincident Kilowatt (2010 Dollars) (1) / (2)	\$92.22

1. Distribution Substation Marginal O&M Expenses

Distribution O&M expenses depend on the amount of plant in service. The addition of distribution plant to meet increments in customers or design load or peak substation load gives rise to increased O&M expenses as well. Distribution O&M expenses are, therefore, marginal costs. OTP’s FERC Form 1 filings provide 2004-2008 distribution O&M expenses by FERC account. Expenses for individual components (e.g., meters, substations, etc.) were allocated a proportional share of the general overhead O&M categories.²³ The trends in recent average levels of each category of distribution O&M were the starting point for our estimates of marginal O&M expenses.

The 2004-2008 distribution substation O&M expenses, plus associated overheads, were divided by estimates of the sum of non-coincident peak demands at the substations and converted to 2010 dollars, as shown on Table 11. After reviewing the trend in expense per kW (in constant dollars), we used the average of the 2004-2008 values as our estimate of marginal substation O&M expenses.

²³ These general accounts consist of Operation Supervision and Engineering and Maintenance Supervision and Engineering, and Miscellaneous Maintenance Expense.

MARGINAL DISTRIBUTION COSTS

Table 11. Distribution Substation O&M Expense per kW

Year	Total Distribution Substation Expenses (^{'000} Dollars)	Estimated Substation Noncoincident Peak (kW)	Substation Expenses Per kW of Substation Noncoincident Peak Loads (Dollars) (1) / (2)	Weighted Labor and Materials Cost Index (2010=1.00)	Substation Expenses Per kW of Substation Noncoincident Peak Loads (2010 Dollars) (3) / (4)
	(1)	(2)	(3)	(4)	(5)
(1) 2004	1,684	793,636	2.12	0.76	2.78
(2) 2005	1,870	807,232	2.32	0.80	2.88
(3) 2006	2,143	836,949	2.56	0.84	3.04
(4) 2007	2,360	856,956	2.75	0.89	3.08
(5) 2008	2,200	905,578	2.43	0.95	2.55
(6) Estimated Annual Distribution Substation O&M Costs (Average of 2004-2008 Values)					\$2.87

2. Time-differentiation of Marginal Distribution Substation Costs

Only load growth when capacity is strained triggers additions to the higher voltage distribution system. We analyzed hourly loads on a sample of representative OTP distribution substations for the years 2003-2007.²⁴

We estimated the relative probability of peak for months, day-types (weekdays, Saturday, and Sunday) and hours for each substation, taking into account the higher carrying capability of this equipment in cold temperatures. We then calculated weighted averages of these individual substation relative probabilities of peak, with weights representing the estimated number of customers served by substations similar in size and peak season to the sample substations. The period assignment factors are shown on Table 12.

²⁴ The 2003 data was excluded for two of the representative distribution substations because of irregular or missing data in that year.

MARGINAL DISTRIBUTION COSTS

Table 12: Probability of Peak for Higher-Voltage Distribution Investment

		Relative Probability of System Peak
<u>Summer Season</u>		
(1)	Peak	36.77%
	Shoulder	25.49%
(2)	Off-Peak	0.33%
(3)	Subtotal	62.59%
<u>Winter Season</u>		
(4)	Peak	14.27%
	Shoulder	5.42%
(5)	Off-Peak	17.73%
(6)	Subtotal	37.41%
(7)	Total	100.00%

B. Local Distribution Facility Costs

1. Local Distribution Facility Investment

OTP developed estimates of the typical investment in secondary lines, transformers, and a portion of primary taps for various types and sizes of customers, by applying its standard distribution cost estimation to a range of typical customer characteristics.²⁵

Because the marginal cost of local distribution facilities is incurred based on design demand, and does not vary with a customer’s actual peak load from month to month, we computed these costs as a monthly cost per kW of design (or contract) demand. We used the transformer capacity divided by the number of customers served from that transformer as the estimated design demand.

The distribution facilities investments for residential and non-residential customer categories are shown on Table 13 (stated in 2010 dollars). Retail customers that take service at a

²⁵ OTP also used this approach to estimate the cost of customer service drops.

MARGINAL DISTRIBUTION COSTS

transmission voltage pay up front for the cost of facilities to tap into the OTP transmission system, and so are excluded from this analysis.

Table 13 also shows the lighting equipment investment per lamp, provided by OTP, covering four lighting configurations.

Table 13. Marginal Distribution Facilities Investment per kW of Design Demand or per Light

Customer Class	Average Investment per kW	Average Investment per lamp
	(1)	(2)
	(2010 Dollars)	
Residential		
(1) Urban	\$147.76	
(2) Rural	\$268.13	
(3) Apartment, Gas	\$126.61	
(4) Apartment, Elec	\$73.86	
(5) Farm	\$296.89	
Small Commercial		
(6) Stand-Alone customer, overhead	\$37.90	
(7) Stand-Alone customer 3ph, overhead	\$60.30	
(8) Shared-customer 3ph, overhead	\$69.04	
(9) Stand-Alone customer, underground	\$111.21	
(10) Shared-customer 3ph, underground	\$179.44	
Large Commercial (Secondary)		
(11) 101-150kVa, 3ph	\$94.74	
(12) 151-300kVa, 3ph	\$54.14	
(13) 301-500kVa, 3ph	\$45.84	
(14) >501 kVa, 3ph	\$24.45	
(15) Very Large Commercial (Secondary TOU)	\$25.91	
Large Commercial (Primary)		
(16) 3000 kVa (LGS), 3ph	\$7.18	
(17) 5000 kVa (LGS TOU), 3ph	\$4.55	
Lighting		
(18) Area Light 1 HPS 9 (no pole), underground		\$1,387.15
(19) Area Light 1 HPS 9 (no pole), overhead		\$1,248.71
(20) Street Light - (no light, no pole), underground		\$767.08
(21) Street Light - (no light, no pole), overhead		\$634.44

MARGINAL DISTRIBUTION COSTS

2. Local Distribution Facility Operation and Maintenance

We reviewed the 2004-2008 local distribution facilities O&M expenses, and separated line-related expenses into primary and secondary categories on the basis of miles of circuit. We divided the expenses for each voltage level by estimates of total design demand of customers using those facilities. Total design demand was the product of customer counts and per-customer design demand estimates by customer category, developed from load survey data. We used the 2008 value as our estimate of marginal distribution facilities O&M expense.

Table 14. Distribution Facilities O&M Expense per kW of Design Demand

Year	Distribution Line O&M Expenses (’000 Dollars)	Weighted Labor and Materials Cost Index (2010=1.00)	Weighted Distribution Line O&M Expenses (2010 \$)	Total Estimated Design Demand (kW)	Line O&M Expense per kW of Design Demand (2010 \$)	
					Secondary (1)/(2) x 0.32	Primary (1)/(2) x 0.54
	(1)	(2)	(3)	(4)	(5)	(6)
(1) 2004	5,071	0.76	6,649	1,828,287	\$1.18	\$1.97
(2) 2005	5,873	0.80	7,314	1,924,131	\$1.23	\$2.06
(3) 2006	7,254	0.84	8,600	1,959,734	\$1.42	\$2.37
(4) 2007	8,619	0.89	9,632	2,023,113	\$1.54	\$2.57
(5) 2008	8,446	0.95	8,884	2,141,966	\$1.35	\$2.24
(6)	Estimated Distribution Facilities O&M (2008 Value)				\$1.35	\$2.24
(7)	Loss Adjustment Factor for Use of Primary Lines by Secondary Customers					1.0478
(8)	Loss Adjusted Estimated Primary Lines O&M Expenses for Secondary Customers Line (6) * Line (7)					\$2.35
(9)	Total Estimated Distribution Facilities Line O&M for a Secondary Customer. Line (6) in Col.(5) + Line (8)					\$3.70

MARGINAL DISTRIBUTION COSTS

C. Meter and Service Costs

1. Meter and Service Investment

OTP provided the installed cost of a typical meter (including current transformer, if applicable) and service drop for customer categories. The typical meter (and associated equipment) and service drop investments, stated in 2010 dollars are shown on Table 15.

MARGINAL DISTRIBUTION COSTS

Table 15. Investment per Customer in Meters and Services

Customer Class		Meter	Services	Total
		Investments per customer		
		-(2010 Dollars)-		
		(1)	(2)	(3)
Residential				
R-01	(1) Residential	\$77.02	\$370.52	\$447.54
R-03	(2) Residential Controlled Demand	\$375.00	\$370.52	\$745.52
R-91	(3) Residential Water Heat Controlled	\$257.01	\$0.00	\$257.01
I-02	(4) Residential Controlled Dual Fuel	\$253.65	\$0.00	\$253.65
I-03	(5) Residential Controlled Service Deffered Load	\$343.91	\$0.00	\$343.91
I-04	(6) Residential Fixed Time Of Delivery	\$343.91	\$0.00	\$343.91
M-22	(7) Street and Area Lighting	\$0.00	\$0.00	\$0.00
	(8) Flood Lighting	\$0.00	\$0.00	\$0.00
	(9) Sign Lighting	\$0.00	\$0.00	\$0.00
	(10) Energy-Only Street And Area Lighting - Metered	\$77.02	\$0.00	\$77.02
	(11) Energy-Only Street And Area Lighting - Non-Metered	\$0.00	\$0.00	\$0.00
Commercial and Industrial				
G-01	(12) General Service	\$332.82	\$522.28	\$855.10
F-61	(14) Farm Service	\$343.91	\$403.34	\$747.25
C-02	(15) Large Commercial Service			
	Secondary	\$1,238.58	\$22,198.26	\$23,436.85
	Primary	\$6,794.56	\$22,862.22	\$29,656.78
C-03	(16) Large General Service (Real Time Pricing) Primary	\$6,794.56	\$22,862.22	\$29,656.78
C-09	(17) Large General Service (Time Of Use) Primary	\$6,794.56	\$22,862.22	\$29,656.78
R-91	(18) Commercial Water Heat Controlled	\$257.01	\$0.00	\$257.01
I-01	(19) Large Commercial Controlled Dual Fuel	\$1,521.57	\$0.00	\$1,521.57
I-02	(20) Small Commercial Controlled Dual Fuel	\$253.65	\$0.00	\$253.65
I-03	(21) Small Commercial Controlled Service Deffered Load	\$340.95	\$0.00	\$340.95
I-04	(22) Small Commercial Fixed Time Of Delivery	\$340.95	\$0.00	\$340.95
I-06	(23) Bulk Interruptible Service	\$6,794.56	\$22,862.22	\$29,656.78
M-03	(24) Irrigation Service	\$935.53	\$370.52	\$1,306.05
M-04	(25) Commercial Time Of Use	\$1,139.23	\$22,862.22	\$24,001.45
	(26) Street and Area Lighting	\$0.00	\$0.00	\$0.00
	(27) Flood Lighting	\$0.00	\$0.00	\$0.00
	(28) Sign Lighting	\$0.00	\$0.00	\$0.00
	(29) Energy-Only Street & Area Lighting - Metered	\$77.02	\$0.00	\$77.02
	(30) Street & Area, Flood and Sign Lighting	\$0.00	\$0.00	\$0.00
	(31) Other Public Authority	\$299.89	\$1,692.69	\$1,992.58

MARGINAL DISTRIBUTION COSTS

2. Meter and Service Operation and Maintenance Expenses

The meter O&M per weighted customer (using frequency of meter testing as weights) increased significantly over in the past two years. We used the average over the period 2006-2008 as the estimate of the marginal level of these expenses, as shown on Table 16. Table 17 multiplies the result by the class weights to yield annual meter O&M by class.

Table 16. Meter O&M Expense per Weighted Customer

<u>Year</u>	<u>Total Meter Operation & Maintenance Expenses</u> (000's Dollars)	<u>Average Number of Customers</u>	<u>Weighted Average Number of Customers</u> (2) x 1.61	<u>Meter Expense Per Weighted Customer</u> (Dollars) [(1) x 1000]/(3)	<u>Weighted Labor and Materials Cost Index</u> (2010=1.00)	<u>Meter Expense Per Weighted Customer</u> (2010 Dollars) (4)/(5)
	(1)	(2)	(3)	(4)	(5)	(6)
(1) 2004	1,314.91	170,154	273,827	4.80	0.76	6.30
(2) 2005	1,495.24	170,795	274,859	5.44	0.80	6.77
(3) 2006	2,189.58	171,676	276,277	7.93	0.84	9.40
(4) 2007	2,309.48	174,827	281,347	8.21	0.89	9.17
(5) 2008	2,320.00	175,715	282,776	8.20	0.95	8.63
(6) Estimated Annual Weighted CT and Meter O&M Expense for the Planning Period (Average of 2006-2008 Values)						\$9.07

MARGINAL DISTRIBUTION COSTS

Table 17. Meter O&M Expense by Customer Class

Customer Class			Weighting Factor	Annual Meter O&M Expense Per Customer (2010 Dollars) (1) x \$9.07 (2)
			(1)	(2)
Residential				
R-01	(1)	Residential	1.00	\$9.07
R-03	(2)	Residential Controlled Demand	1.33	\$12.09
R-91	(3)	Residential Water Heat Controlled	1.00	\$9.07
I-02	(4)	Residential Controlled Dual Fuel	1.00	\$9.07
I-03	(5)	Residential Controlled Service Deffered Load	1.00	\$9.07
I-04	(6)	Residential Fixed Time Of Delivery	1.00	\$9.07
M-42	(7)	Street and Area Lighting	0.00	\$0.00
	(8)	Flood Lighting	0.00	\$0.00
	(9)	Sign Lighting	0.00	\$0.00
	(10)	Energy-Only Street And Area Lighting - Metered	1.00	\$9.07
	(11)	Energy-Only Street And Area Lighting - Non-Metered	0.00	\$0.00
Commercial and Industrial				
G-01	(12)	General Service < 20 kW	1.00	\$9.07
G-01	(13)	General Service >= 20 kW	3.91	\$35.40
F-61	(14)	Farm Service	1.00	\$9.07
C-02	(15)	Large Commercial Service		
		Secondary	46.86	\$424.86
		Primary	46.86	\$424.86
C-03	(16)	Large General Service (Real Time Pricing)	46.86	\$424.86
C-09	(17)	Large General Service (Time Of Use)	46.86	\$424.86
R-91	(18)	Water Heating	1.00	\$9.07
I-01	(19)	Large Controlled Service	7.81	\$70.81
I-02	(20)	Small Controlled Service	2.93	\$26.55
I-03	(21)	Small Controlled Service	2.93	\$26.55
I-04	(22)	Fixed Time Of Delivery Service	1.33	\$12.09
I-06	(23)	Bulk Interruptible Service	46.86	\$424.86
M-03	(24)	Irrigation Service	46.86	\$424.86
M-04	(25)	Commercial Time Of Use	46.86	\$424.86
M-42	(26)	Area, Flood & Sign Lighting	0.00	\$0.00
	(27)	Streetlighting	0.00	\$0.00
	(28)	Other Public Authority	3.91	\$35.40

D. Lighting Operation and Maintenance Expenses

Development of lighting O&M is shown on Table 18. OTP books expenses for both lighting facilities and distribution facilities used by lights in the FERC lighting O&M accounts. We used the average over the period 2006-2008 as the estimate of the marginal level of these expenses.

MARGINAL DISTRIBUTION COSTS

Table 18. Lighting O&M Expense per Light

Year	Total Lighting Operation Maintenance Expenses (‘000 Dollars)	Number of Lights	Lighting Expenses Per Light (Dollars) (1)/(2)*1000	Weighted Labor and Materials Cost Index (2010=1.00)	Lighting Expense Per Light (2010 Dollars) (3)/(4)
	(1)	(2)	(3)	(4)	(5)
(1) 2004	\$924	50,589	18.27	0.7627	23.95
(2) 2005	\$979	50,854	19.26	0.8030	23.98
(3) 2006	\$1,069	50,930	20.99	0.8435	24.88
(4) 2007	\$1,114	51,047	21.83	0.8948	24.40
(5) 2008	\$1,238	51,135	24.20	0.9507	25.46
(6)	Estimated Annual Weighted Lighting O&M Expense for Planning Period (Average of 2006-2008)				\$24.91

OTHER MARGINAL COSTS

VII. OTHER MARGINAL COSTS

A. Customer Accounts Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are the function of a number of customers on the system. As a starting point we reviewed OTP’s FERC Form 1 customer account and service expense levels for the period 2004-2008.

As shown on Table 19, we divided annual customer accounts expenses for 2004-2008 by weighted customers to obtain a customer accounts expense per weighted customer.²⁶ The weights reflect the relative cost responsibility of each class for each sub-account, as measured by the allocation factors, covering ten cost-of-service groups, from OTP’s 2008 class cost of service study. We used the average expense per weighted customer over the entire period as an estimate of marginal expense.

Table 19. Customer Accounts Expense per Weighted Customer

	2004 (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)
(1) Customer Accounts Expenses (Thousand Dollars)	\$7,914.07	\$7,820.39	\$8,366.48	\$9,103.00	\$9,533.40
(2) Number of Customers	170,154	170,795	171,676	174,827	175,715
(3) Weighted Customers (2) x 0.82	139,527	140,052	140,775	143,358	144,086
(4) Expense per Weighted Customer (Dollars) [(1) / (3)] x 1000	\$56.72	\$55.84	\$59.43	\$63.50	\$66.16
(5) Labor Cost Index (2010=1.00)	0.82	0.86	0.89	0.92	0.96
(6) Expense Per Weighted Customer in 2010 Dollars (4) / (5)	\$69.21	\$65.23	\$66.88	\$68.90	\$69.22
(7) Estimated Annual Expense Per Weighted Customer For the Planning Period (2010 Dollars) (Average 2004-2008)	-----	-----	\$67.89	-----	-----

We developed the customer accounts expense for each customer class by multiplying the class weighting factor by the expense per weighted customer.

²⁶ FERC account 902 activity 181 (Meter Reading Expenses/Meter Turn-on) expenses were excluded because connection/reconnection costs are incurred specifically for customers requiring these services and are not part of generic marginal customer costs.

OTHER MARGINAL COSTS

Table 20. Customer Accounts Expense by Customer Class

	Class	Weighting Factor	Annual Customer Accounts Expense Per Customer (2010 Dollars) (1) x \$67.89
		(1)	(2)
(1)	Residential	1.00	\$67.89
(2)	Farm	0.96	65.02
(3)	Small Commercial	1.29	87.56
(4)	Large Commercial	1.44	97.88
(5)	Lighting	0.02	1.09
(6)	Other Public Authority	0.93	62.95
(7)	Water Heating	0.17	11.51
(8)	Deferred Loads	0.18	12.11
(9)	Controlled Loads	0.19	12.69
(10)	Irrigation Service	1.83	124.27

B. Customer Service and Informational Expenses

Customer service and informational expenses, which include the costs of disseminating information to consumers, vary with the number of customers on the system and are, therefore, marginal.²⁷ The same procedure used for customer accounts expenses was followed to generate an estimated annual expense per weighted customer (Table 21) and per customer by class (Table 22), using the class weights developed from OTP’s ECOSS. We used the 2008 value as our estimate of marginal expense.

²⁷ Note that expenses associated with CIP, a program mandated by Minnesota and South Dakota to promote demand side measures, were omitted. These costs are recovered in a separate charge and are not marginal costs that should be used to set base rates. Also, expenses from marketing products and services (account 908, activity 880) were excluded as they are not marginal costs of providing electric service.

OTHER MARGINAL COSTS

Table 21. Customer Informational and Service Expense per Weighted Customer

	2004 (1)	2005 (2)	2006 (3)	2007 (4)	2008 (5)
(1) Customer Service and Informational Expenses (Thousand Dollars)	\$2,433.99	\$2,434.25	\$2,373.64	\$2,457.69	\$2,514.35
(2) Number of Customers	170,154	170,795	171,676	174,827	175,715
(3) Weighted Number of Customers (2) x 0.81	137,825	138,344	139,058	141,610	142,329
(4) Expense Per Weighted Customer (Dollars) [(1) / (3)] x 1000	\$17.66	\$17.60	\$17.07	\$17.36	\$17.67
(5) Labor Cost Index (2010=1.00)	0.82	0.86	0.89	0.92	0.96
(6) Expense Per Weighted Customer in 2010 Dollars (4) / (5)	\$21.55	\$20.56	\$19.21	\$18.83	\$18.48
(7) Estimated Annual Expense Per Weighted Customer For the Planning Period (2010 Dollars) (2008 Value)	-----	-----	\$18.48	-----	-----

Table 22. Customer Informational and Service Expense by Customer Class

Class	Weighting Factor (1)	Annual Customer Service and Informational Expense Per Customer (2010 Dollars) (1) x \$18.48 (2)
(1) Residential	1.00	\$18.48
(2) Farm	0.91	16.90
(3) Small Commercial	0.95	17.51
(4) Large Commercial	23.71	438.26
(5) Lighting	0.01	0.26
(6) Other Public Authority	0.90	16.60
(7) Water Heating	0.01	0.13
(8) Deferred Loads	0.04	0.78
(9) Controlled Loads	0.04	0.71
(10) Irrigation Service	0.95	17.56

OTHER MARGINAL COSTS

C. Administrative and General Expenses

When a utility adds plant and incurs additional O&M expenses, it typically incurs additional overhead costs as well. Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. General plant typically grows with other types of plant. Our marginal cost study includes plant-related A&G, non-plant-related A&G and general plant loaders to capture these elements of marginal cost.

Based on our understanding of OTP's classification of costs in the various FERC accounts for A&G expenses (including social security and unemployment taxes), we divided these expenses into two categories: (1) those associated with other types of expenses and (2) those associated with plant. We excluded accounts not likely to be marginal with respect to other expenses or plant.²⁸

We identified as potentially marginal non-plant related FERC A&G Accounts 408.1 (Social Security and Unemployment Insurance Taxes), 920 (Administrative and General Salaries), 921 (Office Supplies and Expenses), 925 (Injuries and Damages), 926 (Employee Pensions), 929 (Transfers and Credits), and 930.2 (Miscellaneous General Expenses).

We opted to divide our analysis of non-plant-related A&G expenses. For post employment benefits where expenditures fluctuate with financial market conditions, overtime levels, and employee retirements (FERC Account 926), and for Social Security and Unemployment Taxes (FERC Account 408.1) which is always marginal, NERA calculated the average ratio of these expenditures to total O&M expenses (excluding fuel, purchased power, total A&G, and transmission by others) over the period 1982-2008.²⁹ The average ratio during this period was 0.1411 or 14.11%.

NERA plotted the remaining accounts listed above against O&M expenses and found no discernible marginal relationship. Therefore the total non-plant-related A&G loader is equal to the average ratio of non-plant-related A&G expenses (FERC Accounts 926 and 408.1) to O&M expenses over the period 1982-2008, or 14.11%.

For plant-related A&G, we identified two A&G FERC accounts that vary with the amount of plant in service: Maintenance of General Plant (FERC Account 935) and Property Insurance (FERC Account 924). We used a regression analysis of the first account on cumulative net

²⁸ We excluded FERC Accounts 922 Administrative Expenses Transferred (Credit), 923 Outside Services Employed, 927 Franchise Requirements, 928 Regulatory Requirements, 930.1 Institutional and Goodwill Advertising Expenses, and 931 Rents, which we found to be not marginal for OTP.

²⁹ This approach was adopted on account of the shifting, complicated pattern of lags related to personnel actions and over/under-funding of pensions. The year 2007 was excluded from the analysis because of a sharp decline in pension expenses which OTP viewed as irregular due to a significant amount of payroll loading adjustments in that year.

OTHER MARGINAL COSTS

additions to total electric plant, all in constant dollars, for the period 1982 to 2008, yielding a loader of 0.10 percent. For distribution substations, which require property insurance, we added the average property and terrorism insurance rate, \$0.0729 per \$100 or 0.0729 percent.³⁰ The composite loader applicable to distribution substations is 0.17 percent, while 0.10 percent is applicable to all other distribution plant. Both plant and non-plant loaders are shown on Table 23.

D. General Plant

General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. The need for general plant typically increases with each marginal increase in production, transmission and distribution plant. However, since 1996 there has been very little change in OTP's general plant. A regression of cumulative net additions to general plant on cumulative net additions to total plant (less general plant) using data from 1996-2008 generated an insignificant t-statistic for the explanatory coefficient and therefore we set the general plant loader to zero.

Table 23. Administrative and General and General Plant Loaders

	<u>Estimate of Loading Factor</u>
Administrative and General Expenses and Social Security and Unemployment Taxes	
(1) Applicable to Non-Plant-Related Expenses	14.11%
(2) Applicable to Plant-Related Expenses (Distribution Substations)	0.17%
(3) Applicable to Plant-Related Expenses (Other Distribution)	0.10%
(4) General Plant & the Electric Share of Common Plant	0.00%

E. Marginal Losses

The marginal loss calculations in this study are based on variable and total losses at time of system peak at each voltage level for which costs are calculated. Marginal capacity losses applied to distribution substation and trunkline feeder costs reflect the fact that, to accommodate a kW of additional peak load at the customer's meter, facilities must be expanded by successively more than a kW as you move up the distribution system to

³⁰ Information provided by OTP's Insurance Risk department on 12/2/2009.

OTHER MARGINAL COSTS

accommodate the fixed and variable losses on the system in the peak hour. Peak capacity loss factors were developed from OTP's current loss study.³¹ Marginal energy losses reflect the additional losses incurred to move an added kWh through the system at a particular level of system load. Fixed losses are, by definition, not affected by the increments of load to a fixed system. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated hourly losses by means of an approximation of quadratic losses based on variable losses at system peak load (from OTP's loss studies) and the year 2008 hourly control area loads. The marginal energy losses on OTP's high voltage transmission system through each system component to meters at each voltage level of service were applied to the hourly market price estimates and hourly marginal transmission costs.

³¹ Provided by OTP, 01/28/2010.

COMPUTATION OF ECONOMIC CARRYING CHARGES

VIII. COMPUTATION OF ECONOMIC CARRYING CHARGES

Section V. above describes the development of estimates of marginal investment in several categories of distribution plant. To be useful in ratemaking and other marginal cost applications, the investment must be converted into annual costs using an economic carrying charge. The annual charge reflects the elements of OTP’s revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and taxes. For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year’s charge represents the cost in today’s dollars of owning the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

Key inputs for the economic carrying charge calculation include: (1) the utility’s incremental cost of capital (mix of debt and equity and their respective long-term market costs), (2) the expected inflation rate for that type of plant, net of technical progress, and (3) the average service life and patterns of failure (“Iowa curve”) for that type of plant.

OTP foresees financing of incremental investment through sales of common stock and debt over the study period, as illustrated below.

	Share %	Cost %
Common Stock	50.00	10.50
Debt	50.00	7.50

Another integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. We used 3.0 percent as an approximation of the rate of future inflation net of technical progress, based on OTP’s use of 3.0 percent in their 10-year financial model.

Finally, an adjustment is required for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. The pattern of expected required replacement for each type of plant is defined by an Iowa Curve. An adjustment for this dispersed pattern of replacements using Iowa Curves was included in the derivation of the economic carrying charges. The results of these economic carrying charge calculations are presented below. The adjustments for dispersed retirements are shown on line (2) of this table.

COMPUTATION OF ECONOMIC CARRYING CHARGES

Table 24. Economic Carrying Charges

	Distribution Substation <u>(1)</u>	Distribution Facilities <u>(2)</u>	Meters <u>(3)</u>
(1) Present Value of Revenue Requirements Related to Incremental \$1,000 Investment	\$1,437.44	\$1,463.40	\$1,446.94
(2) Present Value Cost of Replacing Dispersed Retirements Related to Incremental \$1,000 Investment	\$104.36	\$27.95	\$68.40
(3) Total Present Value Cost Related to Incremental \$1,000 Investment (1)+(2)	\$1,541.80	\$1,491.35	\$1,515.34
(4) First-Year Annual Economic Charge Related to Incremental \$1,000 Investment	\$90.57	\$78.06	\$91.51
(5) First-Year Annual Economic Charge Related to Incremental Investment [(4)/\$1,000]	9.06%	7.81%	9.15%

COMPUTATION OF ANNUAL MARGINAL COSTS

IX. COMPUTATION OF ANNUAL MARGINAL COSTS

To compute marginal investment for each distribution component of service to annual marginal costs, we adjusted upwards the investment per unit by the general plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage plus the plant-related A&G loading factor to yield the annualized plant costs. To these costs we added the associated O&M and A&G expenses and the revenue requirements for working capital.

The computation of working capital includes components for cash, materials, supplies and prepayments. The working capital needs were estimated based on recent historical amounts. The revenue requirement for this working capital was developed from OTP's weighted average cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable.

Table 25 shows the derivation of the annual distribution substation and trunkline feeder costs, and Table 26 shows those annual costs adjusted for losses and time-differentiated, using estimates of the relative probability of distribution substation peaks.

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 25. Derivation of Annual Distribution Substation and Trunkline Feeder Costs

	2010 Dollars per kW
(1) Marginal Investment per kW	\$92.22
(2) With General Plant Loading (1) x 1.0000	92.22
(3) Annual Economic Carrying Charge Related to Capital Investment	9.06%
(4) A&G Loading (plant related)	0.17%
(5) Total Annual Carrying Charge (3) + (4)	9.23%
(6) Annualized Costs (2) x (5)	8.51
(7) O&M Expenses	2.87
(8) With A&G Loading (7) x 1.1411 (Non-plant Related)	3.27
(9) Subtotal (6) + (8)	11.78
Working Capital	
(10) Material and Supplies (2) x 1.24%	1.14
(11) Prepayments (2) x 0.13%	0.12
(12) Cash Working Capital Allowance (8) x 5.84%	0.19
(13) Total Working Capital (10) + (11) + (12)	1.45
(14) Revenue Requirement for Working Capital (13) x 12.49%	0.18
(15) Total Distribution Substation Costs (9) + (14)	\$11.96

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 26. Time-Differentiated Distribution Substation and Trunkline Feeder Costs by Voltage Level and Period

	<u>Annual Cost</u>		Period Assignment Factor (Percent)	<u>Seasonal Cost</u>	
	<u>Secondary</u>	<u>Primary</u>		<u>Secondary</u>	<u>Primary</u>
	(2010 Dollars per KW)	(2010 Dollars per KW)		(2010 Dollars per KW)	(2010 Dollars per KW)
	(1)	(2)	(3)	(1) x (3) (4)	(2) x (3) (5)
(1) Summer Peak Period	12.89	12.53	37%	4.74	4.61
(2) Summer Shoulder	12.89	12.53	25%	3.29	3.19
(3) Summer Off-Peak Period	12.89	12.53	0%	0.04	0.04
(4) Winter Peak Period	12.89	12.53	14%	1.84	1.79
(5) Winter Shoulder	12.89	12.53	5%	0.70	0.68
(6) Winter Off-Period	12.89	12.53	18%	2.29	2.22

Tables 27 below show the development of the annual marginal cost for local distribution facilities, and lighting. Tables 28 show the annualization of meters and service drops and also include customer-related expenses.

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 27 (I). Derivation of Annual Distribution Facilities Costs

	Residential				
	Single Family Urban	Single Family Rural	Apartment Gas	Apartment Electric	Farm
	----- (2010 Dollars per kW) -----				
	(1)	(2)	(3)	(4)	(5)
(1) Marginal Investment per kW	\$147.76	\$268.13	\$126.61	\$73.86	\$296.89
(2) With General Plant Loading (1) x 1.0000	147.76	268.13	126.61	73.86	296.89
(3) Annual Economic Carrying Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%	7.81%
(4) A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%	0.10%
(5) Total Annual Carrying Charge (3) + (4)	7.90%	7.90%	7.90%	7.90%	7.90%
(6) Annualized Costs (2) x (5)	11.68	21.19	10.00	5.84	23.46
(7) O&M Expense per kW	3.70	3.70	3.70	3.70	3.70
(8) With A&G Loading (7) x 1.1411 (non-plant related)	4.22	4.22	4.22	4.22	4.22
(9) Distribution Facilities Related Costs (6) + (8)	15.89	25.40	14.22	10.05	27.68
Working Capital					
(10) Material and Supplies (2) x 1.24%	1.83	3.32	1.57	0.92	3.68
(11) Prepayments (2) x 0.13%	0.19	0.35	0.16	0.10	0.39
(12) Cash Working Capital Allowance (8) x 5.84%	0.25	0.25	0.25	0.25	0.25
(13) Total Working Capital (10) + (11) + (12)	2.27	3.92	1.98	1.26	4.31
(14) Revenue Requirement for Working Capital (13) x 12.49%	0.28	0.49	0.25	0.16	0.54
(15) Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	\$16.18	\$25.89	\$14.47	\$10.21	\$28.22

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 27 (II). Derivation of Annual Distribution Facilities Costs

	Small Commercial				
	Stand-Alone customer, overhead	Stand-Alone customer 3ph, overhead	Shared- customer 3ph, overhead	Stand-Alone customer, underground	Shared- customer 3ph, underground
	(1)	(2)	(3)	(4)	(5)
	----- (2010 Dollars per kW) -----				
(1) Marginal Investment per kW	\$37.90	\$60.30	\$69.04	\$111.21	\$179.44
(2) With General Plant Loading (1) x 1.0000	37.90	60.30	69.04	111.21	179.44
(3) Annual Economic Carrying Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%	7.81%
(4) A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%	0.10%
(5) Total Annual Carrying Charge (3) + (4)	7.90%	7.90%	7.90%	7.90%	7.90%
(6) Annualized Costs (2) x (5)	2.99	4.76	5.46	8.79	14.18
(7) O&M Expense per kW	3.70	3.70	3.70	3.70	3.70
(8) With A&G Loading (7) x 1.1411 (non-plant related)	4.22	4.22	4.22	4.22	4.22
(9) Distribution Facilities Related Costs (6) + (8)	7.21	8.98	9.67	13.00	18.40
Working Capital					
(10) Material and Supplies (2) x 1.24%	0.47	0.75	0.86	1.38	2.23
(11) Prepayments (2) x 0.13%	0.05	0.08	0.09	0.14	0.23
(12) Cash Working Capital Allowance (8) x 5.84%	0.25	0.25	0.25	0.25	0.25
(13) Total Working Capital (10) + (11) + (12)	0.77	1.07	1.19	1.77	2.70
(14) Revenue Requirement for Working Capital (13) x 12.49%	0.10	0.13	0.15	0.22	0.34
(15) Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	\$7.31	\$9.12	\$9.82	\$13.23	\$18.73

Table 27 (III). Derivation of Annual Distribution Facilities Costs

	Large Commercial (Secondary)				Very Large Commercial (Secondary TOU)	Large Commercial (Primary)	
	101-150kVa, 3ph	151-300kVa, 3ph	301-500kVa, 3ph	>501 kVa, 3ph	3000 kVa (LGS TOU), 3ph	3000 kVa (LGS), 3ph	5000 kVa (LGS TOU), 3ph
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
	----- (2010 Dollars per kW) -----						
(1) Marginal Investment per kW	\$94.74	\$54.14	\$45.84	\$24.45	\$25.91	\$7.18	\$4.55
(2) With General Plant Loading (1) x 1.0000	94.74	54.14	45.84	24.45	25.91	7.18	4.55
(3) Annual Economic Carrying Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
(4) A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5) Total Annual Carrying Charge (3) + (4)	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
(6) Annualized Costs (2) x (5)	7.49	4.28	3.62	1.93	2.05	0.57	0.36
(7) O&M Expense per kW	3.70	3.70	3.70	3.70	3.70	2.24	2.24
(8) With A&G Loading (7) x 1.1411 (non-plant related)	4.22	4.22	4.22	4.22	4.22	2.56	2.56
(9) Distribution Facilities Related Costs (6) + (8)	11.70	8.50	7.84	6.15	6.26	3.13	2.92
Working Capital							
(10) Material and Supplies (2) x 1.24%	1.17	0.67	0.57	0.30	0.32	0.09	0.06
(11) Prepayments (2) x 0.13%	0.12	0.07	0.06	0.03	0.03	0.01	0.01
(12) Cash Working Capital Allowance (8) x 5.84%	0.25	0.25	0.25	0.25	0.25	0.15	0.15
(13) Total Working Capital (10) + (11) + (12)	1.54	0.99	0.87	0.58	0.60	0.25	0.21
(14) Revenue Requirement for Working Capital (13) x 12.49%	0.19	0.12	0.11	0.07	0.08	0.03	0.03
(15) Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	\$11.90	\$8.62	\$7.95	\$6.22	\$6.34	\$3.16	\$2.94

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 28. Derivation of Annual Lighting Costs, including Distribution Facilities for Lights

	Lighting			
	Area Light 1 HPS 9 (no pole), underground	Area Light 1 HPS 9 (no pole), overhead	Street Light - (no light, no pole), underground	Street Light - (no light, no pole), overhead
	----- (2010 Dollars per fixture) -----			
	(1)	(2)	(3)	(4)
(1) Marginal Investment per fixture	\$1,387.15	\$1,248.71	\$767.08	\$634.44
(2) With General Plant Loading (1) x 1.0000	1,387.15	1,248.71	767.08	634.44
(3) Annual Economic Carrying Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%
(4) A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%
(5) Total Annual Carrying Charge (3) + (4)	7.90%	7.90%	7.90%	7.90%
(6) Annualized Costs (2) x (5)	109.61	98.67	60.61	50.13
(7) Lighting O&M Expenses	24.91	24.91	24.91	24.91
(8) With A&G Loading (7) x 1.1411 (non-plant related)	28.43	28.43	28.43	28.43
(9) Distribution Facilities Related Costs (6) + (8)	138.04	127.10	89.04	78.56
Working Capital				
(10) Material and Supplies (2) x 1.24%	17.20	15.48	9.51	7.87
(11) Prepayments (2) x 0.13%	1.80	1.62	1.00	0.82
(12) Cash Working Capital Allowance (8) x 5.84%	1.66	1.66	1.66	1.66
(13) Total Working Capital (10) + (11) + (12)	20.66	18.77	12.17	10.35
(14) Revenue Requirement for Working Capital (13) x 12.49%	2.58	2.34	1.52	1.29
(15) Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	\$140.62	\$129.44	\$90.56	\$79.85

Tables 29 annualize the meter and service costs and add associated O&M and customer care expenses.

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 29 (I). Derivation of Annual Meter, Service and Customer-Related Costs

	Residential	Residential Controlled Demand	Residential Water Heat Controlled	Residential Controlled Dual Fuel	Residential Controlled Deferred Load	Residential Fixed Time Of Delivery	Area, Flood & Sign Lighting
	(2010 Dollars per Customer)						
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
a) Investment - Meter Costs							
(1) Meter Cost Investment per Customer	\$77.02	\$375.00	\$257.01	\$253.65	\$343.91	\$343.91	\$0.00
(2) With General Plant Loading (1) x 1.0000	77.02	375.00	257.01	253.65	343.91	343.91	0.00
(3) Annual Economic Charge Related to Capital Investment	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%
(4) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5) Total Carrying Charge Meters (3) + (4)	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%
(6) Total Annualized Meter Costs (2) x (5)	7.12	34.67	23.76	23.45	31.80	31.80	0.00
b) Investment - Meter Service Drops							
(7) Service Cost Investment per Customer	\$370.52	\$370.52	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
(8) With General Plant Loading (1) x 1.0000	370.52	370.52	0.00	0.00	0.00	0.00	0.00
(9) Annual Economic Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
(10) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(11) Total Carrying Charge Services (9) + (10)	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
(12) Total Annualized Service Costs (8) x (11)	29.28	29.28	0.00	0.00	0.00	0.00	0.00
c) O&M - Meter, Customer Accounts Expenses, Customer Service							
(13) Meter and CT O&M Expenses	9.07	12.09	9.07	9.07	9.07	9.07	0.00
(14) Customer Accounts Expenses	67.89	79.40	11.51	12.69	12.11	12.11	1.09
(15) Customer Service and Informational Expenses	18.48	18.61	0.13	0.71	0.78	0.78	0.26
(16) With A&G Loading [(13)+(14)+(15)] x 1.1411 (Non-plant Related)	108.91	125.64	23.63	25.64	25.06	25.06	1.54
(17) Customer-Related Costs (6) + (12) + (16)	145.31	189.59	47.40	49.09	56.86	56.86	1.54
Working Capital							
(18) Materials and Supplies (2) x 1.24%	0.96	4.65	3.19	3.15	4.26	4.26	0.00
(19) Prepayments (2) x 0.130%	0.10	0.49	0.33	0.33	0.45	0.45	0.00
(20) Cash Working Capital (16) x 5.84%	6.36	7.34	1.38	1.50	1.46	1.46	0.09
(21) Revenue Requirement for Working Capital [(18)+(19)+(20)] x 12.49%	0.93	1.56	0.61	0.62	0.77	0.77	0.01
(22) Total Annual Marginal Customer-Related Costs (11) + (15)	\$146.23	\$191.15	\$48.01	\$49.72	\$57.63	\$57.63	\$1.55

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 29 (II). Derivation of Annual Meter, Service and Customer-Related Costs

	General Service < 20 kW	General Service ≥ 20 kW	Farm Service	Large Commercial Secondary	Large Commercial Primary
	----- (2010 Dollars per Customer) -----				
	(1)	(2)	(3)	(4)	(5)
a) Investment - Meter Costs					
(1) Meter Cost Investment per Customer	\$332.82	\$332.82	\$343.91	\$1,238.58	\$6,794.56
(2) With General Plant Loading (1) x 1.0000	332.82	332.82	343.91	1,238.58	6,794.56
(3) Annual Economic Charge Related to Capital Investment	9.15%	9.15%	9.15%	9.15%	9.15%
(4) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%
(5) Total Carrying Charge Meters (3) + (4)	9.25%	9.25%	9.25%	9.25%	9.25%
(6) Total Annualized Meter Costs (2) x (5)	30.77	30.77	31.80	114.53	628.26
b) Investment - Meter Service Drops					
(7) Service Cost Investment per Customer	\$522.28	\$522.28	\$403.34	\$22,198.26	\$22,862.22
(8) With General Plant Loading (1) x 1.0000	522.28	522.28	403.34	22,198.26	22,862.22
(9) Annual Economic Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%	7.81%
(10) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%
(11) Total Carrying Charge Services (9) + (10)	7.90%	7.90%	7.90%	7.90%	7.90%
(12) Total Annualized Service Costs (8) x (11)	41.27	41.27	31.87	1,754.11	1,806.58
c) O&M - Meter, Customer Accounts Expenses, Customer Service					
(13) Meter and CT O&M Expenses	9.07	35.40	9.07	424.86	424.86
(14) Customer Accounts Expenses	87.56	87.56	65.02	97.88	97.88
(15) Customer Service and Informational Expenses	17.51	17.51	16.90	438.26	438.26
(16) With A&G Loading [(13)+(14)+(15)] x 1.1411 (Non-plant Related)	130.25	160.29	103.83	1,096.60	1,096.60
(17) Customer-Related Costs (6) + (12) + (16) Working Capital	202.29	232.34	167.50	2,965.23	3,531.43
(18) Materials and Supplies (2) x 1.24%	4.13	4.13	4.26	15.36	84.25
(19) Prepayments (2) x 0.130%	0.43	0.43	0.45	1.61	8.83
(20) Cash Working Capital (16) x 5.84%	7.61	9.36	6.06	64.04	64.04
(21) Revenue Requirement for Working Capital [(18)+(19)+(20)] x 12.49%	1.52	1.74	1.35	0.00	19.63
(22) Total Annual Marginal Customer-Related Costs (11) + (15)	\$203.81	\$234.07	\$168.85	\$2,965.23	\$3,551.06

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 29 (III). Derivation of Annual Meter, Service and Customer-Related Costs

	Large GS (Real Time Pricing) Secondary	Large GS (Real Time Pricing) Primary	Large GS (TOU) Secondary	Large GS (TOU) Primary
	(2010 Dollars per Customer)			
	(1)	(2)	(3)	(4)
a) Investment - Meter Costs				
(1) Meter Cost Investment per Customer	\$1,238.58	\$6,794.56	\$1,238.58	\$6,794.56
(2) With General Plant Loading (1) x 1.0000	1,238.58	6,794.56	1,238.58	6,794.56
(3) Annual Economic Charge Related to Capital Investment	9.15%	9.15%	9.15%	9.15%
(4) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%
(5) Total Carrying Charge Meters (3) + (4)	9.25%	9.25%	9.25%	9.25%
(6) Total Annualized Meter Costs (2) x (5)	114.53	628.26	114.53	628.26
b) Investment - Meter Service Drops				
(7) Service Cost Investment per Customer	\$22,198.26	\$22,862.22	\$22,198.26	\$22,862.22
(8) With General Plant Loading (1) x 1.0000	22,198.26	22,862.22	22,198.26	22,862.22
(9) Annual Economic Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%
(10) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%
(11) Total Carrying Charge Services (9) + (10)	7.90%	7.90%	7.90%	7.90%
(12) Total Annualized Service Costs (8) x (11)	1,754.11	1,806.58	1,754.11	1,806.58
c) O&M - Meter, Customer Accounts Expenses, Customer Service				
(13) Meter and CT O&M Expenses	424.86	424.86	424.86	424.86
(14) Customer Accounts Expenses	97.88	97.88	97.88	97.88
(15) Customer Service and Informational Expenses	438.26	438.26	438.26	438.26
(16) With A&G Loading [(13)+(14)+(15)] x 1.1411 (Non-plant Related)	1,096.60	1,096.60	1,096.60	1,096.60
(17) Customer-Related Costs (6) + (12) + (16)	2,965.23	3,531.43	2,965.23	3,531.43
Working Capital				
(18) Materials and Supplies (2) x 1.24%	15.36	84.25	15.36	84.25
(19) Prepayments (2) x 0.130%	1.61	8.83	1.61	8.83
(20) Cash Working Capital (16) x 5.84%	64.04	64.04	64.04	64.04
(21) Revenue Requirement for Working Capital [(18)+(19)+(20)] x 12.49%	10.12	19.63	10.12	19.63
(22) Total Annual Marginal Customer-Related Costs (11) + (15)	\$2,975.35	\$3,551.06	\$2,975.35	\$3,551.06

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 29 (IV). Derivation of Annual Meter, Service and Customer-Related Costs

	Commercial Water Heat Controlled	Large Com. Controlled Dual Fuel (I-01)	Small Com. Controlled Dual Fuel (I-02)	Small Com. Controlled Deferred Load (I-03)	Small Com.Fixed Time of Delivery (I-04)	Bulk Interruptible	Irrigation
	(1)	(4)	(2)	(3)	(5)	(6)	(7)
a) Investment - Meter Costs							
(1) Meter Cost Investment per Customer	\$257.01	\$1,521.57	\$253.65	\$340.95	\$340.95	\$6,794.56	\$935.53
(2) With General Plant Loading (1) x 1.0000	257.01	1,521.57	253.65	340.95	340.95	6,794.56	935.53
(3) Annual Economic Charge Related to Capital Investment	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%	9.15%
(4) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5) Total Carrying Charge Meters (3) + (4)	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%	9.25%
(6) Total Annualized Meter Costs (2) x (5)	23.76	140.69	23.45	31.53	31.53	628.26	86.50
b) Investment - Meter Service Drops							
(7) Service Cost Investment per Customer	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00	\$22,862.22	\$370.52
(8) With General Plant Loading (1) x 1.0000	0.00	0.00	0.00	0.00	0.00	22,862.22	370.52
(9) Annual Economic Charge Related to Capital Investment	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%	7.81%
(10) A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(11) Total Carrying Charge Services (9) + (10)	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%	7.90%
(12) Total Annualized Service Costs (8) x (11)	0.00	0.00	0.00	0.00	0.00	1,806.58	29.28
c) O&M - Meter, Customer Accounts Expenses, Customer Service							
(13) Meter and CT O&M Expenses	9.07	70.81	26.55	26.55	12.09	424.86	424.86
(14) Customer Accounts Expenses	11.51	12.69	12.69	12.69	12.69	110.57	124.27
(15) Customer Service and Informational Expenses	0.13	0.71	0.71	0.71	0.71	438.97	17.56
(16) With A&G Loading [(13)+(14)+(15)] x 1.1411 (Non-plant Related)	23.63	96.09	45.59	45.59	29.09	1,111.89	646.65
(17) Customer-Related Costs (6) + (12) + (16)	47.40	236.78	69.04	77.11	60.61	3,546.72	762.43
Working Capital							
(18) Materials and Supplies (2) x 1.24%	3.19	18.87	3.15	4.23	4.23	84.25	11.60
(19) Prepayments (2) x 0.130%	0.33	1.98	0.33	0.44	0.44	8.83	1.22
(20) Cash Working Capital (16) x 5.84%	1.38	5.61	2.66	2.66	1.70	64.93	37.76
(21) Revenue Requirement for Working Capital [(18)+(19)+(20)] x 12.49%	0.61	3.30	0.77	0.92	0.80	19.74	6.32
(22) Total Annual Marginal Customer-Related Costs (11) + (15)	\$48.01	\$240.09	\$69.81	\$78.03	\$61.41	\$3,566.46	\$768.75

COMPUTATION OF ANNUAL MARGINAL COSTS

Table 29 (V). Derivation of Annual Meter, Service and Customer-Related Costs

	Commercial TOU	Energy-Only Street & Area Lighting - Metered	Street & Area, Flood and Sign Lighting	Other Public Authority
	(2010 Dollars per Customer)			
<u>a) Investment - Meter Costs</u>	(1)	(3)	(4)	(5)
(1) Meter Cost Investment per Customer	\$1,139.23	\$77.02		\$299.89
(2) With General Plant Loading (1) x 1.0000	1,139.23	77.02		299.89
(3) Annual Economic Charge Related to Capital Investment	9.15%	9.15%		9.15%
(4) A&G Loading (Plant Related)	0.10%	0.10%		0.10%
(5) Total Carrying Charge Meters (3) + (4)	9.25%	9.25%		9.25%
(6) Total Annualized Meter Costs (2) x (5)	105.34	7.12		27.73
<u>b) Investment - Meter Service Drops</u>				
(7) Service Cost Investment per Customer	\$22,862.22	\$0.00		\$1,692.69
(8) With General Plant Loading (1) x 1.0000	22,862.22	0.00		1,692.69
(9) Annual Economic Charge Related to Capital Investment	7.81%	7.81%		7.81%
(10) A&G Loading (Plant Related)	0.10%	0.10%		0.10%
(11) Total Carrying Charge Services (9) + (10)	7.90%	7.90%		7.90%
(12) Total Annualized Service Costs (8) x (11)	1,806.58	0.00		133.76
<u>c) O&M - Meter, Customer Accounts Expenses, Customer Service</u>				
(13) Meter and CT O&M Expenses	424.86	0.00	0.00	35.40
(14) Customer Accounts Expenses	97.88	1.09	1.09	62.95
(15) Customer Service and Informational Expenses	438.26	0.26	0.26	16.60
(16) With A&G Loading [(13)+(14)+(15)] x 1.1411 (Non-plant Related)	1,096.60	1.54	1.54	131.17
(17) Customer-Related Costs (6) + (12) + (16)	3,008.51	8.66	1.54	292.66
<u>Working Capital</u>				
(18) Materials and Supplies (2) x 1.24%	14.13	0.96	0.00	3.72
(19) Prepayments (2) x 0.130%	1.48	0.10	0.00	0.39
(20) Cash Working Capital (16) x 5.84%	64.04	0.09	0.09	7.66
(21) Revenue Requirement for Working Capital [(18)+(19)+(20)] x 12.49%	9.95	0.14	0.01	1.47
(22) Total Annual Marginal Customer-Related Costs (11) + (15)	\$3,018.46	\$8.81	\$1.55	\$294.13

2010 SUMMARY TABLES

X. 2010 SUMMARY TABLES

Marginal energy costs, as well as generation capacity, transmission and distribution substation costs, were estimated on an hourly basis, which means they can be expressed in terms of cost per kWh. This section shows all the 2010 time-differentiated costs (including energy) on a per-kWh basis, averaged over the hours in the period. Capacity costs are often expressed on a per-kW basis. Converting hourly marginal costs per kW to period costs per kW requires making an assumption about how consumers' consumption changes throughout a costing period when their peak demand in that period changes. For purposes of these summary tables, we summed the hourly capacity costs within each period. This is consistent with the assumption that a customer who used an additional kW at the time of his peak within a costing period also uses an additional kW in all other hours of that period. Finally, we summarized the time-varying marginal costs with generation capacity, transmission and distribution substation costs stated on a per-kW basis, and marginal energy costs on a per-kWh basis.

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Table 30. 2010 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	7.2700	4.8799	1.1997	6.2603	4.2830	2.7257
Generation Capacity	0.8554	0.0803	0.0014	0.1833	0.0424	0.0032
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Transmission	5.3321	0.6685	0.0174	3.7484	0.6874	0.1625
Distribution Substation	0.9063	0.3090	0.0032	0.1177	0.0468	0.0823
Total	16.1947	7.7687	3.0526	12.1407	6.8905	4.8046
Seasonal	7.1118			7.3035		
Annual	7.2394					
(2) Primary						
Energy	6.9976	4.7111	1.1650	5.9826	4.1064	2.6193
Generation Capacity	0.8181	0.0768	0.0014	0.1740	0.0401	0.0030
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Transmission	5.1086	0.6399	0.0167	3.5601	0.6501	0.1533
Distribution Substation	0.8813	0.3005	0.0031	0.1145	0.0455	0.0800
Total	15.5954	7.5180	2.9759	11.6210	6.6318	4.6453
Seasonal	6.8786			7.0223		
Annual	6.9742					
(3) Transmission						
Energy	6.5637	4.4402	1.1084	5.5492	3.8284	2.4509
Generation Capacity	0.7597	0.0713	0.0013	0.1597	0.0366	0.0027
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Transmission	4.7567	0.5948	0.0155	3.2707	0.5933	0.1393
Distribution Substation						
Total	13.7971	6.8233	2.8422	10.6966	6.1753	4.3099
Seasonal	6.2440			6.4981		
Annual	6.4132					
Note: ¹	Operating reserve includes both spinning and supplemental reserve.					

2010 SUMMARY TABLES

Table 31. 2010 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$1.12	\$0.21	\$0.00	\$0.36	\$0.08	\$0.01
Transmission	\$6.97	\$1.78	\$0.06	\$7.32	\$1.28	\$0.56
Distribution Substation	\$1.18	\$0.82	\$0.01	\$0.23	\$0.09	\$0.29
Total	\$9.27	\$2.81	\$0.07	\$7.91	\$1.45	\$0.86
Seasonal	\$12.16			\$10.22		
Annual	\$10.86					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.2700	4.8799	1.1997	6.2603	4.2830	2.7257
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Total	9.1010	6.7108	3.0306	8.0913	6.1139	4.5566
Seasonal	5.4509			5.9020		
Annual	5.7512					
(2) Primary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$1.07	\$0.20	\$0.00	\$0.34	\$0.07	\$0.01
Transmission	\$6.68	\$1.70	\$0.06	\$6.95	\$1.21	\$0.53
Distribution Substation	\$1.15	\$0.80	\$0.01	\$0.22	\$0.08	\$0.28
Total	\$8.90	\$2.70	\$0.07	\$7.52	\$1.37	\$0.82
Seasonal	\$11.67			\$9.71		
Annual	\$10.36					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	6.9976	4.7111	1.1650	5.9826	4.1064	2.6193
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Total	8.7874	6.5009	2.9547	7.7724	5.8961	4.4090
Seasonal	5.2839			5.6906		
Annual	5.5546					
(3) Transmission						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$0.99	\$0.19	\$0.00	\$0.31	\$0.07	\$0.01
Transmission	\$6.22	\$1.58	\$0.05	\$6.39	\$1.11	\$0.48
Distribution Substation						
Total	\$7.21	\$1.77	\$0.06	\$6.70	\$1.18	\$0.49
Seasonal	\$9.04			\$8.37		
Annual	\$8.59					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	6.5637	4.4402	1.1084	5.5492	3.8284	2.4509
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Total	8.2807	6.1572	2.8254	7.2662	5.5454	4.1679
Seasonal	5.0093			5.3504		
Annual	5.2364					

Note: ¹ Operating reserve includes both spinning and supplemental reserve.

2010 SUMMARY TABLES

Table 32 summarizes monthly marginal local distribution facilities costs per kW of design demand and on a per customer basis, by class.

Table 32: 2010 Summary of Monthly Marginal Local Distribution Facilities (and Lighting) Costs per kW of Design Demand and Per Customer or per Fixture

Customer Class		Monthly Facility Cost per kW of Design Demand (\$/kW)	Estimate of Typical Design Demand by Customer kW	Monthly Facility Cost per Customer (\$/customer/mo.) (1)*(2) (3)
		(1)	(2)	(3)
Residential				
(1)	Urban	\$1.35	8	\$11.23
(2)	Rural	2.16	21	44.70
(3)	Apartment, Gas	1.21	5	5.48
(4)	Apartment, Electric	0.85	9	7.73
(5)	Farm	2.35	21	48.71
Small Commercial				
(6)	Stand-Alone customer, overhead	0.61	50	30.44
(7)	Stand-Alone customer 3ph, overhead	0.76	75	56.97
(8)	Shared-customer 3ph, overhead	0.82	75	61.38
(9)	Stand-Alone customer, underground	1.10	50	55.11
(10)	Shared-customer 3ph, underground	1.56	75	117.09
Large Commercial (Secondary Only)				
(11)	101-150kVa, 3ph	0.99	150	148.70
(12)	151-300kVa, 3ph	0.72	300	215.46
(13)	301-500kVa, 3ph	0.66	500	331.19
(14)	>501 kVa, 3ph	0.52	2,600	1,347.99
(15)	Very Large Commercial (Secondary TOU) 3000 kVa (LGS)	0.53	3,000	1,584.89
Large Commercial (Primary)				
(16)	3000 kVa (LGS)	0.26	3,000	789.34
(17)	5000 kVa (LGS TOU)	0.25	5,000	1,227.04
Lighting				<u>\$/Fixture</u>
(18)	Area Light 1 HPS 9 (no pole), underground			11.72
(19)	Area Light 1 HPS 9 (no pole), overhead			10.79
(20)	Street Light - (no light, no pole), underground			7.55
(21)	Street Light - (no light, no pole), overhead			6.65

Table 33 summarizes the monthly marginal customer cost by customer class.

2010 SUMMARY TABLES

Table 33. 2010 Summary of Monthly Marginal Customer Costs

		Monthly Marginal Customer Cost per Customer (2010\$ /mo.)
Residential		
R-01	Residential	\$12.19
R-03	Residential Controlled Demand	15.93
R-91	Residential Water Heat Controlled	4.00
I-02	Residential Controlled Dual Fuel	4.14
I-03	Residential Controlled Deferred Load	4.80
I-04	Residential Fixed Time Of Delivery	4.80
M-42	Street Lighting	0.13
	Flood Lighting	0.13
	Sign Lighting	0.13
	Energy-Only Street & Area Lighting - Metered	0.73
	Energy-Only Street & Area Lighting - Non-Metered	0.13
Commercial and Industrial		
G-01	General Service < 20 kW	16.98
G-01	General Service >= 20 kW	19.51
F-61	Farm Service	14.07
C-02	Large Commercial Service	
	Secondary	247.10
	Primary	295.92
C-03	Large General Service (Real Time Pricing)	
	Secondary	247.95
	Primary	295.92
C-09	Large General Service (Time Of Use)	
	Secondary	247.95
	Primary	295.92
R-91	Commercial Water Heat Controlled	4.00
I-01	Large Commercial Controlled Dual Fuel	20.01
I-02	Small Commercial Controlled Dual Fuel	5.82
I-03	Small Commercial Controlled Deferred Load	6.50
I-04	Small Commercial Fixed Time Of Delivery	5.12
I-06	Bulk Interruptible	297.20
M-03	Irrigation Service	64.06
M-04	Commercial Time Of Use	251.54
	Street Lighting	0.13
	Flood Lighting	0.13
	Sign & Area Lighting	0.13
	Energy-Only Street & Area Lighting - Metered	0.73
	Energy-Only Street & Area Lighting - Non-Metered	0.13
Miscellaneous		
	Streetlighting	0.13
	Other Public Authority	24.51

APPENDIX

APPENDIX

Marginal Generation and Transmission Costs, 2011 – 2014

Table 34. 2011 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	7.6539	5.1782	1.4189	6.6333	4.6213	2.9212
Generation Capacity	1.1645	0.1093	0.0019	0.3143	0.0727	0.0055
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Transmission	5.5454	0.6953	0.0181	3.8983	0.7149	0.1690
Distribution Substation	0.9063	0.3090	0.0032	0.1177	0.0468	0.0823
Total	17.1009	8.1227	3.2731	12.7946	7.2866	5.0090
Seasonal	7.5032			7.6774		
Annual	7.6192					
(2) Primary						
Energy	7.3671	4.9990	1.3779	6.3397	4.4309	2.8082
Generation Capacity	1.1138	0.1046	0.0019	0.2983	0.0688	0.0052
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Transmission	5.3129	0.6655	0.0173	3.7025	0.6761	0.1594
Distribution Substation	0.8813	0.3005	0.0031	0.1145	0.0455	0.0800
Total	16.4649	7.8592	3.1900	12.2447	7.0110	4.8425
Seasonal	7.2559			7.3803		
Annual	7.3387					
(3) Transmission						
Energy	6.9104	4.7113	1.3112	5.8811	4.1311	2.6292
Generation Capacity	1.0342	0.0971	0.0017	0.2738	0.0628	0.0047
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Transmission	4.9470	0.6186	0.0161	3.4015	0.6170	0.1449
Distribution Substation						
Total	14.6087	7.1440	3.0460	11.2734	6.5279	4.4957
Seasonal	6.5987			6.8313		
Annual	6.7536					

Note: ¹ Operating reserve includes both spinning and supplemental reserve.

Table 35. 2011 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$1.52	\$0.29	\$0.01	\$0.61	\$0.14	\$0.02
Transmission	\$7.25	\$1.85	\$0.06	\$7.61	\$1.33	\$0.59
Distribution Substation	\$1.18	\$0.82	\$0.01	\$0.23	\$0.09	\$0.29
Total	\$9.96	\$2.96	\$0.08	\$8.46	\$1.56	\$0.89
Seasonal	\$12.99			\$10.90		
Annual	\$11.60					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.6539	5.1782	1.4189	6.6333	4.6213	2.9212
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Total	9.4848	7.0091	3.2499	8.4643	6.4522	4.7522
Seasonal	5.7282			6.1816		
Annual	6.0301					
(2) Primary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$1.456	\$0.278	\$0.006	\$0.583	\$0.128	\$0.018
Transmission	\$6.945	\$1.769	\$0.058	\$7.230	\$1.262	\$0.553
Distribution Substation	\$1.152	\$0.799	\$0.010	\$0.224	\$0.085	\$0.278
Total	\$9.55	\$2.85	\$0.07	\$8.04	\$1.47	\$0.85
Seasonal	\$12.47			\$10.36		
Annual	\$11.06					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.3671	4.9990	1.3779	6.3397	4.4309	2.8082
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Total	9.1569	6.7887	3.1677	8.1294	6.2206	4.5980
Seasonal	5.5520			5.9592		
Annual	5.8231					
(3) Transmission						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$1.352	\$0.258	\$0.006	\$0.535	\$0.117	\$0.016
Transmission	\$6.466	\$1.644	\$0.054	\$6.642	\$1.151	\$0.503
Distribution Substation						
Total	\$7.82	\$1.90	\$0.06	\$7.18	\$1.27	\$0.52
Seasonal	\$9.78			\$8.96		
Annual	\$9.24					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	6.9104	4.7113	1.3112	5.8811	4.1311	2.6292
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Total	8.6274	6.4283	3.0282	7.5981	5.8482	4.3462
Seasonal	5.2626			5.6017		
Annual	5.4883					
Note: ¹ Operating reserve includes both spinning and supplemental reserve.						

Table 36. 2012 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	7.9631	5.4107	1.5810	6.8462	4.8329	3.1306
Generation Capacity	1.9871	0.1866	0.0033	0.5085	0.1177	0.0089
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Transmission	6.1528	0.7714	0.0201	4.3254	0.7932	0.1875
Distribution Substation	0.9063	0.3090	0.0032	0.1177	0.0468	0.0823
Total	18.8403	8.5087	3.4385	13.6287	7.6215	5.2403
Seasonal	8.0298			8.0967		
Annual	8.0743					
(2) Primary						
Energy	7.6652	5.2234	1.5353	6.5436	4.6339	3.0099
Generation Capacity	1.9005	0.1784	0.0032	0.4826	0.1113	0.0084
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Transmission	5.8950	0.7384	0.0192	4.1081	0.7501	0.1768
Distribution Substation	0.8813	0.3005	0.0031	0.1145	0.0455	0.0800
Total	18.1318	8.2304	3.3505	13.0386	7.3306	5.0649
Seasonal	7.7619			7.7806		
Annual	7.7744					
(3) Transmission						
Energy	7.1905	4.9227	1.4607	6.0709	4.3207	2.8186
Generation Capacity	1.7648	0.1656	0.0029	0.4429	0.1015	0.0076
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Transmission	5.4889	0.6864	0.0179	3.7742	0.6846	0.1607
Distribution Substation						
Total	16.1613	7.4917	3.1986	12.0051	6.8239	4.7039
Seasonal	7.0722			7.2022		
Annual	7.1587					
	Note: ¹ Operating reserve includes both spinning and supplemental reserve.					

Table 37. 2012 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$2.60	\$0.50	\$0.01	\$0.99	\$0.22	\$0.03
Transmission	\$8.04	\$2.05	\$0.07	\$8.45	\$1.48	\$0.65
Distribution Substation	\$1.18	\$0.82	\$0.01	\$0.23	\$0.09	\$0.29
Total	\$11.82	\$3.37	\$0.09	\$9.67	\$1.79	\$0.97
Seasonal	\$15.28			\$12.42		
Annual	\$13.38					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.9631	5.4107	1.5810	6.8462	4.8329	3.1306
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Total	9.7941	7.2417	3.4120	8.6771	6.6638	4.9616
Seasonal	5.9422			6.3925		
Annual	6.2420					
(2) Primary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$2.484	\$0.474	\$0.011	\$0.942	\$0.208	\$0.029
Transmission	\$7.706	\$1.962	\$0.065	\$8.022	\$1.400	\$0.614
Distribution Substation	\$1.152	\$0.799	\$0.010	\$0.224	\$0.085	\$0.278
Total	\$11.34	\$3.24	\$0.09	\$9.19	\$1.69	\$0.92
Seasonal	\$14.66			\$11.80		
Annual	\$12.75					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.6652	5.2234	1.5353	6.5436	4.6339	3.0099
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Total	9.4550	7.0132	3.3250	8.3333	6.4237	4.7996
Seasonal	5.7588			6.1618		
Annual	6.0271					
(3) Transmission						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$2.307	\$0.440	\$0.010	\$0.865	\$0.189	\$0.026
Transmission	\$7.175	\$1.824	\$0.060	\$7.370	\$1.277	\$0.558
Distribution Substation						
Total	\$9.48	\$2.26	\$0.07	\$8.23	\$1.47	\$0.58
Seasonal	\$11.82			\$10.29		
Annual	\$10.80					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.1905	4.9227	1.4607	6.0709	4.3207	2.8186
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Total	8.9075	6.6397	3.1777	7.7880	6.0377	4.5356
Seasonal	5.4579			5.7912		
Annual	5.6798					
Note: ¹ Operating reserve includes both spinning and supplemental reserve.						

Table 38. 2013 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	8.3213	5.7761	1.9460	7.0875	5.0997	3.5123
Generation Capacity	3.2443	0.3046	0.0054	0.7921	0.1833	0.0138
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Transmission	6.0647	0.7604	0.0198	4.2634	0.7819	0.1848
Distribution Substation	0.9063	0.3090	0.0032	0.1177	0.0468	0.0823
Total	20.3674	8.9810	3.8053	14.0917	7.9426	5.6242
Seasonal	8.6421			8.4857		
Annual	8.5380					
(2) Primary						
Energy	8.0098	5.5761	1.8902	6.7746	4.8899	3.3773
Generation Capacity	3.1029	0.2913	0.0052	0.7518	0.1733	0.0130
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Transmission	5.8105	0.7278	0.0190	4.0493	0.7394	0.1743
Distribution Substation	0.8813	0.3005	0.0031	0.1145	0.0455	0.0800
Total	19.5943	8.6855	3.7071	13.4800	7.6379	5.4345
Seasonal	8.3517			8.1535		
Annual	8.2198					
(3) Transmission						
Energy	7.5137	5.2552	1.7991	6.2859	4.5597	3.1634
Generation Capacity	2.8813	0.2704	0.0048	0.6900	0.1582	0.0118
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Transmission	5.4103	0.6766	0.0177	3.7201	0.6748	0.1584
Distribution Substation						
Total	17.5223	7.9192	3.5386	12.4130	7.1096	5.0507
Seasonal	7.6263			7.5497		
Annual	7.5753					
Note: ¹ Operating reserve includes both spinning and supplemental reserve.						

Table 39. 2013 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$4.24	\$0.81	\$0.02	\$1.55	\$0.34	\$0.05
Transmission	\$7.93	\$2.02	\$0.07	\$8.33	\$1.46	\$0.64
Distribution Substation	\$1.18	\$0.82	\$0.01	\$0.23	\$0.09	\$0.29
Total	\$13.35	\$3.65	\$0.10	\$10.10	\$1.89	\$0.98
Seasonal	\$17.10			\$12.97		
Annual	\$14.34					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	8.3213	5.7761	1.9460	7.0875	5.0997	3.5123
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Total	10.1522	7.6070	3.7769	8.9185	6.9307	5.3432
Seasonal	6.3061			6.7072		
Annual	6.5731					
(2) Primary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$4.056	\$0.774	\$0.017	\$1.468	\$0.323	\$0.045
Transmission	\$7.595	\$1.934	\$0.064	\$7.907	\$1.380	\$0.605
Distribution Substation	\$1.152	\$0.799	\$0.010	\$0.224	\$0.085	\$0.278
Total	\$12.80	\$3.51	\$0.09	\$9.60	\$1.79	\$0.93
Seasonal	\$16.40			\$12.31		
Annual	\$13.68					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	8.0098	5.5761	1.8902	6.7746	4.8899	3.3773
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Total	9.7996	7.3659	3.6799	8.5644	6.6797	5.1671
Seasonal	6.1111			6.4642		
Annual	6.3462					
(3) Transmission						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$3.766	\$0.719	\$0.016	\$1.347	\$0.295	\$0.041
Transmission	\$7.072	\$1.798	\$0.059	\$7.264	\$1.259	\$0.550
Distribution Substation						
Total	\$10.84	\$2.52	\$0.08	\$8.61	\$1.55	\$0.59
Seasonal	\$13.43			\$10.76		
Annual	\$11.65					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.5137	5.2552	1.7991	6.2859	4.5597	3.1634
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Total	9.2307	6.9723	3.5161	8.0029	6.2767	4.8804
Seasonal	5.7915			6.0742		
Annual	5.9797					
Note: ¹ Operating reserve includes both spinning and supplemental reserve.						

Table 40. 2014 Summary of Marginal Generation, Transmission and Distribution Substation Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	----- (2010 Cents per kWh) -----					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Energy	8.5362	5.9787	2.1342	7.3227	5.3082	3.6101
Generation Capacity	3.4006	0.3193	0.0056	0.7963	0.1843	0.0139
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Transmission	5.9943	0.7515	0.0195	4.2139	0.7728	0.1827
Distribution Substation	0.9063	0.3090	0.0032	0.1177	0.0468	0.0823
Total	20.6684	9.1895	3.9935	14.2817	8.1430	5.7199
Seasonal	8.8578			8.6334		
Annual	8.7084					
(2) Primary						
Energy	8.2170	5.7719	2.0731	6.9996	5.0898	3.4715
Generation Capacity	3.2524	0.3053	0.0054	0.7558	0.1743	0.0131
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Transmission	5.7431	0.7193	0.0187	4.0023	0.7308	0.1723
Distribution Substation	0.8813	0.3005	0.0031	0.1145	0.0455	0.0800
Total	19.8836	8.8868	3.8901	13.6620	7.8301	5.5267
Seasonal	8.5604			8.2953		
Annual	8.3839					
(3) Transmission						
Energy	7.7084	5.4399	1.9735	6.4949	4.7458	3.2518
Generation Capacity	3.0201	0.2834	0.0050	0.6937	0.1590	0.0119
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Transmission	5.3475	0.6687	0.0175	3.6769	0.6670	0.1566
Distribution Substation						
Total	17.7931	8.1091	3.7130	12.5825	7.2888	5.1373
Seasonal	7.8235			7.6823		
Annual	7.7295					
Note: ¹ Operating reserve includes both spinning and supplemental reserve.						

Table 41. 2014 Summary of Marginal Time-varying Costs, with Capacity Costs Stated on a per-kW Basis

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) Secondary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$4.45	\$0.85	\$0.02	\$1.56	\$0.34	\$0.05
Transmission	\$7.84	\$2.00	\$0.07	\$8.23	\$1.44	\$0.63
Distribution Substation	\$1.18	\$0.82	\$0.01	\$0.23	\$0.09	\$0.29
Total	\$13.47	\$3.67	\$0.10	\$10.01	\$1.87	\$0.97
Seasonal	\$17.23			\$12.85		
Annual	\$14.31					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	8.5362	5.9787	2.1342	7.3227	5.3082	3.6101
Regulating Reserve	1.0960	1.0960	1.0960	1.0960	1.0960	1.0960
Operating Reserve ¹	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
Total	10.3672	7.8096	3.9651	9.1537	7.1392	5.4411
Seasonal	6.5043			6.8701		
Annual	6.7479					
(2) Primary						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$4.251	\$0.812	\$0.018	\$1.476	\$0.325	\$0.046
Transmission	\$7.507	\$1.912	\$0.063	\$7.815	\$1.364	\$0.598
Distribution Substation	\$1.152	\$0.799	\$0.010	\$0.224	\$0.085	\$0.278
Total	\$12.91	\$3.52	\$0.09	\$9.51	\$1.77	\$0.92
Seasonal	\$16.52			\$12.21		
Annual	\$13.65					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	8.2170	5.7719	2.0731	6.9996	5.0898	3.4715
Regulating Reserve	1.0714	1.0714	1.0714	1.0714	1.0714	1.0714
Operating Reserve ¹	0.7184	0.7184	0.7184	0.7184	0.7184	0.7184
Total	10.0068	7.5617	3.8629	8.7894	6.8795	5.2613
Seasonal	6.3030			6.6205		
Annual	6.5144					
(3) Transmission						
Monthly Costs per Kilowatt (2010 Dollars per Kilowatt)						
Generation Capacity	\$3.948	\$0.753	\$0.017	\$1.355	\$0.297	\$0.041
Transmission	\$6.990	\$1.777	\$0.059	\$7.180	\$1.244	\$0.544
Distribution Substation						
Total	\$10.94	\$2.53	\$0.08	\$8.53	\$1.54	\$0.58
Seasonal	\$13.54			\$10.66		
Annual	\$11.62					
Costs per kWh (2010 Cents per kWh)						
Energy Costs	7.7084	5.4399	1.9735	6.4949	4.7458	3.2518
Regulating Reserve	1.0278	1.0278	1.0278	1.0278	1.0278	1.0278
Operating Reserve ¹	0.6892	0.6892	0.6892	0.6892	0.6892	0.6892
Total	9.4254	7.1569	3.6905	8.2119	6.4628	4.9689
Seasonal	5.9732			6.2199		
Annual	6.1375					
Note: ¹ Operating reserve includes both spinning and supplemental reserve.						

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