825 N.E. Multnomah St.
Portland, OR 97232

PACIFICORP
PACIFIC POWER UTAH POWER

January 17, 2006

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

VIA ELECTRONIC FILING

Attn: Vikie Bailey-Goggins, Administrator
Regulatory and Technical Support

Re: PacifiCorp's Simultaneous Opening Testimony and Exhibits in Docket No. UE-170

Enclosed for filing is an original and 5 copies of PacifiCorp's Simultaneous Opening Testimony and Exhibits in Docket No. UE-170. Copies of this filing have been served on the UE-170 Service List.

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com.

By Fax: (503) 813-6060

By regular mail: Data Request Response Center
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With copies to: Katherine A. McDowell
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Informal inquiries may be directed to Laura Beane, Regulatory Manager at (503) 813-5542.

Very truly yours,

D. Douglas Larson
Vice President, Regulation

cc: Service List
Enclosures

I hereby certify that on this 17th day of January 2006, I caused to be served, via email if available and overnight delivery, a true and correct copy of PacifiCorp's Simultaneous Opening Direct Testimony and Exhibits in Docket No. UE-170.

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Oregon Public Utility Commission

Peggy Ryan

Peggy Ryan
Supervisor Regulatory Administration

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

UE 170

In the Matter of	)
PACIFIC POWER & LIGHT (dba PacifiCorp	)
Request for a General Rate Increase in the	)
Company's Oregon Annual Revenues	)
(Klamath River Basin Irrigator Rates).	)

PACIFICORP

Simultaneous Opening Direct Testimony and Exhibits

January 2006

1214 Griffith
Testimony

Case UE-170
PPL Exhibit 1214
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of William R. Griffith

Rates

January 2006

1 **Q. Are you the same William R. Griffith who presented direct testimony in this**
2 **docket?**
3 A. Yes, I am.
4 **Purpose of Testimony**
5 **Q. What is the purpose of your testimony?**
6 A. My testimony addresses issues 2 and 3 of this proceeding:
7 Issue 2: What are the appropriate rates PacifiCorp should charge the Klamath
8 Basin Irrigators for electric service?
9 Issue 3: If any rate change affecting these customers is implemented, how and
10 when should these customers be transitioned from the rates established in the
11 historical contracts?
12 **Appropriate Rates for Klamath River Basin Irrigators**
13 **Q. Who are the Klamath River Basin Irrigators that are the subject of your**
14 **testimony?**
15 A. The Klamath River Basin Irrigators, or "Klamath Basin Customers," are the
16 customers receiving electric service at the rates specified in the 1956 "USBR
17 Contract" and the "UKRB Contract." The USBR Contract provides for
18 discounted rates for "On-Project" customers (customers within the Klamath River
19 Basin irrigation project boundaries), and the UKRB Contract provides for
20 discounted electric rates for "Off-Project" irrigation customers within the Upper
21 Klamath River Basin outside of the irrigation project boundaries.

1 **Q. What is the appropriate rate under which Klamath River Basin Irrigators**
2 **should be served?**
3 A. The Klamath River Basin Irrigators should be served under the same rates as all
4 other similarly situated Oregon customers. For qualifying irrigation customers,
5 Schedule 41, Agricultural Pumping Service is the applicable delivery service
6 tariff.
7 If some of these customers do not qualify for Schedule 41 because of end
8 use or load size characteristics either now or in the future, those customers should
9 be served from the same delivery service tariffs applicable to all other similarly
10 situated general service customers--General Service Schedules 23, 28, 30 or 48,
11 depending on load size. In addition, those customers should have the same supply
12 service options available to them as all other similarly situated customers,
13 including standard offer supply service and direct access supply.
14 **Q. When should the transition to standard tariff rates for the Klamath Basin**
15 **Customers occur?**
16 A. The transition should begin April 17, 2006. It is my understanding that while the
17 Off-Project irrigators claim that their contract will never expire, there is no
18 dispute that the USBR Contract expires April 16, 2006. Without addressing the
19 legal arguments presented by the Company on this issue, I don't believe there is
20 any reasonable justification for continuing the UKRB Contract rates past the date
21 on which the On-Project customers' contract rates expire.

1 **Q. In the past, have special contract customers been moved to standard tariff**
2 **service upon contract expiration?**
3 A. Yes. Every expired special contract in Oregon of which I am aware has resulted
4 in a return to standard tariff service upon its final expiration.
5 **Q. If the Commission ordered the Company to serve Klamath River Basin**
6 **Irrigators under standard tariff rates as described above, what rates could**
7 **the Company bill these customers?**
8 A. Serving Klamath River Basin Irrigators under standard tariff rates would result in
9 bill increases in excess of 50 percent in the first year. Senate Bill 81, passed in the
10 Oregon 2005 legislative session, indicates that for qualifying Klamath River Basin
11 customers, the Commission shall require the Company to mitigate rate increases
12 and hold them to no more than 50 percent per year for seven years by means of
13 rate credits. Under Senate Bill 81, the full cost of providing rate credits is to be
14 spread equally among all other customers.
15 If the Commission ordered the Company to serve Klamath River Basin
16 Irrigators under standard tariff rates, in the first year, the Company could
17 implement SB 81 by increasing the rates under the current contract by 50 percent
18 and computing charges for these amounts. We believe this would be easy to
19 understand for customers (particularly given the differences in rate design
20 between the contract rate and standard tariff rates) and would reflect the intent of
21 SB 81. At the same time, the Company would also show a second alternate
22 billing for each customer using the standard tariff rate ordered by the
23 Commission. The Company would compute the dollar difference between the

1 charges under SB 81 and the alternate standard tariff billing and show that amount
2 as a rate credit. The total annual amount of these dollar differences for this class
3 of customers as defined under SB 81 would equal the first year rate credits
4 applicable to these customers. The full cost of providing these rate credits would
5 be spread equally among all other Oregon customers. Exhibit PPL 1215 shows a
6 billing example.

7 **Q. As you indicated, Senate Bill 81 requires that rate impacts must be no more**
8 **than 50 percent per year for seven years following termination of the**
9 **contract. What does the Company propose after the first year of**
10 **implementation?**

11 A. Assuming Senate Bill 81 remains in effect, in the subsequent years PacifiCorp
12 could continue to implement SB 81 by increasing the applicable charges billed to
13 the qualifying customers by 50 percent per year. At the same time, the Company
14 would continue to show an alternate billing for each customer on standard tariff.
15 The Company would continue to compute the dollar difference between the
16 charges billed under SB 81 and the alternate standard tariff billing. The total
17 annual amount of these dollar differences for this class of customers (as defined
18 under SB 81) for the mitigated rate and the standard tariff rate would equal the
19 rate credits applicable to these customers per year. The cost of providing these
20 rate credits would be spread equally among all other Oregon customers. At the
21 end of seven years, these Klamath Basin customers would be served under
22 standard tariff rates.

1 Q. Do qualifying Klamath Basin Customers currently receive the BPA credit
2 (Schedule 98) at a rate lower than other qualifying customers?
3 A. Yes.
4 **Q. How does the Company propose that Schedule 98 be modified for Klamath**
5 **Basin Customers on April 17, 2006 in response to Senate Bill 81?**
6 A. Based on the seven year timeframe in SB 81, the Company proposes that the BPA
7 credit (Schedule 98) currently being applied to Klamath Basin Customers
8 (Schedule 33) be increased by 0.08 cents per kWh per year for seven years or until
9 the Klamath Basin Customer's credit is equivalent to the charge being applied to
10 other customers, whichever comes first. The current credit being applied to
11 Klamath Basin Customers is 0.488 cents per kWh; for other customers, the credit
12 is 1.026 cents per kWh. Under this proposal, at current rates, the credit applied to
13 Klamath Basin Customers would come to equal the credit being applied to other
14 customers in seven years.
15 **Q. To which customers does the Company believe the SB 81 rate mitigation**
16 **language applies?**
17 A. We believe this language means that the current metering points for current
18 Klamath Basin Customers on contract rates are eligible for rate mitigation under
19 SB 81. In no case should rate mitigation apply to new customers who begin
20 receiving service after April 16, 2006, whether or not service was previously
21 provided at the metering point under either the USBR Contract or the UKRB
22 Contract. Moreover, if an existing Klamath Basin customer has a new metering
23 point location for land that had not been previously served under contract rates,

1 then SB 81 rate mitigation should not apply. Generally, new metering points that
2 were not previously served under the USBR or UKRB Contract rates are not
3 eligible for rate mitigation under SB 81.

4 **Q. Are there cases where a new metering point for an existing Klamath Basin**
5 **Customer may be eligible for rate mitigation under SB 81?**

6 A. Yes, there may be. For example, if an existing Klamath Contract customer
7 combined two existing metering points into one new metering point to irrigate the
8 same land, we believe that the energy used at this new metering point may be
9 eligible for mitigation, since energy use and application would be virtually
10 unchanged; however, any new line extension costs would be subject to standard
11 line extension tariffs.

12 **Q. Do you agree with the testimony of Mr. Schoenbeck filed earlier in this**
13 **docket that Klamath Basin Customers (Schedule 33 customers) should be**
14 **served on a standard delivery service tariff separate from Schedule 41?**

15 A. No. Schedule 41 is applicable to agricultural pumping loads under 1,000 kW. It
16 is designed for customers with seasonal usage and incorporates an annual load
17 size charge instead of monthly basic and demand charges in order to recognize the
18 seasonal nature of these customers. The Schedule 41 rate structure is similar to
19 agricultural pumping tariffs in other states served by the Company. As long as
20 customers meet the applicability criteria of Schedule 41, it is appropriate to serve
21 qualifying agricultural pumping loads under this tariff structure in Oregon.

22 In addition to end use similarities, Exhibit PPL/1210 shows that the
23 Klamath Basin Irrigators (Schedule 33) have usage characteristics not unlike

1 Schedule 41 customers. It shows that both groups contain a full range of customer
2 usage characteristics, from small to large. While Schedule 33 customers are
3 somewhat larger on average, Exhibit PPL/1210 shows that both Schedule 33 and
4 Schedule 41 customers cover a full range of usage from zero usage (inactive
5 accounts) to usage over 1,000 MWh per year. In fact, it appears that the only
6 unique characteristics shared by Klamath River Basin Irrigators are a common
7 geography along with the extremely low electric prices they have paid for 50 years
8 under the USBR and UKRB Contracts. We do not believe these are reasonable
9 criteria for a separate rate schedule in the future.

10 **Q. Does this conclude your supplemental testimony?**

11 A. Yes it does.

1215 Griffith
Exhibit

Case UE –170
PPL Exhibit 1215
Witness: William R. Griffith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of William R. Griffith

Customer Frequency by Annual kWh

Test Period April 2003 to March 2004 - Actual

January 2006

Table 1214 - 1
PacifiCorp - State of Oregon
Customer Frequency by Annual kWh
Test Period April 2003 to March 2004 - Actual

	% of Number of Customers	
Annual kWh	**Sch 33**	**Sch 41**
A: 0	12.30%	18.49%
B: 1 - 500	4.61%	5.98%
C: 501 - 1,000	1.80%	4.54%
D: 1,001 - 2,000	3.04%	6.14%
E: 2,001 - 5,000	6.17%	12.96%
F: 5,001 - 10,000	7.92%	13.55%
G: 10,001 - 15,000	7.51%	8.19%
H: 15,001 - 20,000	6.03%	6.00%
I: 20,001 - 30,000	10.46%	7.30%
J: 30,001 - 50,000	13.17%	8.78%
K: 50,001 - 80,000	10.32%	4.63%
L: 80,001 - 100,000	3.27%	1.18%
M: 100,001 - 150,000	5.34%	1.27%
N: 150,001 - 200,000	3.22%	0.45%
O: 200,001 - 250,000	1.89%	0.13%
P: 250,001 - 300,000	1.52%	0.09%
Q: 300,001 - 400,000	0.74%	0.10%
R: 400,001 - 600,000	0.46%	0.04%
S: 600,001 - 1,000,000	0.18%	0.15%
T: > 1,000,000	0.05%	0.04%
Overall	100.00%	100.00%

1700 Anderberg
Testimony

Case UE-170
PPL Exhibit 1700
Witness: Karl D. Anderberg

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Karl D. Anderberg

Cost of Service

January 2006

1 **Q. Please state your name, business address and position with PacifiCorp (the**
2 **Company).**
3 A. My name is Karl D. Anderberg. My business address is 825 N. E. Multnomah,
4 Suite 300, Portland, Oregon 97232, where I am currently employed as the Cost of
5 Service Manager in the Regulation Department.
6 **Qualifications**
7 **Q. Please briefly describe your education and business experience.**
8 A. I received a BS Degree in Accounting from the University of Utah in 1978. In
9 addition to formal education, I have attended various educational, professional
10 and electric industry seminars during my career at the Company. I am a licensed
11 CPA in the state of Utah. I joined the Company in 1985, and have held various
12 accounting and regulatory positions prior to assuming my current responsibilities.
13 **Q. What are your responsibilities?**
14 A. My primary responsibilities are to manage and oversee the development and
15 reporting of the class cost of service studies in the six jurisdictions in which
16 PacifiCorp operates.
17 **Purpose of Testimony**
18 **Q. What is the purpose of your testimony?**
19 A. I present Exhibit PPL 1701, PacifiCorp's December 2006 Marginal Cost Study for
20 the State of Oregon that includes the Klamath River On-Project and Off-Project
21 irrigation customers (current Schedule No. 33). In this Marginal Cost Study, and
22 for pricing purposes, the current Schedule 33 customers have been included under
23 Schedule No. 41, Agricultural Pumping Service, and Schedule No. 48, Large

General Service – 1,000 KW and Over, based on load characteristics.

I also address the issue of what the appropriate electric rates for Klamath River Basin irrigators should be, including sub-issues 2a and 2b from the Administrative Law Judge's August 17, 2005 ruling:

> Issue 2a: Are the current rates under the On-Project and Off-Project Agreements justifiable according to the "applicable statutory standard to the setting of electric rates for irrigators located within the Klamath Basin?" (determined by the Commission in Order No. 05-1202 to be the same "just and reasonable" standard applicable to rates set for all other customers in Oregon).
>
> Issue 2b: Should the Klamath Basin irrigation customers be included in the standard class of irrigation customers, or is there substantial and reasonable basis for establishing a separate and distinct class of irrigation customers in the Klamath Basin for purposes of service and rates?

Marginal Cost Study

Q. Please describe PacifiCorp's Marginal Cost study that accompanies this filing.

A. PPL Exhibit 1701 contains PacifiCorp's December 2006 Marginal Cost Study for the State of Oregon, including the Klamath River Basin irrigation customers. This study shows, by customer class, PacifiCorp's marginal cost of resources required to produce one additional unit of electricity or to add one additional customer. The difference between this study and the most recent marginal cost study filed in this case (PPL Exhibit 419) is that the current Schedule 33 customers (receiving service under the On-Project and Off-Project Agreements) are included with other similarly situated irrigation customers in either Schedule 41 or Schedule 48. In the prior study, Schedule 33 customers were excluded. PPL Exhibit 1701

1 contains seven summary tables followed by 17 sections of supporting data. A
2 summary of the Marginal Cost Study results is shown in PPL Exhibit 1702.

3 **Q. Was PPL Exhibit 1701 developed using the same marginal cost methodology**
4 **previously used in this case?**

5 A. Yes. The Marginal Cost Study filed here was prepared using the same
6 methodology that was used by the Company in the earlier phase of this case. This
7 is the same methodology that has been accepted by the Oregon Commission in
8 previous Company filings.

9 **Klamath Basin Irrigation**

10 **Q. Are the current rates under the On-Project and Off-Project Agreements just**
11 **and reasonable?**

12 A. No, the current rates under the On-Project and Off-Project Agreements are not just
13 and reasonable. They do not produce revenues that are anywhere near sufficient
14 to cover relevant short and long-run costs necessary to provide service to these
15 customers. The current rates of the On-Project and Off-Project Klamath irrigation
16 customers are dramatically below cost of service. Energy rates for most On-
17 Project and Off-project irrigation customers are currently 0.6 cents and 0.75 per
18 kWh, respectively. The overall average cost to serve Pacific Power's Oregon
19 irrigation customers is 10.25 cents per kWh (PPL Exhibit 1701;($21,182,000
20 (Table 4, Column R, Line 41)/206,654 MWH (Table 3, Column Q, Line 10)).
21 That is, the average cost to serve irrigation customers is 13 to 17 times greater
22 than the rates being paid by most of the customers in these two groups.

23 **Q. Should the Klamath Basin irrigation customers be included in the standard**

1 **class of irrigation customers?**

2 A. Yes. These customers should be served under the same tariff schedules applicable
3 to other customers with similar service characteristics. Irrigation customers with
4 loads less than 1,000 kW should be served under Schedule 41, while irrigation
5 customers with load sizes 1,000 kW and greater should be served under Schedule
6 48. These requirements have been reflected in the Marginal Cost Study submitted
7 with this testimony as PPL Exhibit 1701. As was discussed in both the
8 Company's direct and rebuttal testimony in the earlier phase of this case, and as
9 further discussed by Mr. Griffith in his supplemental testimony, PacifiCorp
10 believes that the Klamath River Basin customers should be served under the same
11 rates as all other similarly situated customers served by the Company in Oregon.

12 **Q. How have these customers been treated in the attached Marginal Cost**
13 **Study?**

14 A. In the Marginal Cost Study, the Klamath Basin irrigation customers have been
15 combined with other similarly situated customers on Schedule 41, Agricultural
16 Pumping Service, and Schedule 48, Large General Service – 1,000 KW and Over,
17 in developing class revenue requirements.

18 **Q. Has PacifiCorp previously filed a cost of service study in this proceeding that**
19 **divides the Schedule 33 customers between Schedules 41 and 48?**

20 A. No.

21 **Q. Why does the Marginal Cost Study accompanying this testimony now divide**
22 **the Schedule 33 customers between Schedules 41 and 48?**

23 A. Additional billing analysis indicates that one Klamath Basin Irrigation customer

1 has a load size of 1,000 kW or greater, which qualifies for service under Schedule
2 48. All other Klamath Basin Irrigation customers have load characteristics similar
3 to those served under Schedule 41. The Marginal Cost Study accompanying this
4 testimony assigns the Schedule 33 customers to the classes with which they share
5 similar load characteristics.

6 **Q. Are there sufficient similarities between the Klamath Basin and other**
7 **Oregon irrigation customers to support a single class of service?**

8 A. Yes. Both groups have a number of similar characteristics. Both Schedule 33 and
9 Schedule 41 customers take service for agricultural pumping and are seasonal in
10 nature. The majority of their usage occurs in the summer. Nearly all of the
11 customers in both groups take service at secondary distribution voltage. Load
12 factors for the two groups are nearly identical. Based on the Company's billing
13 data, the aggregate annual load factors for the Klamath Basin irrigation customers
14 and the current customers on Schedule 41 are both between 12 percent and 13
15 percent.

16 **Q. Are there any service characteristics of the Klamath irrigation customers**
17 **that differ significantly from the other Oregon irrigation customers?**

18 A. No. While on average, the energy consumption of Schedule 33 customers is
19 somewhat higher than the Oregon irrigation customers currently served on
20 Schedule 41, as Mr. Griffith explains, both customer groups contain a full range
21 of customer usage characteristics, from small to large.

1 **Q. Is the higher energy usage of Schedule 33 customers sufficient justification to**
2 **create a separate customer class for the Klamath irrigation customers?**
3 A. No. While energy consumption may differ somewhat between the current
4 Schedule 41 and Schedule 33 customers, there are individual customers of various
5 sizes in each group. There are smaller customers and larger customers currently
6 served on Schedule 41 and smaller and larger customers currently served on the
7 On-Project and Off-Project contracts. Placing the Klamath Basin irrigation
8 customers in a separate class has no cost of service basis, and it would mean that a
9 Klamath Basin customer who receives the same service for irrigation would pay a
10 different price than a customer of the same size, voltage and load factor located in
11 another part of Pacific Power's Oregon service territory.
12 **Q. Does this conclude your direct testimony?**
13 A. Yes.

1701 Anderberg
Exhibit

Case UE –170
PPL Exhibit 1701
Witness: Karl D. Anderberg

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Karl D. Anderberg

State of Oregon

Marginal Cost Study

January 2006

PacifiCorp
Oregon Marginal Cost Study
December 2006
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PPL/1701
Anderberg/1

Table 1

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Demand & Energy in Mills/kWh
December 2006 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)
			Energy			Demand & Energy		
Line	Description		1 Year	10 Year	20 Year	1 Year	10 Year	20 Year
1	Res - Schedule 4	(sec)	31.13	33.10	31.85	31.13	60.85	60.06
2								
3	GS - Schedule 23							
4	0-15 kW	(sec)	31.13	33.10	31.85	31.13	62.52	61.77
5	15+ kW	(sec)	31.13	33.10	31.85	31.13	65.58	64.83
6	Primary	(pri)	30.22	32.18	30.97	30.22	62.40	62.93
7								
8	GS - Schedule 28							
9	0-50 kW	(sec)	31.13	33.10	31.85	31.13	58.80	58.02
10	51-100 kW	(sec)	31.13	33.10	31.85	31.13	57.61	56.80
11	> 101kW	(sec)	31.13	33.10	31.85	31.13	55.92	55.09
12	Primary	(pri)	30.29	32.17	30.97	30.29	54.35	53.53
13								
14	GS - Schedule 30							
15	0-300 kW	(sec)	31.13	33.10	31.85	31.13	57.12	56.08
16	301+ kW	(sec)	31.13	33.10	31.85	31.13	56.29	55.26
17	Primary	(pri)	30.27	32.18	30.97	30.27	54.60	53.81
18								
19	LPS - Schedule 48T							
20	1 - 4 MW	(sec)	31.13	33.10	31.85	31.13	53.94	53.11
21	1 - 4 MW	(pri)	30.27	32.18	30.97	30.27	51.14	50.31
22	> 4 MW	(sec)	31.13	33.10	31.85	31.13	47.09	46.20
23	> 4 MW	(pri)	30.27	32.18	30.97	30.27	45.65	44.79
24								
25	Trans	(trn)	29.60	31.47	30.29	29.60	41.22	40.35
26								
27								
28	Schedule 41- Irrigation	(sec)	31.12	33.10	31.85	31.12	70.51	69.73

Sources:
(A) Tab 2.13 (1 Year MC:) `1 Year Marginal Costs by Load Class'
(B) Tab 2.11 (10 Yr FC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(C) Tab 2.3 (Table 4:) `20 Year Marginal Cost By Load Class March 2004 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
(D) Column (A)
(E) Tab 2.11 (10 Yr FC:) `10 Year Marginal Cost By Load Class'
Tab 2.10 (10 Yr UC:) `10 Year Run Costing Inputs and Customer Data Marginal Unit Costs'
(F) Tab 2.4 (Table 4:) `20 Year Marginal Cost By Load Class March 2004 Dollars'
Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'

Energy costs include both generation and transmission energy-related costs.

Table 2

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Costs
Commitment and Billing in $ / Customer / Month
December 2006 Dollars

Line	Description		(A) 1 Year 1&3 Phase	(B) 10 & 20 Year 1&3 Phase
1	Res - Schedule 4	(sec)	$10.98	$26.42
2				
3	GS - Schedule 23			
4	0-15 kW	(sec)	11.69	33.06
5	15+ kW	(sec)	21.67	45.98
6	Primary	(pri)	98.07	110.74
7				
8	GS - Schedule 28			
9	0-50 kW	(sec)	28.76	53.85
10	51-100 kW	(sec)	29.37	55.89
11	> 101kW	(sec)	59.61	87.58
12	Primary	(pri)	104.45	111.41
13				
14	GS - Schedule 30			
15	0-300 kW	(sec)	70.64	103.11
16	301+ kW	(sec)	70.65	103.25
17	Primary	(pri)	115.45	120.72
18				
19	Total			
20	1 - 4 MW	(sec)	243.89	292.44
21	1 - 4 MW	(pri)	252.51	254.86
22	> 4 MW	(sec)	243.89	290.09
23	> 4 MW	(pri)	252.51	252.51
24	Trans	(trn)	2,082.26	2,082.26
25				
26				
27	Schedule 41- Irrigation	(sec)	15.45	74.92

Footnote:
Short-run commitment and billing costs include the cost of metering, meter overhead and maintenance, service drops, service drop overhead and maintenance, customer accounting and informational expenses, and billing expenses.

Sources:
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Table 3

PacifiCorp
Oregon Marginal Cost Study
20 Year Costing Inputs and Customer Data
Marginal Unit Costs
December 2006 Dollars

Line	Description	(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) > 101kW (sec)	(H) Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) 301+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trans (tm)	(Q) Irrigation Sch 41 (sec)
	Billing Units																	
	Demand																	
1	Load Factors	68.69%	63.78%	63.54%	63.61%	68.64%	73.34%	76.39%	75.96%	70.45%	72.72%	72.48%	75.94%	79.79%	88.09%	86.79%	97.50%	69.16%
2		60.88%	65.07%	52.58%	55.66%	63.23%	64.11%	71.53%	70.56%	65.31%	67.89%	67.61%	71.07%	76.29%	88.21%	87.47%	N/A	69.16%
3		29.41%	34.20%	57.56%	N/A	38.67%	55.16%	66.08%	N/A	59.65%	64.54%	N/A	69.60%	N/A	91.97%	N/A	N/A	47.05%
4																		
5	Peak Mw @ Generator	928	133	85	0	107	103	148	4	46	187	15	136	68	12	201	75	38
6		1,047	131	103	0	116	118	158	4	50	200	17	145	71	12	199	N/A	38
7		2,167	249	94	N/A	189	137	171	N/A	N/A	N/A	N/A	148	N/A	11	N/A	N/A	55
8																		
9	Energy																	
10	Energy - Annual Mwh	5,079,177	678,078	432,675	728	582,614	602,504	902,113	22,353	260,390	1,080,762	91,525	821,613	444,269	82,940	1,428,559	614,130	206,654
11	Energy Loss Factor	1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0691	1.0995	1.0691	1.0995	1.0691	1.0454	1.0995
12	Energy - Annual Mwh	5,584,555	745,546	475,727	778	640,584	662,453	991,873	23,897	286,298	1,188,298	97,847	903,364	474,959	91,192	1,527,244	642,030	227,216
13																		
14	Customer																	
15	Annual Customers	460,491	63,230	5,457	29	4,643	3,099	2,006	54	312	646	56	138	56	3	35	1	8,338
16	Average Customers																	3,530
17																		
18	Unit Costs																	
19																		
20	Generation	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33	$69.33
21	Transmission	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85
22	Poles, Cond., Subst.	$62.16	$69.10	$69.10	$69.10	$54.24	$54.24	$54.24	$54.24	$49.89	$49.89	$49.89	$42.31	$42.31	$17.48	$16.23	$0.00	$124.84
23	Transformers	$0.88	$1.13	$1.13	$0.00	$1.13	$1.13	$1.13	$0.00	$1.13	$1.13	$0.00	$1.13	$0.00	$1.13	$0.00	$0.00	$1.13
24																		
25	Energy - @ Generator																	
26	Generation	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722
27	Transmission	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175
28																		
29	Poles	$85.61	$108.50	$108.50	$108.50	$59.56	$59.56	$59.56	$59.56	$45.12	$45.12	$45.12	$20.15	$20.15	$0.00	$0.00	$0.00	$291.12
30	Conductor	$34.31	$43.49	$43.49	$43.49	$23.87	$23.87	$23.87	$23.87	$18.08	$18.08	$18.08	$8.07	$8.07	$0.00	$0.00	$0.00	$116.68
31	Transformers	$65.39	$104.47	$139.66	$0.00	$217.55	$234.79	$252.20	$0.00	$326.51	$328.04	$0.00	$554.38	$0.00	$554.38	$0.00	$0.00	$305.81
32	Service Drop	$56.54	$73.26	$174.97	$0.00	182.47	188.90	401.00	-	400.28	399.92	-	$779.24	$0.00	$779.24	$0.00	$0.00	$0.00
33	Meters	$14.37	$15.87	$34.00	$1,125.73	34.97	35.81	186.59	1,125.73	187.67	188.18	1,125.73	$243.03	$1,125.73	$243.03	$1,125.73	$23,083	$35.20
34	Meter Reading	$10.44	$14.71	$14.71	$14.71	23.48	23.48	23.48	23.48	23.48	23.48	23.48	31.20	$31.20	$31.20	$31.20	$31.20	$28.18
35	Billing & Collections	$21.72	$20.45	$20.45	$20.45	50.90	50.90	50.90	50.90	50.90	50.90	50.90	783.50	$783.50	$783.50	$783.50	$783.50	$71.40
36	Uncollectables	$13.09	$2.29	$2.29	$2.29	24.43	24.43	24.43	24.43	130.14	130.14	130.14	707.44	$707.44	$707.44	$707.44	$707.44	$17.28
37	Customer Service / Other	$15.60	$13.67	$13.67	$13.67	28.90	28.90	28.90	28.90	55.15	55.15	55.15	382.25	$382.25	$382.25	$382.25	$382.25	$33.38
38	Total Commitment & Billing	$317.06	$396.71	$551.74	$1,328.85	$646.15	$670.65	$1,050.94	$1,336.88	$1,237.34	$1,239.01	$1,448.61	$3,509.25	$3,058.33	$3,481.04	$3,030.12	$24,987	$899.05

Sources:
Lines 1 - 3 Tab 17.4 (Cust Data 4:) `Customer Load Factors12 Months Ended December 2006'
Lines 10 & 15 Tab 17.2 (Cust Data 2:) `Customers and MWh's12 Months Ended December 2006 - Normalized'
Line 11 Tab 16.1 (Losses:) `Energy Loss Factors'
Line 20 Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
Line 21 Tab 6.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'
Line 22 Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'
Line 26 Tab 5.1 (Energy:) `Marginal Generation Energy Costs'
Line 27 Tab 2.6 (Table 6:) `Marginal Cost of Transmission Investment and Associated Expenses'
Lines 29 - 37 Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Table 4

PacifiCorp
Oregon Marginal Cost Study
20 Year Marginal Cost By Load Class
March 2004 Dollars
(Dollars in 000's)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)	(O)	(P)	(Q)	(R)	(S)
			Residential	General Service - Schedule 23			General Power - Schedule 28				General Power - Schedule 30			Large Power Service - Schedule 48T					Irrg	Sch 51,53,54
Line	Description	Total	(sec)	0-15 kW (sec)	15+ kW (sec)	Primary (pri)	0-50 kW (sec)	51-100 kW (sec)	> 101kW (sec)	Primary (pri)	0-300 kW (sec)	301+ kW (sec)	Primary (pri)	1 - 4 MW (sec)	1 - 4 M (pri)	> 4 MW (sec)	> 4 M (pri)	Trans (trn)	Sch 41 (sec)	Streetlighting (sec)
	Demand Related Marginal Cost																			
1	Generation	$158,489	$64,343	$9,251	$5,925	$10	$7,387	$7,149	$10,276	$249	$3,216	$12,932	$1,068	$9,414	$4,711	$819	$13,927	$5,212	$2,600	
2	Transmission	$29,376	$11,926	$1,715	$1,098	$2	$1,369	$1,325	$1,905	$46	$596	$2,397	$198	$1,745	$873	$152	$2,581	$966	$482	
3	Distribution																			
4	Poles	$37,113	$18,937	$2,739	$2,164	$4	$1,712	$1,745	$2,342	$57	$651	$2,601	$215	$1,435	$702	$13	$142	$0	$1,655	
5	Conductor	$62,263	$31,407	$4,456	$3,519	$5	$2,932	$2,990	$4,012	$98	$1,141	$4,552	$376	$2,662	$1,303	$27	$285	$0	$2,498	
6	Substations	$33,928	$14,752	$1,843	$1,455	$2	$1,629	$1,662	$2,230	$54	$705	$2,815	$233	$2,044	$1,001	$166	$2,808	$0	$528	
7	Subtotal: Pole, Cond, Subs	$133,303	$65,095	$9,037	$7,138	$11	$6,273	$6,397	$8,584	$209	$2,497	$9,968	$824	$6,140	$3,007	$206	$3,235	$0	$4,681	
8	Transformers	$3,097	$1,900	$282	$107	$0	$214	$156	$195	$0	$0	$0	$0	$168	$0	$13	$0	$0	$63	
9	Distribution subtotal	$136,400	$66,995	$9,320	$7,245	$11	$6,487	$6,553	$8,779	$209	$2,497	$9,968	$824	$6,308	$3,007	$219	$3,235	$0	$4,744	
10																				
11	Total Demand Related	$324,265	$143,264	$20,286	$14,268	$23	$15,243	$15,027	$20,960	$504	$6,309	$25,297	$2,090	$17,467	$8,591	$1,190	$19,743	$6,178	$7,826	
12	(Lines 1+2+9)																			
13																				
14	Energy Related Marginal Cost																			
15	Generation Energy Related	$397,192	$152,012	$20,294	$12,949	$21	$17,437	$18,032	$26,999	$650	$7,793	$32,345	$2,663	$24,590	$12,928	$2,482	$41,572	$17,476	$6,185	$763
16	Transmission Energy Related	$25,555	$9,780	$1,306	$833	$1	$1,122	$1,160	$1,737	$42	$501	$2,081	$171	$1,582	$832	$160	$2,675	$1,124	$398	$49
17	Total Energy	$422,747	$161,792	$21,599	$13,782	$23	$18,559	$19,192	$28,736	$692	$8,294	$34,427	$2,835	$26,172	$13,760	$2,642	$44,246	$18,600	$6,583	$813
18																				
19	Customer Related Marginal Cost																			
20	Poles	$52,922	$39,422	$6,861	$592	$3	$277	$184	$120	$3	$14	$30	$3	$3	$1	$0	$0	$0	$2,427	$2,984
21	Conductor	$20,056	$15,799	$2,749	$237	$1	$111	$73	$48	$1	$5	$12	$1	$1	$0	$0	$0	$0	$973	$43
22	Transformers	$42,699	$30,110	$6,606	$762	$0	$1,010	$728	$507	$0	$102	$211	$0	$76	$0	$1	$0	$0	$2,549	$37
23	Service Drops	$34,354	$26,038	$4,632	$955	$0	$847	$585	$804	$0	$125	$258	$0	$107	$0	$3	$0	$0	$0	
24	Meters	$9,244	$6,616	$1,004	$186	$33	$162	$111	$374	$61	$59	$122	$63	$34	$63	$1	$39	$23	$294	$1
25	Meter Reading	$6,179	$4,805	$930	$80	$0	$109	$73	$47	$1	$7	$15	$1	$4	$2	$0	$1	$0	$99	$1
26	Billing & Collections	$12,411	$10,001	$1,293	$112	$1	$236	$158	$102	$3	$16	$33	$3	$108	$44	$2	$27	$1	$252	$19
27	Uncollectables	$6,780	$6,026	$145	$13	$0	$113	$76	$49	$1	$41	$84	$7	$98	$40	$2	$25	$1	$61	$0
28	Customer Service / Other	$8,680	$7,185	$864	$75	$0	$134	$90	$58	$2	$17	$36	$3	$53	$21	$1	$13	$0	$118	$9
29	Total Commitment & Billing Rel.	$193,326	$146,004	$25,084	$3,010	$38	$3,001	$2,078	$2,109	$72	$386	$800	$81	$483	$171	$10	$106	$25	$6,773	$3,095
30																				
31	Total Revenue @ Full MC																			
32	Generation	$555,681	$216,355	$29,545	$18,874	$31	$24,824	$25,181	$37,275	$899	$11,009	$45,277	$3,731	$34,004	$17,639	$3,301	$55,499	$22,688	$8,785	$763
33	Transmission	$54,931	$21,706	$3,021	$1,931	$3	$2,491	$2,485	$3,642	$88	$1,097	$4,478	$369	$3,327	$1,705	$312	$5,256	$2,090	$880	$49
34	Distribution	$286,433	$178,365	$30,167	$9,790	$15	$8,732	$8,124	$10,257	$213	$2,743	$10,478	$828	$6,495	$3,008	$223	$3,235	$0	$10,694	$3,065
35	Customer - Billing	$12,411	$10,001	$1,293	$112	$1	$236	$158	$102	$3	$16	$33	$3	$108	$44	$2	$27	$1	$252	$19
36	Customer - Metering	$15,422	$11,422	$1,934	$266	$33	$271	$184	$421	$62	$66	$137	$64	$38	$65	$1	$40	$23	$393	$1
37	Customer - Other	$8,680	$7,185	$864	$75	$0	$134	$90	$58	$2	$17	$36	$3	$53	$21	$1	$13	$0	$118	$9
38	Revenue (less Uncollectables)	$933,558	$445,034	$66,824	$31,048	$84	$36,689	$36,221	$51,756	$1,267	$14,948	$60,439	$4,999	$44,024	$22,482	$3,840	$64,070	$24,803	$21,122	$3,907
39																				
40	Customer - Uncollectables	$6,780	$6,026	$145	$13	$0	$113	$76	$49	$1	$41	$84	$7	$98	$40	$2	$25	$1	$61	$0
41	Total Revenue	$940,338	$451,060	$66,969	$31,060	$84	$36,802	$36,297	$51,805	$1,268	$14,989	$60,523	$5,007	$44,122	$22,522	$3,842	$64,095	$24,803	$21,182	$3,907

Source: Tab 2.3 (Table 3:) `20 Year Costing Inputs and Customer Data Marginal Unit Costs'
Tab 2.7 (Table 7:) `Marginal Distribution & Billing Costs By Load Size'

Line 1 Generation (Table 3, Row 5) x (Table 3, Row 20)/1000
Line 2 Transmission (Table 3, Row 5) x (Table 3, Row 21)/1000
Lines 4-6 Poles, Cond., Subst. (Table 3, Row 6) x (Table 7, Row 1 - 3) x (1 + .2889) (Dist OM, Row 32)
Line 8 Transformers (Table 3, Row 7) x (Table 7, Row 7) x (1 + .2889) (Dist OM, Row 32)
Lines 15-16 Energy Related (Table 3, Row 12) x (Table 3, Row 26 - 27)
Lines 20-29 Commitment Related (Table 3, Row 15) x (Table 7, Row 13 - 27) including O&M Adders

PPL/1701
Anderberg/5

Table 5

PacifiCorp
Oregon Marginal Cost Study
Summary of Marginal Generation Costs
In Nominal Dollars

Year		(A) Resource Cost (Mills / kWh) (B) + (C)	(B) Energy Only (Mills / kWh)	(C) Capacity Only (Mills / kWh)	(D) Capacity Only ($ / kW)
2006		30.79	28.31	2.48	$18.49
2007		43.28	33.10	10.18	$75.81
2008		44.23	33.79	10.44	$77.71
2009		43.97	33.27	10.70	$79.65
2010		42.01	31.05	10.96	$81.64
2011		41.30	30.06	11.24	$83.69
2012		42.52	31.00	11.52	$85.78
2013		43.75	31.94	11.81	$87.92
2014		41.11	29.01	12.10	$90.12
2015		42.07	29.66	12.41	$92.37
2016		44.25	31.53	12.72	$94.68
2017		46.29	33.26	13.03	$97.05
2018		47.53	34.17	13.36	$99.48
2019		48.85	35.16	13.69	$101.96
2020		50.25	36.21	14.04	$104.51
2021		50.70	36.31	14.39	$107.12
2022		52.04	37.29	14.75	$109.80
2023		53.43	38.31	15.12	$112.55
2024		54.86	39.37	15.49	$115.36
2025		56.42	40.54	15.88	$118.25
2006	**1 year -**				
|	Sum of PV Costs @ 8.72%	30.79	28.31	2.48	$18.49
2006 - 2010	**5 year -**				
|	Sum of PV Costs @ 8.72%	172.31	135.46	36.85	$274.39
|	Annual Cost of R/E @ 22.42%	38.63	30.37		
|	Annual Cost of Capacity @ 22.42%			8.26	$61.52
2006 - 2015	**10 years -**				
|	Sum of PV Costs @ 8.72%	290.51	220.65	69.86	$520.11
|	Annual Cost of R/E @ 12.85%	37.33	28.35		
|	Annual Cost of Capacity @ 12.85%			8.98	$66.83
2006 - 2025	**20 years -**				
|	Sum of PV Costs @ 8.72%	442.35	329.60	112.75	$839.40
|	Annual Cost of R/E @ 8.26%	36.53	27.22		
|	Annual Cost of Capacity @ 8.26%			9.31	$69.33

Footnotes: Ore Filed (non approved) - AC Study (11.10.2003)
(B) Tab 5.1 (Energy:) `Marginal Generation Energy Costs'
(C) Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'
(D) Tab 4.1 (Capacity:) `Marginal Capacity Costs Based on Avoided Capacity Costs'

Table 6

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost of
Transmission Investment and Associated Expenses

Line	Item	$'s
1	Growth Related Investments - (2006 to 2010 in $000's)	$302,130
2		
3	System Growth MW's from 2006 to 2010	1,381 mW
4		
5	Marginal Investment (growth invest / mWh)	$218.78 / kW
6		
7	Annualized Investment x 8.33%	18.22 / kW
8	Admin. & General Factor x 1.92%	4.20
9	Annual O&M Expenses x 1.086%	2.38 / kW
10	Annualized Marginal Cost	$24.80 / kW
11		
12	Marginal Cost of Demand-Related Transmission	$12.85 / kW
13		
14	Marginal Cost of Energy-Related Transmission (Line 10 - Line 12)	$11.97 / kW
15	Marginal Cost of Energy-Related Transmission	$0.00175 / kWh
16	$11.97 / (8760 x 78.02% LF))	

Sources:
Tab 6.2 (Transm2:) `2006-2010 Forecasted Transmission'
Tab 6.1 (Transm1:) `Marginal Transmission Investment and O&M Expenses'

Table 7

PacifiCorp
Oregon Marginal Cost Study
Marginal Distribution & Billing Costs By Load Size
December 2006 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(D) Primary (pri)	(E) General Service - Schedule 28 0-50 kW (sec)	(F) 51-100 kW (sec)	(G) > 101kW (sec)	(H) Primary (pri)	(I) General Service - Schedule 30 0-300 kW (sec)	(J) 301+ kW (sec)	(K) Primary (pri)	(L) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(M) 1 - 4 MW (pri)	(N) > 4 MW (sec)	(O) > 4 MW (pri)	(P) Trans (trn)	(Q) Irrg Sch 41 (sec)
	Demand Related Costs ($/kW)																		
1	Poles		14.03	16.25	16.25	16.25	11.48	11.48	11.48	11.48	10.10	10.10	10.10	7.67	7.67	0.87	0.55	NA	34.25
2	Conductors		23.27	26.43	26.43	26.43	19.67	19.67	19.67	19.67	17.68	17.68	17.68	14.23	14.23	1.76	1.11	NA	51.68
3	Substation		10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	10.93	NA	10.93
4	Dist. O&M @ of Total Investment	28.89%	13.93	15.49	15.49	15.49	12.16	12.16	12.16	12.16	11.18	11.18	11.18	9.48	9.48	3.92	3.64	NA	27.98
5	Total $/ Feeder kW		$62.16	$69.10	$69.10	$69.10	$54.24	$54.24	$54.24	$54.24	$49.89	$49.89	$49.89	$42.31	$42.31	$17.48	$16.23	-	$124.84
6																			
7	Transformers		0.68	0.88	0.88	NA	0.88	0.88	0.88	NA	0.88	0.88	NA	0.88	NA	0.88	NA	NA	0.88
8	Dist. O&M @ of Total Investment	28.89%	0.20	0.25	0.25	NA	0.25	0.25	0.25	NA	0.25	0.25	NA	0.25	NA	0.25	NA	NA	0.25
9	Total $/ Transformer kW		$0.88	$1.13	$1.13	$0.00	$1.13	$1.13	$1.13	$0.00	$1.13	$1.13	$0.00	$1.13	$0.00	$1.13	$0.00	$0.00	$1.13
10																			
11																			
12	Commitment Related Costs ($/Customer)																		
13	Poles		66.42	84.18	84.18	84.18	46.21	46.21	46.21	46.21	35.01	35.01	35.01	15.63	15.63	-	-	NA	225.87
14	Conductors		26.62	33.74	33.74	33.74	18.52	18.52	18.52	18.52	14.03	14.03	14.03	6.26	6.26	-	-	NA	90.53
15	Transformers		50.73	81.05	108.35	NA	168.79	182.16	195.67	NA	253.33	254.51	NA	430.12	NA	430.12	NA	NA	237.26
16	Dist. O&M @ of Total Investment	28.89%	41.54	57.48	65.37	34.07	67.46	71.33	75.23	18.70	87.35	87.70	14.17	130.59	6.32	124.26	-	NA	159.95
17	Total Commitment Related		$185.31	$256.45	$291.64	$151.99	$300.98	$318.22	$335.63	$83.43	$389.72	$391.25	$63.21	$582.60	$28.21	$554.38	$0.00	$0.00	$713.61
18																			
19	Billing Related Costs ($/Customer/Yr)																		
20	Service Drop		43.87	56.84	135.75	NA	141.57	146.56	311.12	NA	310.56	310.28	NA	604.58	NA	604.58	NA	NA	NA
21	Service Drop O&M @	28.89%	12.67	16.42	39.22	NA	40.90	42.34	89.88	NA	89.72	89.64	NA	174.66	NA	174.66	NA	NA	NA
22	Meter		10.42	11.51	24.66	$816.40	25.36	25.97	135.32	816.40	136.10	136.47	816.40	176.25	816.40	176.25	816.40	16,740.00	25.53
23	Meter O&M at	37.89%	3.95	4.36	9.34	309.33	9.61	9.84	51.27	309.33	51.57	51.71	309.33	66.78	309.33	66.78	309.33	6,342.79	9.67
24	Meter Reading		10.44	14.71	14.71	14.71	23.48	23.48	23.48	23.48	$23.48	$23.48	$23.48	31.20	31.20	31.20	31.20	31.20	28.18
25	Billing & Collections		21.72	20.45	20.45	20.45	50.90	50.90	50.90	50.90	$50.90	$50.90	$50.90	783.50	783.50	783.50	783.50	783.50	71.40
26	Uncollectables		13.09	2.29	2.29	2.29	24.43	24.43	24.43	24.43	$130.14	$130.14	$130.14	707.44	707.44	707.44	707.44	707.44	17.28
27	Customer Service / Other		$15.60	$13.67	13.67	13.67	$28.90	28.90	28.90	28.90	$55.15	$55.15	$55.15	382.25	382.25	382.25	382.25	382.25	33.38
28	Total Billing Related		$131.75	$140.26	$260.10	$1,176.86	$345.16	$352.43	$715.31	$1,253.45	$847.62	$847.77	$1,385.40	$2,926.66	$3,030.12	$2,926.66	$3,030.12	$24,987.18	$185.44
29																			
30																			
31	Monthly Billing Related (Line 28 / 12)		$10.98	$11.69	$21.67	$98.07	$28.76	$29.37	$59.61	$104.45	$70.64	$70.65	$115.45	$243.89	$252.51	$243.89	$252.51	$2,082.26	$15.45
32																			
33	Total Distribution (Comm & Billing Costs)		$317.06	$396.71	$551.74	$1,328.85	$646.14	$670.65	$1,050.94	$1,336.88	$1,237.34	$1,239.02	$1,448.61	$3,509.26	$3,058.33	$3,481.04	$3,030.12	$24,987.18	$899.05
34	Line 17 + Line 28																		
35	Monthly Commitment & Bill (Line 33 / 12)		$26.42	$33.06	$45.98	$110.74	$53.85	$55.89	$87.58	$111.41	$103.11	$103.25	$120.72	$292.44	$254.86	$290.09	$252.51	$2,082.26	$74.92

Sources: Lines
Line 1 - 2 Tab 8.1 (PC 1:) `Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 3 Tab 7.1 (Dist Sub 1:) `Distribution Substation Costs / kW'
Line 4 Sum of lines 1 to 3 multiplied by 28.89%
Tab 10.1 (Dist OM:) `Distribution O&M Expense Loading Factor as a Percent of Dist. Plant' (for 28.89% Factor)
Line 7 Tab 9.2 (XFMR 2:) `Transformer Demand Costs'
Line 13 - 14 Tab 8.1 (PC 1:) `Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 15 #VALUE!
Line 20 Tab 12.1 (Services 1:) `Weighted Average Installed Service Drop Costs'
Line 22 Tab 11.1 (Meters 1:) `Weighted Average Installed Meter Costs'
Line 23 Tab 11.5 (Meters 5:) `Distribution Meters Expense Loading Factor' (for 37.89% Factor)
Line 24 -27 Tab 13.1 (Cust Exp Sum:) `Summary of Customer Accounting Expense By Schedule'

Billing Costs

PacifiCorp
Oregon Marginal Cost Study
Total 20 Year Demand Costs Divided by Billing kW
December 2006 Dollars
(Dollars in 000's)

Line	Description	(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) Primary (pri)	(F) General Power - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) General Service - Schedule 30 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) 1 - 4 M (pri)	(O) > 4 MW (sec)	(P) > 4 M (pri)	(Q) Trans (trn)	(R) Irrg Sch 41 (sec)
	Demand Related Marginal Cost																		
1	Generation -	$158,489	$64,343	$9,251	$5,925	$10	$7,387	$7,149	$10,276	$249	$3,216	$12,932	$1,068	$9,414	$4,711	$819	$13,927	$5,212	$2,600
2	Transmission -	$29,376	$11,926	$1,715	$1,098	$2	$1,369	$1,325	$1,905	$46	$596	$2,397	$198	$1,745	$873	$152	$2,581	$966	$482
3																			
4	Distribution -																		
5	Poles, Wire, Sub	$133,303	$65,095	$9,037	$7,138	$11	$6,273	$6,397	$8,584	$209	$2,497	$9,968	$824	$6,140	$3,007	$206	$3,235	$0	$4,681
6	Transformers	$3,097	$1,900	$282	$107	$0	$214	$156	$195	$0	$0	$0	$0	$168	$0	$13	$0	$0	$63
7	Distribution Subtotal	$136,400	$66,995	$9,320	$7,245	$11	$6,487	$6,553	$8,779	$209	$2,497	$9,968	$824	$6,308	$3,007	$219	$3,235	$0	$4,744
8																			
9	Total Demand Related	$324,265	$143,264	$20,286	$14,268	$23	$15,243	$15,027	$20,960	$504	$6,309	$25,297	$2,090	$17,467	$8,591	$1,190	$19,743	$6,178	$7,826
10																			
11	Average Billing kW	4,933,294	2,942,127	323,380	122,591	247	223,381	161,923	202,393	5,163	64,721	248,252	21,204	175,013	71,618	16,728	241,438	113,115	65,115
12																			
13	Generation -		$21.87	$28.61	$48.33	$40.49	$33.07	$44.15	$50.77	$48.23	$49.69	$52.09	$50.37	53.79	65.78	48.96	57.68	46.08	39.93
14	Transmission -		$4.05	$5.30	$8.96	$8.10	$6.13	$8.18	$9.41	$8.91	$9.21	$9.66	$9.34	9.97	12.19	9.09	10.69	8.54	7.40
15																			
16	Distribution -																		
17	Poles, Wire, Sub		$22.13	$27.95	$58.23	$45.61	$28.08	$39.51	$42.41	$40.51	$38.57	$40.15	$38.88	35.08	41.98	12.33	13.40	0.00	71.89
18	Transformers		$0.65	$0.87	$0.87	$0.00	$0.96	$0.96	$0.96	$0.00	$0.00	$0.00	$0.00	0.96	0.00	0.77	0.00	0.00	0.97
19	Distribution subtotal		$22.77	$28.82	$59.10	$45.61	$29.04	$40.47	$43.37	$40.51	$38.57	$40.15	$38.88	36.04	41.98	13.10	13.40	0.00	72.86
20																			
21																			
22																			
23																			
24	Total Demand Related		$48.69	$62.73	$116.39	$94.20	$68.24	$92.80	$103.56	$97.65	$97.47	$101.90	$98.58	$99.80	$119.95	$71.15	$81.77	$54.62	$120.19
25																			
26	Monthly Demand Costs		$4.06	$5.23	$9.70	$7.85	$5.69	$7.73	$8.63	$8.14	$8.12	$8.49	$8.22	$8.32	$10.00	$5.93	$6.81	$4.55	$10.02

Full MC %

PacifiCorp
Oregon Marginal Cost Study
Marginal Cost Percentage @ Meter
December 2006 Dollars

Line	Description	(A) Marginal Cost (000)s	(B) Mills / kWh	(C) % of Total
	Demand Related Marginal Cost -			
1	Generation	$158,489	11.89	16.9%
2	Transmission	29,376	2.20	3.1%
3	Dist. Poles, Cond., Subst.	133,303	10.00	14.2%
4	Dist. Transformers	3,097	0.23	0.3%
5	Total Demand Related	$324,265	24.32	34.5%
6				
7	Energy Related Marginal Cost -			
8				
9	Generation	$397,192	29.79	42.2%
10	Transmission	25,555	1.92	2.7%
11	Total Energy Related	$422,747	31.71	45.0%
12				
13	Commitment & Billing -			
14	Commitment	115,677	8.68	12.3%
15	Billing	77,649	5.82	8.3%
16	Total Commitment & Billing	$193,326	14.50	20.6%
17				
18				
19	TOTAL MARGINAL COST	$940,338	70.53	100.0%
20				
21				
22	Note: Total MWh =	13,331,083		

PacifiCorp
Oregon Marginal Cost Study
10 Year Run Costing Inputs and Customer Data
Marginal Unit Costs
December 2006 Dollars

Line	Description		(A) Residential (sec)	(B) General Service - Schedule 23 0-15 kW (sec)	(C) 15+ kW (sec)	(E) (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) General Service - Schedule 30 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) 1 - 4 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) (trn)	(R) Irrg Sch 41 (sec)
	Billing Units																		
	Demand																		
1	Load Factors	System	68.69%	63.78%	63.54%	63.61%	68.64%	73.34%	76.39%	75.96%	70.45%	72.72%	72.48%	75.94%	79.79%	88.09%	86.79%	97.50%	69.16%
2		Feeder	60.88%	65.07%	52.58%	55.66%	63.23%	64.11%	71.53%	70.56%	65.31%	67.89%	67.61%	71.07%	76.29%	88.21%	87.47%	107.58%	69.16%
3		Transformer	29.41%	34.20%	57.56%	33.65%	38.67%	55.16%	66.08%	49.42%	59.65%	64.54%	49.27%	69.60%	56.60%	91.97%	67.54%	61.98%	47.05%
4	Peak MW @ Generator	System	928	133	85	0	107	103	148	4	46	187	15	136	68	12	201	75	38
5		Feeder	1,047	131	103	0	116	118	158	4	50	200	17	145	71	12	199	-	38
6		Transformer	2,167	249	94	N/A	189	137	171	6	55	210	23	148	N/A	11	N/A	N/A	55
7																			
8																			
9	Energy																		
10	Energy - Annual Mwh	@ Meter	5,079,177	678,078	432,675	728	582,614	602,504	902,113	22,353	260,390	1,080,762	91,525	821,613	444,269	82,940	1,428,559	614,130	206,654
11	Energy Loss Factor		1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0691	1.0995	1.0691	1.0995	1.0691	1.0454	1.0995
12	Energy - Annual Mwh	@ Generator	5,584,555	745,546	475,727	778	640,584	662,453	991,873	23,897	286,298	1,188,298	97,847	903,364	474,959	91,192	1,527,244	642,030	227,216
13																			
14																			
15	Customer																		
16	Annual Customers		460,491	63,230	5,457	29	4,643	3,099	2,006	54	312	646	56	138	56	3	35	1	8,338
17	Average Customers																		3,530
18																			
19	Unit Costs																		
20																			
21	Generation	$ / System Peak kW	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83	$66.83
22	Transmission	$ / System Peak kW	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85	$12.85
23	Poles, Cond., Subst.	$ / Feeder kW	$62.16	$69.10	$69.10	$69.10	$54.24	$54.24	$54.24	$54.24	$49.89	$49.89	$49.89	$42.31	$42.31	$17.48	$16.23	$0.00	$124.84
24	Transformers	$ / Xfmr kW	$0.88	$1.13	$1.13	$0.00	$1.13	$1.13	$1.13	$0.00	$1.13	$1.13	$0.00	$1.13	$0.00	$1.13	$0.00	$0.00	$1.13
25																			
26																			
27	Energy @ Generator	$ / Kwh	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010	$0.03010
28																			
29																			
30	Commitment & Billing	$ / Cust. / Year	$317.06	$396.71	$551.74	1,328.85	$646.14	$670.65	$1,050.94	$1,336.88	$1,237.34	$1,239.02	$1,448.61	3,509.26	$3,058.33	$3,481.04	$3,030.12	$24,987.18	899.05

PPL/1701
Anderberg/11

PacifiCorp
Oregon Marginal Cost Study
10 Year Marginal Cost By Load Class
December 2006 Dollars
(Dollars in 000's)

Line		(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) 1 - 4 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) (tm)	(R) Irrg Sch 41 (sec)
	Demand Related Marginal Cost																		
1	Generation -	$152,775	$62,023	$8,918	$5,712	$9	$7,120	$6,891	$9,905	$240	$3,100	$12,466	$1,030	$9,075	$4,541	$790	$13,425	$5,024	$2,506
2	Transmission -	$29,376	$11,926	$1,715	$1,098	$2	$1,369	$1,325	$1,905	$46	$596	$2,397	$198	$1,745	$873	$152	$2,581	$966	$482
3																			
4	Distribution -																		
5	Poles, Conductor, Substations	$133,302	$65,092	$9,038	$7,137	$11	$6,273	$6,398	$8,585	$210	$2,497	$9,968	$824	$6,139	$3,007	$206	$3,235	$0	$4,682
6	Transformers	$3,399	$1,907	$281	$107	$0	$214	$155	$194	$0	$62	$237	$0	$167	$0	$13	$0	$0	$62
7	Distribution subtotal	$136,701	$66,999	$9,319	$7,244	$11	$6,487	$6,553	$8,779	$210	$2,559	$10,205	$824	$6,306	$3,007	$219	$3,235	$0	$4,744
8																			
9	Total Demand Related	$318,852	$140,948	$19,952	$14,054	$22	$14,976	$14,769	$20,589	$496	$6,255	$25,068	$2,052	$17,126	$8,421	$1,161	$19,241	$5,990	$7,732
10	(Lines 1+2+7)																		
11																			
12																			
13	Energy Related Marginal Cost																		
14																			
15	Total Energy Related	$438,392	$168,103	$22,442	$14,320	$23	$19,282	$19,941	$29,857	$719	$8,618	$35,769	$2,945	$27,192	$14,297	$2,745	$45,972	$19,326	$6,840
16																			
17																			
18	Customer Related Marginal Cost																		
19																			
20	Commitment & Billing Rel.	$190,232	$146,004	$25,084	$3,011	$39	$3,000	$2,078	$2,108	$72	$386	$800	$81	$484	$171	$10	$106	$25	$6,773
21																			
22																			
23	Total Revenue @ Full MC	$947,476	$455,055	$67,478	$31,385	$84	$37,258	$36,788	$52,554	$1,287	$15,259	$61,637	$5,078	$44,802	$22,889	$3,916	$65,319	$25,341	$21,345

PacifiCorp
Oregon Marginal Cost Study
5 Year Marginal Costs by Load Class
December 2006 Dollars
(Dollars in 000's)

Line		(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) 1 - 4 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) (trn)	(R) Irrg Sch 41 (sec)
	Billing Units																		
	Demand																		
1	Load Factors	System	68.69%	63.78%	63.54%	63.61%	68.64%	73.34%	76.39%	75.96%	70.45%	72.72%	72.48%	75.94%	79.79%	88.09%	86.79%	97.50%	69.16%
2	Peak MW @ Generator	System	928	133	85	0	107	103	148	4	46	187	15	136	68	12	201	75	38
3																			
4	Energy																		
5	Energy - Annual Mwh @ Meter	13,124,429	5,079,177	678,078	432,675	728	582,614	602,504	902,113	22,353	260,390	1,080,762	91,525	821,613	444,269	82,940	1,428,559	614,130	206,654
6	Energy Loss Factor		1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0691	1.0995	1.0691	1.0995	1.0691	1.0454	1.0995
7	Energy - Annual Mwh @ Generator	14,336,646	5,584,555	745,546	475,727	778	640,584	662,453	991,873	23,897	286,298	1,188,298	97,847	903,364	474,959	91,192	1,527,244	642,030	227,216
8																			
9	Customer																		
10	Average Customers	540,256	460,491	63,230	5,457	29	4,643	3,099	2,006	54	312	646	56	138	56	3	35	1	8,338
11																			3,530
12	Unit Costs																		
13																			
14	Generation - $ / System Peak Kw		$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52	$61.52
15	Energy @ Generator $ / Kwh		$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037	$0.03037
16	Billing Related Costs		$131.75	$140.26	$260.10	$1,176.86	$345.16	352.43	$715.31	$1,253.45	$847.62	$847.77	$1,385.40	$2,926.66	$3,030.12	$2,926.66	$3,030.12	$24,987.18	$35.20
17																			$150.24
18	Marginal Costs $000																		
19																			
20	Total Demand Related	$138,328	$57,095	$8,209	$5,258	$9	$6,555	$6,343	$9,118	$221	$2,854	$11,475	$948	$8,354	$4,180	$727	$12,358	$4,625	$2,307
21																			
22	Total Energy Related	$435,406	$169,603	$22,642	$14,448	$24	$19,455	$20,119	$30,123	$726	$8,695	$36,089	$2,972	$27,435	$14,425	$2,770	$46,382	$19,498	$6,901
23																			
24	Billing Related Costs	$76,795	$60,671	$8,869	$1,419	$34	$1,603	$1,092	$1,435	$68	$264	$548	$78	$404	$170	$9	$106	$25	$824
25																			
26	Total Revenue @ Full MC	$650,529	$287,369	$39,720	$21,125	$67	$27,613	$27,554	$40,676	$1,015	$11,813	$48,112	$3,998	$36,193	$18,775	$3,506	$58,846	$24,148	$10,032

PacifiCorp
Oregon Marginal Cost Study
1 Year Marginal Costs by Load Class
December 2006 Dollars
(Dollars in 000's)

Line		(A) Total	(B) Residential (sec)	(C) General Service - Schedule 23 0-15 kW (sec)	(D) 15+ kW (sec)	(E) (pri)	(F) General Service - Schedule 28 0-50 kW (sec)	(G) 51-100 kW (sec)	(H) > 101kW (sec)	(I) Primary (pri)	(J) 0-300 kW (sec)	(K) 301+ kW (sec)	(L) Primary (pri)	(M) Large Power Service - Schedule 48T 1 - 4 MW (sec)	(N) 1 - 4 MW (pri)	(O) > 4 MW (sec)	(P) > 4 MW (pri)	(Q) (trn)	(R) Irrg Sch 41 (sec)
	Billing Units																		
	Energy																		
1	Energy - Annual Mwh @ Meter	13,331,083	5,079,177	678,078	432,675	728	582,614	602,504	902,113	22,353	260,390	1,080,762	91,525	821,613	444,269	82,940	1,428,559	614,130	206,654
2	Energy Loss Factor		1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0995	1.0691	1.0995	1.0995	1.0691	1.0995	1.0691	1.0995	1.0691	1.0454	1.0995
3	Energy - Annual Mwh @ Generator	14,563,862	5,584,555	745,546	475,727	778	640,584	662,453	991,873	23,897	286,298	1,188,298	97,847	903,364	474,959	91,192	1,527,244	642,030	227,216
4																			
5	Customer																		
6	Average Customers	548,594	460,491	63,230	5,457	29	4,643	3,099	2,006	54	312	646	56	138	56	3	35	1	8,338
7																			3,530
8	Unit Costs																		
9																			
10	Energy @ Generator $ / Kwh		$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831	$0.02831
11																			
12	Billing Related Costs		$131.75	$140.26	$260.10	1,176.86	$345.16	352.43	$715.31	$1,253.45	$847.62	$847.77	$1,385.40	$2,926.66	$3,030.12	$2,926.66	$3,030.12	$24,987.18	$35.20
13																			$150.24
14																			
15	Marginal Costs $000																		
16																			
17	Total Energy Related	$412,303	$158,099	$21,106	$13,468	$22	$18,135	$18,754	$28,080	$677	$8,105	$33,641	$2,770	$25,574	$13,446	$2,582	$43,236	$18,176	$6,432
18																			
19	Billing Related Costs	$77,619	$60,671	$8,869	$1,419	$34	$1,603	$1,092	$1,435	$68	$264	$548	$78	$404	$170	$9	$106	$25	$824
20																			
21																			
22	Total Revenue @ Full MC	$489,922	$218,770	$29,975	$14,887	$56	$19,738	$19,846	$29,515	$745	$8,369	$34,189	$2,848	$25,978	$13,616	$2,591	$43,342	$18,201	$7,256

Streetlight 1

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Commitment & Billing Related Cost per Customer

Line	Description	Schedule 51 Wood Pole Installations Company Owned				Schedule 53	Schedule 54
						Customer Owned	
		70 Watt HPSV	100 Watt HPSV	200 Watt HPSV	400 Watt HPSV		
1	Light Installation Cost - per lamp	$116.39	$120.43	$128.64	$176.11	N. A.	N. A.
2							
3	Distribution Commitment Costs - per customer						
4	Acct. 364 Poles	$84.18	84.18	84.18	84.18	$84.18	$84.18
5	Acct. 365 Conductors	$33.74	$33.74	$33.74	$33.74	$33.74	$33.74
6	Acct. 368 Transformers	N. A.	N. A.	N. A.	N. A.	81.05	108.35
7	Dist O&M at 28.9% of Total Investment	$34.07	$34.07	$34.07	$34.07	$57.48	$65.37
8	Acct. 370 Meters						$11.51
9	Meters at 37.89% of Total Investment	$0.00	$0.00	$0.00	$0.00	$0.00	$4.36
10	Total Commitment Related	$151.99	$151.99	$151.99	$151.99	$256.46	$307.51
11							
12	Billing Costs per Customer	$28.78	$28.78	$28.78	$28.78	$28.78	$43.49
13							
14	Total Marginal Commitment & Billing Cost per Cust.	$180.76	$180.76	$180.76	$180.76	$285.23	$351.01

Sources:
Line 1 "Distribution Cost Development For Street Lighting"
Line 4 `Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 5 `Hypothetical Feeder Study Results Annual Demand and Commitment Costs'
Line 6 `Transformer Commitment Costs By Customer Load Class'
Line 7 Sum of lines 4 to 6 multiplied by 28.9%
`Distribution O&M Expense Loading Factor as a Percent of Dist. Plant'
Line 14 Sum of Commitment & Billing Costs per Customer

Streetlight 2

PacifiCorp
Oregon Marginal Cost Study
Street Light and Recreational Lighting
Full Marginal Cost by Schedule

Line	Description	Units	Schedule 51 Company Owned - Wood Pole Installations: 70 Watt 5800 Lumens HPSV	100 Watt 9500 Lumens HPSV	200 Watt 22,000 Lumens HPSV	400 Watt 50,000 Lumens HPSV	Schedule 53 Customer Owned	Schedule 54 Customer Owned	Total Streetlighting
	Energy								
1	Generation Energy $/kWh @ Generator	$/kWh	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	$0.02722	
2	Transmission Energy $/kWh @ Generator	$/kWh	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	$0.00175	
3			ok						
4	Energy @ Meter FY04	kWh	1,559,519	5,060,139	5,540,413	2,172,236	7,735,387	851,281	
5	Energy @ Meter CY06		1,778,971	5,772,191	6,320,048	2,477,908	8,399,592	760,384	
6	Losses		1.09950	1.09950	1.09950	1.09950	1.09950	1.09950	
7	Energy @ Generator - (5)*(6)	kWh	1,955,979	6,346,524	6,948,893	2,724,460	9,235,351	836,042	28,047,249
8									
9	Generation Energy Related Marginal Costs - (1)*(7)	$	$53,242	$172,752	$189,149	$74,160	$251,386	$22,757	$763,446
10	Transmission Energy Related Marginal Costs - (2)*(7)	$	$3,426	$11,115	$12,170	$4,771	$16,174	$1,464	$49,120
11									
12	Commitment								
13	Number of Lamps FY04	#	4,192	9,584	5,432	1,029			
14	Escalation factor		1.141	1.141	1.141	1.141			
15	Number of Lamps 12/06		4,782	10,932	6,196	1,173			
16	Light Installation Cost	$/Lamp	$116.39	$120.43	$128.64	$176.11			
17	Light Installation Related		$556,602	$1,316,541	$797,074	$206,620			$2,876,837
18			ok						
19	Average customers - 12/06	#	125	299	187	56	229	91	987
20									
21									
22	Acct. 364 Poles		$84.18	$84.18	$84.18	$84.18	$84.18	$84.18	
23	Acct. 365 Conductors		$33.74	$33.74	$33.74	$33.74	$33.74	$33.74	
24	Acct. 368 Transformers		N. A.	N. A.	N. A.	N. A.	$81.05	$108.35	
25	Acct. 370 Meters							$11.51	
26									
27	Acct. 364 Poles with O&M		$13,562	$32,441	$20,289	$6,076	$24,846	$9,873	$107,089
28	Acct. 365 Conductors with O&M		$5,436	$13,003	$8,132	$2,435	$9,959	$3,957	$42,922
29	Acct. 368 Transformers with O&M		N.A.	N.A.	N.A.	N.A.	$23,923	$12,709	$36,632
30	Acct. 370 Meter with O&M		N.A.	N.A.	N.A.	N.A.	N.A.	$1,444	$1,444
31	Total Poles, Conductors, Transfomers		$18,998	$45,444	$28,422	$8,511	$58,728	$27,984	$188,088
32									
33	Total Commitment Marginal Cost		$575,600	$1,361,986	$825,495	$215,131	$58,728	$27,984	$3,064,925
34									
35	Billing / Customer								
36	Billing Related	$/Customer	$19.55	$19.55	$19.55	$19.55	$19.55	$19.55	
37	Meter Reading	$/Customer	-	-	-	-	-	$14.71	
38	Customer Other	$/Customer	$9.23	$9.23	$9.23	$9.23	$9.23	$9.23	
39									
40	Billing Related	$	2,444	5,846	3,656	1,095	4,477	1,779	$19,298
41	Meter Reading	$	-	-	-	-	-	1,339	$1,339
42	Customer Other	$	1,153	2,759	1,725	517	2,113	840	$9,106
43	Total Billing Related Marginal Cost		$3,597	$8,605	$5,381	$1,612	$6,590	$3,958	$29,743
44									
45	Total Marginal Cost		$635,865	$1,554,457	$1,032,196	$295,674	$332,879	$56,163	$3,907,234
									$3,094,668

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$489,303	$251,386	$22,757	$763,446
Transmission	$31,482	$16,174	$1,464	$49,120
Distribution	$2,978,213	$58,728	$27,984	$3,064,925
Customer - Billing	$13,041	4,477	1,779	$19,298
Customer - Metering	-		1,339	$1,339
Customer - Other	6,154	2,113	840	$9,106
	$3,518,192	$332,879	$56,163	$3,907,234

Input to Exhibits

	Sch. 51	Sch. 53	Sch. 54	Total
Generation	$489.30	$251.39	$22.76	$763.45
Transmission	$31.48	$16.17	$1.46	$49.12
Distribution	$2,978.21	$58.73	$27.98	$3,064.92
Customer - Billing	$13.04	$4.48	$1.78	$19.30
Customer - Metering	$0.00	$0.00	$1.34	$1.34
Customer - Other	$6.15	$2.11	$0.84	$9.11

PPL/1701
Anderberg/16

Streetlight 3

PacifiCorp
Oregon Marginal Cost Study
Distribution Cost Development
For Street Lighting Service
Fully-Loaded Overheads
Schedule 51

Line No.	Description		Wood Pole Installations			
			70 Watt HPSV	100 Watt HPSV	200 Watt HPSV	400 Watt HPSV
	Installed Costs					
1	Cost per unit including pole, luminaire, p.e.	FY/04 $	773.00	798.00	858.60	1,174.50
2	Index		1.0612	1.0612	1.0612	1.0612
3	Control, mast arm and wiring	CY/06 $	820.34	846.87	911.18	1,246.42
4	Transformer Cost	FY/04 $	6.57	9.26	18.05	37.30
5	Index		1.0193	1.0193	1.0193	1.0193
6	Revised Transformer Cost	CY/06 $	6.70	9.44	18.40	38.02
7	Total Installed Cost		827.04	856.31	929.58	1,284.44
8						
9						
10	Annual Cost @	10.80%	$89.32	$92.48	$100.39	$138.72
11						
12	*Operation & Maintenance*					
13	Annual Main. Per Unit		$27.07	$27.95	$28.25	$37.39
14						
15	TOTAL COST PER UNIT		$116.39	$120.43	$128.64	$176.11
16						
17	Total Number of Units		4,192	9,584	5,432	1,029
18						
19	Annual Maintenance Per Unit					
20	Percentage of Installed Cost		3.30%	3.30%	3.10%	3.00%
21	Installed Cost		820.34	846.87	911.18	1,246.42
22	Annual Maintenance Per Unit		$27.07	$27.95	$28.25	$37.39
23						
24	Installed Cost					
25	With Pole		$1,088.00	$1,113.00	$1,161.00	$1,508.00
26	Without Pole		$710.00	$735.00	$783.00	$841.00
27	Difference (Wood Pole Cost)		$378.00	$378.00	$378.00	$667.00
28	Percent of Wood Pole Utilized		$0.17	$0.17	$0.20	$0.50
29	Adjusted Wood Pole Cost		$63.00	$63.00	$75.60	$333.50
30	Installed Cost for Analysis		$773.00	$798.00	$858.60	$1,174.50
31						
32	Assumptions: Based on study done by Tom Yousko dated 1/1996					
33	Annual Maintenance Per Unit - Percentage of installed cost from 11/99 study.					
34	70 Watt It is assumed, one new wood pole is to be installed per six new lights, therefore, 1/6 X unit cost of wood pole w					
35	100 Watt It is assumed, one new wood pole is to be installed per six new lights, therefore, 1/6 X unit cost of wood pole \					
36	200 Watt It is assumed, one new wood pole is to be installed per five new lights, therefore, 1/5 X unit cost of wood pole					
37	200 Watt It is assumed, one new wood pole is to be installed per two new lights, therefore, 1/2 X unit cost of wood pole					

Streetlight 4

PacifiCorp
Oregon Marginal Cost Study
Cost of Streetlighting Transformer

Transformer Cost Per Light - 70 Watt H.P.S.V.

Assume Installed Cost 25 KVA Transformer is $ 1,833

Lamp Line Watts		=	83 watts
+ Ballast (Encasement) Loss	3.0%		2.49
+ Circuit Loss	5.0%		4.15
			89.64

Transformer Cost = Total Watts/25,000 X Installed Cost
89,6/25000 X $1508 = $ 6.57

Transformer Cost Per Light - 100 Watt H.P.S.V.

Assume Installed Cost 25 KVA Transformer is $ 1,833

Lamp Line Watts		=	117 watts
+ Ballast (Encasement) Loss	3.0%		3.51
+ Circuit Loss	5.0%		5.85
			126.36

Transformer Cost = Total Watts/25,000 X Installed Cost
126.36/25000 X $15(= $ 9.26

Source:
Study by Tom Yousko 11/96

Transformer Cost Per Light - 200 Watt H.P.S.V.

Assume Installed Cost 25 KVA Transformer is $ 1,833

Lamp Line Watts		=	228 watts
+ Ballast (Encasement) Loss	3.0%		6.84
+ Circuit Loss	5.0%		11.4
			246.24

Transformer Cost = Total Watts/25,000 X Installed Cost
246.24/25000 X $150 = $ 18.05

Transformer Cost Per Light - 400 Watt H.P.S.V.

Assume Installed Cost 25 KVA Transformer is $ 1,833

Lamp Line Watts		=	471 watts
+ Ballast (Encasement) Loss	3.0%		14.13
+ Circuit Loss	5.0%		23.55
			508.68

Transformer Cost = Total Watts/25,000 X Installed Cost
508.68/25000 X $150 = $ 37.30

Capacity

PacifiCorp
Oregon Marginal Cost Study
Marginal Capacity Costs
Based on Avoided Capacity Costs

Calendar Year (12 Mo Ended Dec)	(A) Projected Capacity $/kW	(B) Present Value Factors @ 8.72%	(C) PV of Capacity $/kW (A) x (B)	(D) Capacity Mills/kWh (A) / 0.85 / 8760	(E) PV of Capacity Mills/kWh (B) * (D)
2006	$18.49	1.0000	18.49	2.48	2.48
2007	$75.81	0.9198	69.73	10.18	9.36
2008	$77.71	0.8460	65.74	10.44	8.83
2009	$79.65	0.7782	61.99	10.70	8.33
2010	$81.64	0.7158	58.44	10.96	7.85
2011	$83.69	0.6584	55.10	11.24	7.40
2012	$85.78	0.6056	51.95	11.52	6.98
2013	$87.92	0.5570	48.97	11.81	6.58
2014	$90.12	0.5123	46.17	12.10	6.20
2015	$92.37	0.4712	43.53	12.41	5.85
2016	$94.68	0.4334	41.04	12.72	5.51
2017	$97.05	0.3986	38.68	13.03	5.19
2018	$99.48	0.3666	36.47	13.36	4.90
2019	$101.96	0.3372	34.38	13.69	4.62
2020	$104.51	0.3102	32.42	14.04	4.36
2021	$107.12	0.2853	30.56	14.39	4.11
2022	$109.80	0.2624	28.81	14.75	3.87
2023	$112.55	0.2414	27.17	15.12	3.65
2024	$115.36	0.2220	25.61	15.49	3.44
2025	$118.25	0.2042	24.15	15.88	3.24

			$/kW	mills / kWh
2006	1 Year -	Sum of PV Costs @ 8.72%	18.49	2.48
2006 - 2010	5 Year -	Short Run -		
		Sum of PV Costs @ 8.72%	$274.39	$36.85
		Annual Cost of Capacity @ 22.42%	61.52	8.26
2006 - 2015	10 Years -	Medium Run -		
		Sum of PV Costs @ 8.72%	$520.11	69.86
		Annual Cost of Capacity @ 12.85%	66.83	8.98
2006 - 2025	20 Years -	Long Run -		
		Sum of PV Costs @ 8.72%	$839.40	112.75
		Annual Cost of Capacity @ 8.26%	69.33	9.31

Footnote: Column A: Ore Filed (non approved) - AC Study (11.10.2003)

Energy

PacifiCorp
Oregon Marginal Cost Study
Marginal Generation Energy Costs
Nominal Mills / kWh

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)	(K)	(L)	(M)	(N)
Calendar Year (12 Mo Ended Dec)	SCCT Fixed Costs ($/kW-yr) (1)	SCCT Fixed Costs ($/kW-mo) (2)	CCCT Fixed Costs ($/kW-yr) (3)	CCCT Fixed Costs ($/kW-mo) (4)	Capitalized Energy Cost ($/kW-mo) (4) - (2) = (5)	Capitalized Energy Cost 85% CF ($/MWh) (6)	Purchase Cost ($/MWh) (7)	Updated Gas Price ($/MMBtu) (8)	CCCT Energy Costs 7074 Btu/kWh ($/MWh) (9)	Variable Avoided Energy Cost ($/MWh) (7) + (9) =(10)	Capitalized Energy Cost 85% CF ($/MWh) (6)=(11)	Total Avoided Energy Cost ($/MWh) (10) + (11) =(12)	Present Value Factors (13) @ 8.72%	Present Value of Energy (14) (12)*(13)
2006	0.00	0.00	0.00	0.00	0.00	0.00	28.31	0.00	0.00	28.31	0.00	28.31	1.0000	28.31
2007	75.81	6.32	96.31	8.03	1.71	2.75	0.00	4.29	30.35	30.35	2.75	33.10	0.9198	30.44
2008	77.71	6.48	98.71	8.23	1.75	2.82	0.00	4.38	30.97	30.97	2.82	33.79	0.8460	28.59
2009	79.65	6.64	101.18	8.43	1.79	2.89	0.00	4.29	30.38	30.38	2.89	33.27	0.7782	25.89
2010	81.64	6.80	103.71	8.64	1.84	2.96	0.00	3.97	28.08	28.08	2.96	31.05	0.7158	22.22
2011	83.69	6.97	106.30	8.86	1.88	3.04	0.00	3.82	27.02	27.02	3.04	30.06	0.6584	19.79
2012	85.78	7.15	108.96	9.08	1.93	3.11	0.00	3.94	27.88	27.88	3.11	31.00	0.6056	18.77
2013	87.92	7.33	111.68	9.31	1.98	3.19	0.00	4.06	28.75	28.75	3.19	31.94	0.5570	17.79
2014	90.12	7.51	114.48	9.54	2.03	3.27	0.00	3.64	25.74	25.74	3.27	29.01	0.5123	14.86
2015	92.37	7.70	117.34	9.78	2.08	3.35	0.00	3.72	26.31	26.31	3.35	29.66	0.4712	13.98
2016	94.68	7.89	120.27	10.02	2.13	3.44	0.00	3.97	28.10	28.10	3.44	31.53	0.4334	13.67
2017	97.05	8.09	123.28	10.27	2.19	3.52	0.00	4.20	29.73	29.73	3.52	33.26	0.3986	13.26
2018	99.48	8.29	126.36	10.53	2.24	3.61	0.00	4.32	30.56	30.56	3.61	34.17	0.3666	12.53
2019	101.96	8.50	129.52	10.79	2.30	3.70	0.00	4.45	31.46	31.46	3.70	35.16	0.3372	11.86
2020	104.51	8.71	132.76	11.06	2.35	3.79	0.00	4.58	32.42	32.42	3.79	36.21	0.3102	11.23
2021	107.12	8.93	136.08	11.34	2.41	3.89	0.00	4.58	32.42	32.42	3.89	36.31	0.2853	10.36
2022	109.80	9.15	139.48	11.62	2.47	3.99	0.00	4.71	33.30	33.30	3.99	37.29	0.2624	9.78
2023	112.55	9.38	142.97	11.91	2.53	4.09	0.00	4.84	34.23	34.23	4.09	38.31	0.2414	9.25
2024	115.36	9.61	146.54	12.21	2.60	4.19	0.00	4.97	35.18	35.18	4.19	39.37	0.2220	8.74
2025	118.25	9.85	150.20	12.52	2.66	4.29	0.00	5.12	36.25	36.25	4.29	40.54	0.2042	8.28

				Mills / kWh
2006	1 Year -	Sum of PV Costs		28.31
2006 - 2010	5 Year -	Short Run -		
		Sum of PV Costs	@ 8.72% =	135.46
		Annual Cost of Energy	@ 22.42% =	30.37
2006 - 2015	10 Years -	Medium Run -		
		Sum of PV Costs	@ 8.72% =	220.65
		Annual Cost of Energy	@ 12.85% =	28.35
2006 - 2025	20 Years -	Long Run -		
		Sum of PV Costs	@ 8.72% =	329.60
		Annual Cost of Energy	@ 8.26% =	27.22

Footnote: Column A: Ore Filed (non approved) - AC Study (11.10.2003)

PacifiCorp
Marginal Generation Costs
Filed

Calendar Year	12 Months Ended December		
	Avoided Firm Capcity Costs ($/kW-yr)	Combined Cycle CT Fixed Cost ($/kW-yr)	Gas Price ($/MMBtu)
2003	-	-	-
2004	-	-	-
2005	-	-	-
2006	18.49	-	-
2007	75.81	96.31	4.29
2008	77.71	98.71	4.38
2009	79.65	101.18	4.29
2010	81.64	103.71	3.97
2011	83.69	106.30	3.82
2012	85.78	108.96	3.94
2013	87.92	111.68	4.06
2014	90.12	114.48	3.64
2015	92.37	117.34	3.72
2016	94.68	120.27	3.97
2017	97.05	123.28	4.20
2018	99.48	126.36	4.32
2019	101.96	129.52	4.45
2020	104.51	132.76	4.58
2021	107.12	136.08	4.58
2022	109.80	139.48	4.71
2023	112.55	142.97	4.84
2024	115.36	146.54	4.97
2025	118.25	150.20	5.12

Source: Ore Filed (non approved) - AC Study (11.10.2003)

Transm1

PacifiCorp
Oregon Marginal Cost Study
Marginal Transmission Investment and O&M Expenses
December 2006 Dollars

Line	Item	(A) Total (B) + (C)	(B) Demand Related	(C) Energy Related	
1	2006 Forecasted	105,044	42,772	62,272	
2	2007 Forecasted	71,925	38,784	33,141	
3	2008 Forecasted	62,354	32,028	30,326	
4	2009 Forecasted	46,865	27,716	19,149	
5	2010 Forecasted	15,942	15,160	782	
6					
7	Growth Related Investments - (2006 to 2010 in $000's)	$302,130	$156,460	$145,670	
8					
9	System Growth mW's from 2006-2010	1,381	1,381	1,381	mW
10					
11	Marginal Investment (7) / (9)	$218.78	$113.29	$105.48	/kW
12					
13	Annualized Investment (11) x 8.33%	$18.22	$9.44	$8.79	/kW
14	Admin. & General Factor (11) x 1.92%	$4.20	$2.18	$2.03	/kW
15	Annual O&M Expenses (11) x 1.086%	$2.38	$1.23	$1.15	/kW
16					
17	Annualized Marginal Cost Sum (13) to (15)	$24.80	$12.85	$11.97	/kW
18					
19	Marginal Cost of Energy-Related Transmission			$0.00175	/kWh
20	$11.97 / 8760 hours / 78.02% Load Factor))				

Footnote:

Lines 1-7	Tab 6.2 (Transm2:) `2006-2010 Forecasted Transmission'
Line 9	Peak Load Forecast Detail, Oct. 11, 2004 (R. Davis)
Line 13	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 8.33% factor)
Line 14	Tab 15.1 (Charge 1:) `Calculation of Annual Charges' (for 1.92% factor)

Transm2

PacifiCorp
Oregon Marginal Cost Study
2006-2010 Forecasted Transmission
December 2006 Dollars(in 000's)

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				Forecast			Total
Line	Description	2006	2007	2008	2009	2010	
1	Bulk Power Lines (grid)	79,671	42,400	38,800	24,500	1,000	
2	price adjustment factor	1.049	1.049	1.049	1.049	1.049	
3	Adjusted Bulk Power Lines (grid)	83,575	44,478	40,701	25,700	1,049	195,503
4							
5	Growth Related Major Projects (local)	20,936	26,765	21,115	20,639	14,523	
6	price adjustment factor	1.025	1.025	1.025	1.025	1.025	
7	Adjusted Growth Related Major Projects (local)	21,469	27,447	21,653	21,165	14,893	106,627
8							
9	Bulk Power Lines - Demand Related	21,303	11,337	10,375	6,551	267	
10	Line (3) x Demand Factor 25.49%						
11							
12	Bulk Power Lines - Energy Related	62,272	33,141	30,326	19,149	782	145,670
13	Line (3) - Line (9)						
14							
15	Total Growth Demand Related	42,772	38,784	32,028	27,716	15,160	156,460
16	Line (7) + Line (9)						
17							
18	$ Demand Related	$42,772	$38,784	$32,028	$27,716	$15,160	$156,460
19	$ Energy Related	$62,272	$33,141	$30,326	$19,149	$782	$145,670
20							
21	Total Marginal Transmission Investment	$105,044	$71,925	$62,354	$46,865	$15,942	$302,130

Bulk Power Lines - Price Adjustment Factor	DRI Index: EOY 2006		
(Dollars based on CY2004)	2004	2005	2006
Pacific Region - (Trend 023)	422.70	433.30	444.90
Plateau Region - (Trend 023)	384.80	392.80	402.30
Average Pacific & Plateau	1.049	1.025	1.000

Growth Related Projects - Price Adjustment Factor	DRI Index: EOY 2006		
(Dollars based on CY2005)		2005	2006
Pacific Region - (Trend 023)		433.30	444.90
Plateau Region - (Trend 023)		392.80	402.30
Average Pacific & Plateau		1.025	1.000

Footnotes:

Line 3	Bulk power lines were based on CY2004 dollars; adjusted to CY2006
Line 7	Growth related projects were based on CY2005 dollars; adjusted to CY2006
Line 10	Demand Portion of Transmission = 9.31 / (9.31+27.22) = 25.49%

PPL/1701
Anderberg/23

Tran_OM

PacifiCorp
Transmission O & M Expenses
(Dollars in 000's)

Line	Description	(A) 1994	(B) 1995	(C) 1996	(D) 1997	(E) 1998	(F) 1999	(G) 2000	(H) 2001	(I) 2002	(J) 2003	
1	Transmission O&M Exp.	68,342	67,728	78,625	93,829	97,034	83,874	103,968	123,213	102,419	105,962	
2	Wheeling	46,315	45,054	56,372	70,519	74,244	71,336	78,405	94,737	76,949	77,497	
3	Net Transmission O&M Line (1) - (2)	22,027	22,673	22,253	23,310	22,789	12,538	25,563	28,476	25,469	28,465	
4	Transmission Plant	1,974,551	2,042,485	2,069,194	2,087,779	2,102,335	2,135,940	2,172,469	2,232,246	2,299,173	2,396,665	
5	Tran. O&M Loading Line (3) / (4)	1.116%	1.110%	1.075%	1.116%	1.084%	0.587%	1.177%	1.276%	1.108%	1.188%	1.086%

Notes:
FERC Form 1, December 31, 2003
Lines 1, 2 - page 321
Line 4 - page 207

PPL/1701
Anderberg/24

Dist Sub 1

PacifiCorp
Oregon Marginal Cost Study
Distribution Substation Costs / kW
December 2006 Dollars

Line		
1	Incremental Substation Cost - $ / kW	$101.20
2		
3	Annual Distribution Carrying Charge	10.80%
4		
5	Substation Marginal Cost - $ / kW	$10.93 / kW

Dist Sub 2

PacifiCorp
Marginal Cost Study
Substation Investment

In Service Date	Substation Capacity Project	State	Capacity Increase (MVA)	Installed Cost	Cost Per MVA
June-02	Angel Sub - Install 2nd 138-12.5 Xfm	UT	30.0	$2,330,000	$77,667
June-03	Alta View Sub - Increase XFM Capacity	UT	25.0	$1,896,000	$75,840
June-03	Magna Construct New 138-12.5 sub	UT	30.0	$2,950,000	$98,333
June-03	Mantua Sub - Increase XFM capacity	UT	1.3	$175,000	$134,615
October-03	Millville Sub - Increase XFM Capacity	ID	11.0	$674,000	$61,273
June-03	South Jordan Sub - Construct New 138-12.5	UT	30.0	$2,700,000	$90,000
June-03	Coldwater Canyon - Construct New 138-12.5	UT	30.0	$3,250,000	$108,333
June-03	Hammer Sub - Install 2nd 138-12.5 Xfm	UT	30.0	$2,770,000	$92,333
December-03	Sunrise Sub - Construct New 138-12.5 Sub	UT	30.0	$2,950,000	$98,333
November-04	Raymond Sub - Increase 69-12 Capacity	ID	3.0	$144,000	$48,000
November-04	Cross Hollow Sub - Construct 138-12.5 Sub	UT	22.4	$2,200,000	$98,214
October-04	Mary's River Sub - Increase Capacity	OR	12.5	$778,000	$62,240
January-04	Plain City Sub - Construct New 138-12.5	UT	30.0	$2,950,000	$98,333
June-04	South Mtn Sub - Install 2nd 138-12.5 XFM	UT	30.0	$1,800,000	$60,000
November-04	Shevlin Park - Construct New 69-12.5 Sub	OR	25.0	$2,200,000	$88,000
July-05	Roxy Ann Sub - Construct New 115-12.5 Sub	OR	25.0	$2,850,000	$114,000
June-05	Beall Lane Sub - Construct New 115-12.5 Sub	OR	25.0	$3,100,000	$124,000
September-05	Chapel Hill Sub - Construct New 138-12.5 Sub	UT	30.0	$3,900,000	$130,000
July-05	Carlisle Sub - Construct New 138-12.5 Sub	UT	30.0	$2,900,000	$96,667
July-05	Dimple Dell - Install 2nd 138-12.5 Xfm	UT	30.0	$2,400,000	$80,000
June-05	Bluffdale Sub - Increase 46-12.5 XFM Capacity	UT	4.5	$425,000	$94,444
June-05	North Logan - Increase 46-12 Capacity	UT	11.0	$1,400,000	$127,273
March-05	Newell Sub Increase 69-12 Capacity	OR	5.0	$575,000	$115,000
May-05	Touchet Sub - Increase 69-12 Capacity	WA	6.0	$634,000	$105,667
June-05	Gordon Ave - Construct 138-12.5 Sub	UT	30.0	$3,400,000	$113,333
June-05	Cherrywood Sub - Increase 138-12 Capacity	UT	30.0	$2,600,000	$86,667
September-05	70th South Sub - Construct New 138-12 Sub	UT	30.0	$3,800,000	$126,667
November-05	Bond St Sub - Construct New 69-12 Sub	OR	25.0	$2,300,000	$92,000
June-06	BDO - Construct New 138-12 Sub	UT	30.0	$3,900,000	$130,000
June-06	Lakeside Sub - Construct New 138-12 Sub	UT	30.0	$3,600,000	$120,000
June-06	152nd Sub - Construct New 138-12 Sub	UT	30.0	$3,200,000	$106,667
June-06	Campbell Sub - Increase 115-12 Capacity	OR	25.0	$1,400,000	$56,000
			736.7	$72,151,000	$3,109,900
	Plateau 2002 Dollars		30	$2,330,000	
	Plateau 2002 to 2006 Dollars			$2,521,759	
	Plateau 2003 Dollars		187.3	$17,365,000	
	Plateau 2003 to 2006 Dollars			$18,441,630	
	Plateau 2004 Dollars		85.4	$7,094,000	
	Plateau 2004 to 2006 Dollars			$7,404,717	
	Pacific 2004 Dollars		37.5	$2,978,000	
	Pacific 2004 to 2006 Dollars			$3,118,264	
	Pacific 2005 Dollars		86.0	$9,459,000	
	Pacific 2005 to 2006 Dollars			$9,676,557	
	Plateau 2005		195.5	$20,825,000	
	Plateau 2005 to 2006 Dollars			$21,293,563	
	Pacific 2006 Dollars		25.0	$1,400,000	
	Plateau 2006 Dollars		90.0	$10,700,000	
	Total Indexed 2006 Dollars		736.7	$74,556,490	$101,203

	Indexed to 2006
Pacific $'s	$14,194,821
Plateau $'s	$60,361,669
Total $'s	$74,556,490

2006 Incremental Substation Cost $/kVa $ 101.20

PC 1

PacifiCorp
Oregon Marginal Cost Study
Hypothetical Feeder Study Results
Annual Demand and Commitment Costs
December 2006 Dollars

			(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			Demand				Commitment			
			Investment $/kW		Annual $/kW		Investment $/Customer		Annual $/Customer	
Line	Load Class		Poles	Conductor	Poles	Conductor	Poles	Conductor	Poles	Conductor
					(A) x 10.80%	(B) x 10.80%			(E) x 10.80%	(F) x 10.80%
1	Res - Schedule 4	(sec)	$129.88	$215.48	$14.03	$23.27	$615.03	$246.51	$66.42	$26.62
2										
3	GS - Schedule 23									
4	0-15 kW	(sec)	$150.49	$244.74	$16.25	$26.43	$779.42	$312.40	$84.18	$33.74
5	15+ kW	(sec)	$150.49	$244.74	$16.25	$26.43	$779.42	$312.40	$84.18	$33.74
6	Primary	(pri)	$150.49	$244.74	$16.25	$26.43	$779.42	$312.40	$84.18	$33.74
7										
8	GS - Schedule 28									
9	0-50 kW	(sec)	$106.30	$182.14	$11.48	$19.67	$427.87	$171.49	$46.21	$18.52
10	51-100 kW	(sec)	$106.30	$182.14	$11.48	$19.67	$427.87	$171.49	$46.21	$18.52
11	> 101kW	(sec)	$106.30	$182.14	$11.48	$19.67	$427.87	$171.49	$46.21	$18.52
12	Primary	(pri)	$106.30	$182.14	$11.48	$19.67	$427.87	$171.49	$46.21	$18.52
13										
14	GS - Schedule 30									
15	0-300 kW	(sec)	$93.52	$163.72	$10.10	$17.68	$324.13	$129.92	$35.01	$14.03
16	301+ kW	(sec)	$93.52	$163.72	$10.10	$17.68	$324.13	$129.92	$35.01	$14.03
17	Primary	(pri)	$93.52	$163.72	$10.10	$17.68	$324.13	$129.92	$35.01	$14.03
18										
19	LPS - Schedule 48T									
20	1 - 4 MW	(sec)	$71.06	$131.79	$7.67	$14.23	$144.68	$57.98	$15.63	$6.26
21	1 - 4 MW	(pri)	$71.06	$131.79	$7.67	$14.23	$144.68	$57.98	$15.63	$6.26
22	> 4 MW	(sec)	$8.04	$16.31	$0.87	$1.76	$0.00	$0.00	$0.00	$0.00
23	> 4 MW	(pri)	$5.05	$10.26	$0.55	$1.11	$0.00	$0.00	$0.00	$0.00
24										
25	Irrigation - Schedule 41	(sec)	$317.13	$478.56	$34.25	$51.68	$2,091.42	$838.27	$225.87	$90.53
26										
27										
28	The $/kW are in terms of "Feeder" kW's.									

Anderberg/27

PC 2

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors
Poles and Conductor
Three Phase Costs as Demand

Line	(A) Demand Poles Cost	(B) Demand Conductor Cost	(C) Commitment Poles Cost	(D) Commitment Conductor Cost	(E) 2006 Demand Poles Cost	(F) 2006 Demand Conductor Cost	(G) 2006 Commitment Poles Cost	(H) 2006 Commitment Conductor Cost
					(D) x 1.0686	(C) x 1.0698	(B) x 1.0686	(A) x 1.0698
1	Res - Schedule 4							
2	$121.54	$201.42	$575.55	$230.43	$129.88	$215.48	$615.03	$246.51
3								
4	GS - Schedule 23							
5	$140.83	$228.77	$729.38	$292.02	$150.49	$244.74	$779.42	$312.40
6	$140.83	$228.77	$729.38	$292.02	$150.49	$244.74	$779.42	$312.40
7	$140.83	$228.77	$729.38	$292.02	$150.49	$244.74	$779.42	$312.40
8								
9	GS - Schedule 28							
10	$99.48	$170.26	$400.40	$160.30	$106.30	$182.14	$427.87	$171.49
11	$99.48	$170.26	$400.40	$160.30	$106.30	$182.14	$427.87	$171.49
12	$99.48	$170.26	$400.40	$160.30	$106.30	$182.14	$427.87	$171.49
13	$99.48	$170.26	$400.40	$160.30	$106.30	$182.14	$427.87	$171.49
14								
15	GS - Schedule 30							
16	$87.52	$153.04	$303.32	$121.44	$93.52	$163.72	$324.13	$129.92
17	$87.52	$153.04	$303.32	$121.44	$93.52	$163.72	$324.13	$129.92
18	$87.52	$153.04	$303.32	$121.44	$93.52	$163.72	$324.13	$129.92
19								
20	LPS - Schedule 48T							
21	$66.50	$123.19	$135.39	$54.20	$71.06	$131.79	$144.68	$57.98
22	$66.50	$123.19	$135.39	$54.20	$71.06	$131.79	$144.68	$57.98
23	$7.52	$15.25	$0.00	$0.00	$8.04	$16.31	$0.00	$0.00
24	$4.73	$9.59	$0.00	$0.00	$5.05	$10.26	$0.00	$0.00
25								
26	Irrigation - Schedule 41							
27	$296.77	$447.34	$1,957.16	$783.58	$317.13	$478.56	$2,091.42	$838.27

Pacific Region			
	DRI/McGraw-Hill Index		Escalation Factor
	2004	2006	2004 - 2006
Poles	444.5	475.0	1.0686
Conductors	462.6	494.9	1.0698

Footnotes:
Escalation Factors: DRI / McGraw-Hill Cost Trends of Electric Utility Construction, Table A13
Pole and conductor costs from Distribution Feeder Model.

PC 3

PacifiCorp
Oregon Marginal Cost Study
Feeder Distribution Model
Inputs & Calculations

Line	Class		(A) Annual MWH	(B) Number of Customers	(C) Average MWh per Customer (A) / (B)	(D) Hours in Study Period	(E) Average kW / customer per hour (C)/(D)x1000	(F) Feeder Load Factor
1	Res - Schedule 4	(sec)	5,005,318	429,164	11.66	8,760	1.33	60.88%
2	GS - Schedule 23 - 0-15 kW	(sec)	630,728	58,966	10.70	8,760	1.22	65.07%
3	GS - Schedule 23 - 15+ kW	(sec)	402,462	5,089	79.08	8,760	9.03	52.58%
4	GS - Schedule 23 - Primary	(pri)	678	27	25.10	8,760	2.87	55.66%
5	GS - Schedule 28 - 0-50 kW	(sec)	531,902	4,064	130.88	8,760	14.94	63.23%
6	GS - Schedule 28 - 51-100 kW	(sec)	550,061	2,713	202.75	8,760	23.14	64.11%
7	GS - Schedule 28 - > 101kW	(sec)	823,591	1,756	469.02	8,760	53.54	71.53%
8	GS - Schedule 28 - Primary	(pri)	20,141	49	411.05	8,760	46.92	70.56%
9	GS - Schedule 30 - 0-300 kW	(sec)	243,980	263	927.68	8,760	105.90	65.31%
10	GS - Schedule 30 - 301+ kW	(sec)	1,012,653	544	1,861.49	8,760	212.50	67.89%
11	GS - Schedule 30 - Primary	(pri)	85,351	47	1,815.97	8,760	207.30	67.61%
12	Irrigation - Sch 41	(sec)	224,968	8,184	27.49	8,760	3.14	69.16%
13	LPS - Schedule 48T - 1 - 4 MW	(sec)	744,447	132	5,639.75	8,760	643.81	71.07%
14	LPS - Schedule 48T - 1 - 4 MW	(pri)	406,979	54	7,536.65	8,760	860.35	76.29%
15	LPS - Schedule 48T - > 4 MW	(sec)	75,440	3	25,146.67	8,760	2,870.62	88.21%
16	LPS - Schedule 48T - > 4 MW	(pri)	1,308,651	33	39,656.09	8,760	4,526.95	87.47%
17	Total -		12,067,350	511,088				

Customer Distribution on the Hypothetical Feeder Branch

	Class	(A) Hypothetical Feeder Branch 1	(B) 2	(C) 3	(D) 4	(E) 5	(F) 6	(G) 7
1	Res - Schedule 4 (sec)	1.33%	1.33%	1.33%	3.07%	3.07%	3.07%	86.80%
2	GS - Schedule 23 - 0-15 kW (sec)	1.77%	1.77%	1.77%	3.60%	3.60%	3.60%	83.90%
3	GS - Schedule 23 - 15+ kW (sec)	1.77%	1.77%	1.77%	3.60%	3.60%	3.60%	83.90%
4	GS - Schedule 23 - Primary (pri)	1.77%	1.77%	1.77%	3.60%	3.60%	3.60%	83.90%
5	GS - Schedule 28 - 0-50 kW (sec)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%
6	GS - Schedule 28 - 51-100 kW (sec)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%
7	GS - Schedule 28 - > 101kW (sec)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%
8	GS - Schedule 28 - Primary (pri)	0.88%	0.88%	0.88%	2.28%	2.28%	2.28%	90.51%
9	GS - Schedule 30 - 0-300 kW (sec)	0.50%	0.50%	0.50%	2.32%	2.32%	2.32%	91.55%
10	GS - Schedule 30 - 301+ kW (sec)	0.50%	0.50%	0.50%	2.32%	2.32%	2.32%	91.55%
11	GS - Schedule 30 - Primary (pri)	0.50%	0.50%	0.50%	2.32%	2.32%	2.32%	91.55%
12	Irrigation - Sch 41	4.20%	4.20%	4.20%	11.54%	11.54%	11.54%	52.77%
13	LPS - Schedule 48T - 1 - 4 MW (sec)	-	-	-	1.80%	1.80%	1.80%	94.61%
14	LPS - Schedule 48T - 1 - 4 MW (pri)	-	-	-	1.80%	1.80%	1.80%	94.61%
15	LPS - Schedule 48T - > 4 MW (sec)		Large Customer are on dedicated feeder and are not included here					
16	LPS - Schedule 48T - > 4 MW (pri)		Large Customer are on dedicated feeder and are not included here					

System property records & engineering information

Number of pole miles in Oregon	14,239	Poles per mile	24.83
Number of trench miles in Oregon	3,632	Customers per mile	28.60
Number of feeders in Oregon	561	MWH per customer	23.61
Number of poles in Oregon	353,613	MWH per feeder	21,510

PacifiCorp
Oregon Marginal Cost Study
Transformer Commitment Costs

Line	Customer Type	(A) Percent of Customers	(B) Dollars / Tran.	(C) Weighted $ / Tran. (A) x (B)	(D) # Cust. / Tran.	(E) Transformer $ / Cust. (C) / (D)	(F) Average Customers	(G) Tot. Trans. Commitment $ (E) x (F)
1	Res - Schedule 4	100.00%	179.58	179.58	3.54	$50.73	460,491	$23,360,708
2								
3	GS - Schedule 23							
4	1 Phase	83.25%	179.58	149.50	2.56	$58.40		
5	3 Phase	16.75%	430.12	72.04	3.18	$22.65		
6	0-15 kW	100.00%				$81.05	63,230	$5,124,951
7								
8	1 Phase	41.32%	179.58	74.21	2.56	$28.99		
9	3 Phase	58.68%	430.12	252.38	3.18	$79.36		
10	15+ kW	100.00%				$108.35	5,457	$591,283
11								
12	Primary	100.00%	-	-	0.00	0	29	$0
13								
14	GS - Schedule 28							
15	1 Phase	27.02%	179.58	48.53	2.01	$24.14		
16	3 Phase	72.98%	430.12	313.88	2.17	$144.65		
17	0-50 kW					$168.79	4,643	$783,689.37
18								
19	1 Phase	14.74%	179.58	26.48	2.01	$13.17		
20	3 Phase	85.26%	430.12	366.70	2.17	$168.99		
21	51-100 kW	100.00%				$182.16	3,099	$564,515
22								
23	1 Phase	2.33%	179.58	4.19	2.01	$2.08		
24	3 Phase	97.67%	430.12	420.08	2.17	$193.59		
25	> 101kW	100.00%				$195.67	2,006	$392,514
26								
31	Primary	100.00%	-	-	0.00	0	54	$0
32								
33	GS - Schedule 30							
38	1 Phase	0.76%	179.58	1.37	1.82	$0.75		
39	3 Phase	99.24%	430.12	426.85	1.69	$252.57		
40	0-300 kW	100.00%				$253.33	312	$79,038
41								
42	1 Phase	0.00%	179.58	-	1.82	$0.00		
43	3 Phase	100.00%	430.12	430.12	1.69	$254.51		
44	301+ kW	100.00%				$254.51	646	$164,413
45								
46	Primary	100.00%	-	-	0.00	0	56	$0
47								
48	LPS - Schedule 48T							
49	1 - 4 MW (sec)	100.00%	430.12	430.12	1.00	430.12	138	$59,357
50	1 - 4 MW (pri)	100.00%	-	-	0.00	0	56	$0
51	> 4 MW (sec)	100.00%	430.12	430.12	1.00	430.12	3	$1,290
52	> 4 MW (pri)	100.00%	-	-	0.00	0	35	$0
53	Trans (trn)	100.00%	-	-	0.00	0	1	$0
54								
55	Schedule 41- Irrigation							
56	1 Phase	16.72%	179.58	30.02	1.86	$16.14		
57	3 Phase	83.28%	430.12	358.22	1.62	$221.12		
58	Total	100.00%				$237.26	8,338	$1,978,301

XFMR 2

PacifiCorp
Oregon Marginal Cost Study
Transformer Demand Costs

Line	Customer Type		(A) Weighted $ / kW	(B) Annual MWh's	(C) Transformer Load Factor	(D) Transformer Peak kW's (B) / (C) / 8.760	(E) Tot. Trans. Demand $ (A) x (D)
1	Res - Schedule 4	(sec)	$0.68	5,079,177	29.41%	1,971,225	$1,340,433
2							
3	GS - Schedule 23						
4	0-15 kW	(sec)	$0.88	678,078	34.20%	226,366	$199,202
5	15+ kW	(sec)	$0.88	432,675	57.56%	85,814	$75,516
6	Primary	(pri)	$0.00	728	NA	0	$0
7							
8	GS - Schedule 28						
9	0-50 kW	(sec)	$0.88	582,614	38.67%	172,003	$151,363
10	51-100 kW	(sec)	$0.88	602,504	55.16%	124,681	$109,719
11	> 101kW	(sec)	$0.88	902,113	66.08%	155,843	$137,141
12	Primary	(pri)	$0.00	22,353	NA	0	$0
13							
14	GS - Schedule 30						
15	0-300 kW	(sec)	$0.88	260,390	59.65%	49,835	$43,855
16	301+ kW	(sec)	$0.88	1,080,762	64.54%	191,154	$168,216
17	Primary	(pri)	$0.88	91,525	NA	0	$0
18							
19							
20	LPS - Schedule 48T						
21	1 - 4 MW	(sec)	$0.88	821,613	69.60%	134,760	$118,589
22	1 - 4 MW	(pri)	$0.00	444,269	NA	0	$0
23	> 4 MW	(sec)	$0.88	82,940	91.97%	10,295	$9,060
24	> 4 MW	(pri)	$0.00	1,428,559	NA	0	$0
25	Trans	(trn)	$0.00	614,130	NA	0	$0
26							
27	Irrigation - Schedule 41 (Average)						
28	Secondary	(sec)	$0.88	206,654	47.05%	50,139	$44,122
29							
30							
31	Totals			13,331,083		3,172,115	$2,397,216

Footnote: Residential $/kW is decreased by 23% (1/1.3) to account for higher transformer load capacities at the time of residential peak.

PacifiCorp
Oregon Marginal Cost Study
Calculation of Escalation Factors for Transformers
(Regression weighted by number of transformer banks)

Line	Description	(A) Demand Related	(B) Adjusted for System Power Factor of .95	(C) Commitment Related	(D) Indexed to 2006	(E) Annualized $ @ 10.80%
			(A) / .95		(B) or (C) x 1.0193	(D) x 10.80%
1	1 Phase $/kW	$7.63	$8.03		$8.18	$0.88
2						
3	3 Phase $/kW	$7.63	$8.03		$8.18	$0.88
4						
5	1 Phase			$1,631.27	$1,662.75	$179.58
6	$/Transformer					
7						
8	3 Phase			$2,275.89		
9	Dummy Variable					
10						
11	3 Phase			$3,907.16	$3,982.57	$430.12
12	$/Transformer					

Pacific Region		
DRI Index		Escalation Factor
2004	2006	2004 - 2006
259.3	264.3	1.0193

Footnotes: Escalation Factors: DRI / McGraw-Hill Cost Trends of Electric Utility Construction, Table A13

PacifiCorp
Oregon Marginal Cost Study
Distribution O&M Expense
Loading Factor as a Percent of Dist. Plant
(Excluding Meters and St Ltg)

Line	Description	(A) 1994	(B) 1995	(C) 1996	(D) 1997	(E) 1998	(F) 1999	(G) 2000	(H) 2001	(I) 2002	(J) 2003
	Distribution O & M Expenses										
1	Total Distribution O & M Expense	28,499,551	30,253,085	30,515,885	31,837,286	33,064,114	34,852,307	42,485,996	48,122,256	48,559,856	48,811,823
2	Less:										
3	585 St Ltg & Signal Systems	291,527	208,020	239,532	232,242	265,823	-	-	-	-	13,067
4	586 Meter Expense	1,991,904	2,147,244	2,681,365	1,819,665	2,283,801	-	-	1,479,307	1,800,451	2,010,097
5	587 Customer Installation Expense	1,416,565	1,367,268	1,265,873	1,292,182	1,328,126	332,819	132,472	11,531	9,542	90,751
6	596 Main. of St Ltg & Signal Systems	146,761	233,618	293,622	287,822	239,770	249,477	289,510	609,632	814,491	756,545
7	597 Main. of Meters	211,932	222,841	291,927	245,893	256,703	1,047,453	674,571	664,777	825,166	1,190,462
8											
9	Total Adjusted Distribution O & M Expense	24,440,862	26,074,094	25,743,566	27,959,482	28,689,891	33,222,557	41,389,443	45,357,009	45,110,206	44,750,901
10	Line 1 - (Lines 3 through 7)										
11											
12											
13	Distribution Plant										
14	Total Distribution Plant	892,979,730	969,178,927	1,042,583,318	1,115,443,667	1,162,012,609	1,192,703,978	1,235,859,101	1,271,410,972	1,303,063,520	1,341,098,219
15	Less:										
16	370 Meters	45,872,071	49,995,217	51,408,414	53,572,362	54,919,747	56,597,405	55,765,666	56,108,548	57,067,003	56,828,689
17	373 Street Lighting	9,722,655	10,669,831	11,805,627	12,899,574	13,742,452	14,339,640	15,038,442	15,408,466	16,135,274	16,827,066
18											
19	Adjusted Distribution Plant	837,385,004	908,513,879	979,369,277	1,048,971,731	1,093,350,410	1,121,766,933	1,165,054,993	1,199,893,958	1,229,861,243	1,267,442,464
20	Line 14 - Line 16 - Line 17										
21											
22											
23	O & M Expense Loading Factor										
24	Distribution O & M Loading	2.92%	2.87%	2.63%	2.67%	2.62%	2.96%	3.55%	3.78%	3.67%	3.53%
25	Line 9 / Line 19										
26											
27	Average Distribution O & M Loading	3.12%									
28	Average of Line 24										
29											
30	Distribution Annual Charge	10.80%									
31											
32	Annualized Distribution O & M Loading Factor	28.89%									
33	Line 27 / Line 30										

Footnotes:
Source: FERC Form 1 (State of Oregon), Dec 31, 2003

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(B) % of Customers 1 & 3 Phase (A) / (A,Ttl)	(C) % of Customers 1 Phase (A) / 1Ø	(D) % of Customers 3 Phase (A) / 3Ø	(E) Metering Cost	(F) Weighted Metering Cost 1 & 3 Phase (B) x (E)	(G) Weighted Metering Cost 1 Phase (C) x (E)	(H) Weighted Metering Cost 3 Phase (D) x (E)
1	Res - Schedule 4	429,164	100.00%	100.00%		$97	$96.50	$96.50	
2	Annualized - (Line 1) x 10.80%						$10.42	$10.42	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	49,087	83.25%	99.99%		$78	$65.21	$78.34	
7	kW = 0, 3 Phase	9,868	16.74%		99.92%	$247	$41.37		$247.03
8	kW > 1, 1 Phase	3	0.01%	0.01%		$184	$0.01	$0.01	
9	kW > 1, 3 Phase	8	0.01%		0.08%	$247	$0.03		$0.20
10	Total 0-15 kW	58,966	100.00%	100.00%	100.00%		$106.62	$78.35	$247.23
11	Annualized - (Line 10) x 10.80%						$11.51	$8.46	$26.70
12									
13	15+ kW								
14	1 Phase	2,103	41.32%	100.00%		$201	$83.25	$201.45	
15	3 Phase W/O KVAR	2,986	58.68%		100.00%	$247	$145.06		$247.23
16	3 Phase With KVAR	-	0.00%		0.00%	$408	$0.00		$0.00
17	Total 15+ kW	5,089	100.00%	100.00%	100.00%		$228.31	$201.45	$247.23
18	Annualized - (Line 17) x 10.80%						$24.66	$21.76	$26.70
19									
20	Primary								
21	12.47 KV 4-wire Wye OH	27	100.00%		100.00%	$7,559	$7,559.28		$7,559.28
22	Annualized - (Line 21) x 10.80%						$816.40	$0.00	$816.40
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	10	0.25%	0.91%		$201	$0.50	$1.83	
27	kW = 0, 3 Phase	315	7.75%		10.62%	$247	$19.17		$26.27
28	kW > 1, 1 Phase	1,088	26.78%	99.09%		$201	$53.94	$199.61	
29	kW > 1, 3 Phase	2,650	65.22%		89.38%	$247	$161.25		$220.96
30	Total 0-50 kW	4,063	100.00%	100.00%	100.00%		$234.86	$201.44	$247.23
31	Annualized - (Line 30) x 10.80%						$25.36	$21.76	$26.70
32									
33	51-100 kW								
34	1 Phase	400	14.74%	100.00%		$201	$29.70	$201.45	
35	3 Phase W/O KVAR	2,313	85.26%		100.00%	$247	$210.78		$247.23
36	3 Phase With KVAR	-	0.00%		0.00%	$408	$0.00		$0.00
37	Total 51-100 kW	2,713	100.00%	100.00%	100.00%		$240.48	$201.45	$247.23
38	Annualized - (Line 37) x 10.80%						$25.97	$21.76	$26.70
39									
40	> 101kW								
41	1 Phase	41	2.33%	100.00%		$809	$18.89	$808.83	
42	3 Phase W/O KVAR	1,715	97.67%		100.00%	$1,264	$1,234.11		$1,263.61
43	3 Phase With KVAR	-	0.00%		0.00%	$1,264	$0.00		$0.00
44	Total > 101kW	1,756	100.00%	100.00%	100.00%		$1,253.00	$808.83	$1,263.61
45	Annualized - (Line 44) x 10.80%						$135.32	$87.35	$136.47
46									
47	Primary								
48	12.47 KV 4-wire Wye OH	49	100.00%		100.00%	$7,559	$7,559.28		$7,559.28
49	Annualized - (Line 48) x 10.80%						$816.40	$0.00	$816.40

Footnote:

Meters 2

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Meter Costs
GS - Schedule 30 / LPS - Schedule 48T / Irrigation - Schedule 41 (Annual)

Line	Load Class	(A) Customers	(B) % of Customers: 1 & 3 Phase (A) / (A,Ttl)	(C) % of Customers: 1 Phase (A) / 1Ø	(D) % of Customers: 3 Phase (A) / 3Ø	(E) Metering Cost	(F) Weighted Metering Cost: 1 & 3 Phase (B) x (E)	(G) Weighted Metering Cost: 1 Phase (C) x (E)	(H) Weighted Metering Cost: 3 Phase (D) x (E) (F) x 10.80%
1	GS - Schedule 30								
2	0-300 kW								
3	1 Phase	2	0.76%	100.00%		$809	$6.15	$808.83	
4	3 Phase W/O KVAR	261	99.24%		100.00%	$1,264	$1,254.00		$1,263.61
5	3 Phase With KVAR	-	0.00%		0.00%	$1,264	$0.00		$0.00
6	Total 0-300 kW	263	100.00%	100.00%	100.00%		$1,260.15	$808.83	$1,263.61
7	Annualized - (Line 6) x 10.80%						$136.10	$87.35	$136.47
8									
9	301+ kW								
10	1 Phase	0	0.00%	0.00%		$847	$0.00	$0.00	
11	3 Phase W/O KVAR	544	100.00%		100.00%	$1,264	$1,263.61		$1,263.61
12	3 Phase With KVAR	0	0.00%		0.00%	$1,264	$0.00		$0.00
13	301+ kW	544	100.00%	0.00%	100.00%		$1,263.61	$0.00	$1,263.61
14	Annualized - (Line 13) x 10.80%						$136.47	$0.00	$136.47
15									
16	Primary								
17	12.47 KV 4-wire Wye OH	47	100.00%		100.00%	$7,559	$7,559.28		$7,559.28
18	Annualized - (Line 17) x 10.80%						$816.40		$816.40
19									
20	LPS - Schedule 48T								
21	1 - 4 MW (sec)	132	100.00%		100.00%	$1,632	$1,631.91		$176.25
22	1 - 4 MW (pri)	54	100.00%		100.00%	$7,559	$7,559.28		$816.40
23	> 4 MW (sec)	3	100.00%		100.00%	$1,632	$1,631.91		$176.25
24	> 4 MW (pri)	33	100.00%		100.00%	$7,559	$7,559.28		$816.40
25	Trans (trn)	1	100.00%		100.00%	$155,000	$155,000.00		$16,740.00
26		223							
27	Irrigation - Schedule 41 (Annual)								
28	0 - 50 kW								
29	kW = 0, 1 Phase	205	2.50%	14.99%		$78	$1.96	$11.74	
30	kW = 0, 3 Phase	866	10.58%		12.71%	$247	$26.16		$31.41
31	kW > 1, 1 Phase	1,162	14.20%	84.94%		$184	$26.15	$156.42	
32	kW > 1, 3 Phase	5,119	62.55%		75.10%	$247	$154.64		$185.68
33									
34	51 - 300 kW								
35	1 Phase	1	0.01%	0.07%		$201	$0.02	$0.15	
36	3 Phase W/O KVAR	812	9.92%		11.91%	$247	$24.53		$29.45
37	3 Phase With KVAR	-	0.00%		0.00%	$408	$0.00		$0.00
38									
39	> 300 kW								
40	1 Phase	-	0.00%	0.00%		$847	$0.00	$0.00	
41	3 Phase W/O KVAR	19	0.23%		0.28%	$1,264	$2.93		$3.52
42	3 Phase With KVAR	-	0.00%		0.00%	$1,264	$0.00		$0.00
43	Total Irrigation	8,184	100.00%	100.00%	100.00%		$236.39	$168.31	$250.06
44							$25.53	$18.18	$27.01
45									
46	Primary	-	100.00%		100.00%	$0	$0.00		$0.00
47							$0.00	$0.00	$0.00

Footnote:
Customer inputs from Pricing Dept - data based on FY 2004.

Meters 3

PacifiCorp
Oregon Marginal Cost Study
Increment Three Phase
Meter and Services Costs

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
		Meters				Service Drops			
Line	Load Class	Single Phase	Three Phase	Difference	Annualized Difference	Single Phase	Three Phase	Difference	Annualized Difference
				(B) - (A)	(C) x 10.80%			(F) - (E)	(G) x 10.80%
1	Residential	$96.50	$247.23	$150.73	$16.28	$494.95	$681.76	$186.81	$20.18
2									
3	0-15 kW	$78.34	$247.23	$168.89	$18.24	$581.82	$767.46	$185.64	$20.05
4									
5	16-100 kW	$201.45	$247.23	$45.78	$4.94	$1,035.83	$1,412.62	$376.79	$40.69
6									
7	101-1000 kW	$847.49	$1,263.61	$416.12	$44.94	$3,206.82	$2,872.99	($333.82)	($36.05)
8									
9	1 - 4 MW	N.A.	$1,631.91	$1,631.91	$176.25	N.A.	$5,598.00	$5,598.00	$604.58

Meters 4

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Meters

Line	Load Class	(A) Metering Standard	(B) Meter Cost in 2004 Dollars	(C) Indexed to 2006	(D) Percent Use	(E) Total Installed Cost per Service
	Residential					
1	Overhead (small load)	DM221A	$77.00	$78.34	49.00%	$38.39
2	Overhead (all electric)	DM221D	$112.00	$113.95	51.00%	$58.11
3					100.00%	$96.50
4						
5	0 - 15 kW					
6	kW = 0, 1 Phase OH	DM221A	$77.00	$78.34	100.00%	$78.34
7				$162.78		
8	kW = 0, 3 Phase OH	DM241A	$243.00	$247.23	100.00%	$247.23
9						
10	kW > 1, 1 Phase OH	DM221B	$181.00	$184.15	100.00%	$184.15
11						
12	kW > 1, 3 Phase OH	DM241A	$243.00	$247.23	100.00%	$247.23
13				$120.58		
14				$58.16		$178.74
15	15 - 100 kW					
16	1 Phase OH	DM221C	$198.00	$201.45	100.00%	$201.45
17				$224.34		
18	3 Phase wo / KVAR OH	DM241A	$243.00	$247.23	100.00%	$247.23
19						
20	3 Phase with KVAR OH	DM241B	$401.00	$407.98	100.00%	$407.98
21						
22						
23	100 - 300 kW					
24	1 Phase OH	DM231ABB	$795.00	$808.83	100.00%	$808.83
25						
26	3 Phase wo / KVAR OH	DM271AEC	$1,242.00	$1,263.61	100.00%	$1,263.61
27						
28	3 Phase with KVAR OH	DM271AEC	$1,242.00	$1,263.61	100.00%	$1,263.61
29						
30						
31	300-1000 kW					
32	W/O KVAR, 1 Phase OH	DM231AFE	$833.00	$847.49	100.00%	$847.49
33						
34	W/O KVAR, 3 Phase OH	DM271AEC	$1,242.00	$1,263.61	100.00%	$1,263.61
35						
36	W/KVAR, 3 Phase OH	DM271AEC	$1,242.00	$1,263.61	100.00%	$1,263.61
37						
38						
39	1000 kW and over					
40	Secondary Volt(1) OH	DM271AFG	$1,604.00	$1,631.91	100.00%	$1,631.91
41						
42	Primary Metering					
43	13.8 KV 3-wire OH	DM101ACBI	$6,374.00	$6,484.91		$6,484.91
44	12.47 KV 4-wire Wye OH	DM121ABBI	$7,430.00	$7,559.28		$7,559.28
45	24.9 KV 4-wire Wye OH	DM121AGBI	$12,001.00	$12,209.82		$12,209.82
46	35 KV 4-wire Wye OH	DM131ABH	$22,929.00	$23,327.96		$23,327.96

Source: Summary of Average Installed Cost For Meters and Associated Equipment - Revised to Eliminate Trave Time for Loads Less Than 100 kW

Further Breakdown of Overhead

% of Overhead Which Are Small Load	49.00%
% of Overhead Which Are All Electric	51.00%

Pacific Region		
DRI/McGraw-Hill Index		Escalation Factor
2004	2006	2004 - 2006
258.9	263.4	1.0174

Footnotes:
Escalation Factors: DRI / McGraw-Hill Cost Trends of Electric Utility Construction, Table A13

PacifiCorp
Oregon Marginal Cost Study
Distribution Meters Expense
Loading Factor

Line	Description	(A) 1994	(B) 1995	(C) 1996	(D) 1997	(E) 1998	(F) 1999	(G) 2000	(H) 2001	(I) 2002	(J) 2003
	Distribution Meters Expenses										
1	586 Meter Expense	1,991,904	2,147,244	2,681,365	1,819,665	2,283,801	-	-	1,479,307	1,800,451	2,010,097
2	597 Main. of Meters	211,932	222,841	291,927	245,893	256,703	1,047,453	674,571	664,777	825,166	1,190,462
3											
4	Total Adjusted Distribution Meters Expens	2,203,836	2,370,085	2,973,292	2,065,558	2,540,504	1,047,453	674,571	2,144,084	2,625,617	3,200,559
5	Line 1 + Line 2										
6											
7											
8											
9	Distribution Meters										
10	370 Meters	45,872,071	49,995,217	51,408,414	53,572,362	54,919,747	56,597,405	55,765,666	56,108,548	57,067,003	56,828,689
11											
12											
13											
14	Meters Expense Loading Factor										
15	Meter O&M Loading	4.80%	4.74%	5.78%	3.86%	4.63%	1.85%	1.21%	3.82%	4.60%	5.63%
16	Line 3 / Line 4										
17											
18	Average Meter O&M Loading	4.09%									
19	Average of Line 5										
20											
21	Distribution Annual Charge	10.80%									
22											
23	Annualized Meter O&M Loading Factor	37.89%									
24	Line 6 / Line 7										

Services 1

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
Res - Schedule 4 / GS - Schedule 23 / GS - Schedule 28

Line	Load Class	(A) Customers	(B) % of Customers 1 & 3 Phase (A) / (A,Ttl)	(C) % of Customers 1 Phase (A) / 1Ø	(D) % of Customers 3 Phase (A) / 3Ø	(E) Service Drop Cost	(F) Weighted Service Drop Cost 1 & 3 Phase (B) x (E)	(G) Weighted Service Drop Cost 1 Phase (C) x (E)	(H) Weighted Service Drop Cost 3 Phase (D) x (E)
1	Res - Schedule 4	429,164	100.00%	100.00%		$406	$406.21	$406.21	
2	Annualized - Line 1 x 10.80%						$43.87	$43.87	
3									
4	GS - Schedule 23								
5	0-15 kW								
6	kW = 0, 1 Phase	49,087	83.25%	99.99%		$495	$412.03	$494.92	
7	kW = 0, 3 Phase	9,868	16.74%		99.92%	$682	$114.09		$681.21
8	kW > 1, 1 Phase	3	0.01%	0.01%		$582	$0.03	$0.04	
9	kW > 1, 3 Phase	8	0.01%		0.08%	$767	$0.10		$0.62
10	Total 0-15 kW	58,966	100.00%	100.00%	100.00%		$526.25	$494.96	$681.83
11	Annualized - Line 10 x 10.80%						$56.84	$53.46	$73.64
12									
13	15+ kW								
14	1 Phase	2,103	41.32%	100.00%		$1,036	$428.05	$1,035.83	
15	3 Phase W/O KVAR	2,986	58.68%		100.00%	$1,413	$828.86		$1,412.62
16	3 Phase With KVAR	0	0.00%		0.00%	$1,413	$0.00		$0.00
17	Total 15+ kW	5,089	100.00%	100.00%	100.00%		$1,256.91	$1,035.83	$1,412.62
18	Annualized - Line 17 x 10.80%						$135.75	$111.87	$152.56
19									
20	Primary								
21	12.47 KV 4-wire Wye OH	27	100.00%		100.00%	$1,413		$1,412.62	$0.00
22	Annualized - (Line 21) x 10.80%					$152.56	$0.00	$152.56	$0.00
23									
24	GS - Schedule 28								
25	0-50 kW								
26	kW = 0, 1 Phase	10	0.25%	0.91%		$1,036	$2.55	$9.43	
27	kW = 0, 3 Phase	315	7.75%		10.62%	$1,413	$109.52		$150.08
28	kW > 1, 1 Phase	1,088	26.78%	99.09%		$1,036	$277.38	$1,026.39	
29	kW > 1, 3 Phase	2,650	65.22%		89.38%	$1,413	$921.35		$1,262.54
30	Total 0-50 kW	4,063	100.00%	100.00%	100.00%		$1,310.80	$1,035.82	$1,412.62
31	Annualized - Line 30 x 10.80%						$141.57	$111.87	$152.56
32									
33	51-100 kW								
34	1 Phase	400	14.74%	100.00%		$1,036	$152.72	$1,035.83	
35	3 Phase W/O KVAR	2,313	85.26%		100.00%	$1,413	$1,204.35		$1,412.62
36	3 Phase With KVAR	0	0.00%		0.00%	$1,413	$0.00		$0.00
37	Total 51-100 kW	2,713	100.00%	100.00%	100.00%		$1,357.07	$1,035.83	$1,412.62
38	Annualized - Line 37 x 10.80%						$146.56	$111.87	$152.56
39									
40	> 101kW								
41	1 Phase	41	2.33%	100.00%		$3,207	$74.87	$3,206.82	
42	3 Phase W/O KVAR	1,715	97.67%		100.00%	$2,873	$2,805.91		$2,872.99
43	3 Phase With KVAR	0	0.00%		0.00%	$2,873	$0.00		$0.00
44	Total > 101kW	1,756	100.00%	100.00%	100.00%		$2,880.78	$3,206.82	$2,872.99
45	Annualized - Line 44 x 10.80%						$311.12	$346.34	$310.28
46									
47	Primary								
48	12.47 KV 4-wire Wye OH	49	100.00%		100.00%	$0	$0.00		$0.00
49	Annualized - (Line 48) x 10.80%						$0.00	$0.00	$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on FY 2004.

PacifiCorp
Oregon Marginal Cost Study
Weighted Average Installed Service Drop Costs
GS - Schedule 30 / LPS - Schedule 48T / Irrigation - Schedule 41 (Annual)

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
			% of Customers			Service Drop Cost	Weighted Service Drop Cost		
Line	Load Class	Customers	1 & 3 Phase	1 Phase	3 Phase		1 & 3 Phase	1 Phase	Annualized 3 Phase
			(A) / (A,Ttl)	(A) / 1Ø	(A) / 3Ø		(B) x (E)	(C) x (E)	
1	GS - Schedule 30								
3	0-300 kW								
4	1 Phase	2	0.76%	100.00%		$3,207	$24.39	$3,206.82	
5	3 Phase W/O KVAR	261	99.24%		100.00%	$2,873	$2,851.15		$2,872.99
6	3 Phase With KVAR	-	0.00%		0.00%	$2,873	$0.00		$0.00
7	Total 0-300 kW	263	100.00%	100.00%	100.00%	$8,953	$2,875.54	$3,206.82	$2,872.99
8	Annualized - Line 7 x 10.80%						$310.56	$346.34	$310.28
9									
10	301+ kW								
11	1 Phase	0	0.00%	100.00%		$3,207	$0.00	$3,206.82	
12	3 Phase W/O KVAR	544	100.00%		100.00%	$2,873	$2,872.99		$2,872.99
13	3 Phase With KVAR	0	0.00%		0.00%	$2,873	$0.00		$0.00
14	Total 301+ kW	544	100.00%	100.00%	100.00%		$2,872.99	$3,206.82	$2,872.99
15	Annualized - Line 14 x 10.80%						$310.28	$346.34	$310.28
16									
17	Primary								
18	12.47 KV 4-wire Wye OH	47	100.00%		100.00%	$0	$0.00		$0.00
19	Annualized - Line 18 x 10.80%						$0.00		$0.00
20									
21	LPS - Schedule 48T								
22	1 - 4 MW (sec)	132	100.00%		100.00%	$5,598	$5,598.00		$604.58
23	1 - 4 MW (pri)	54	100.00%		100.00%	$0	$0.00		$0.00
24	> 4 MW (sec)	3	100.00%		100.00%	$5,598	$5,598.00		$604.58
25	> 4 MW (pri)	33	100.00%		100.00%	$0	$0.00		$0.00
26	Trans (trn)	1	100.00%		100.00%	$0	$0.00		$0.00

Footnote:
Column A - Customer inputs from Pricing Dept - data based on FY 2004.
Column (E) - see Tab 12.3 (Services 3:) `Summary of Average Installed Costs Service Drops'

Services 3

PacifiCorp
Oregon Marginal Cost Study
Summary of Average Installed Costs
Service Drops

Line	Load Class	(A) Service Conductor	(B) Cost	(C) Indexed to 2006	(D) Percent Use	(E) Total Cost per Service
				(B) x 1.0546 - OH		
				(B) x 1.0427 - UG		
39	W/O KVAR, 3 Phase	OH - 3-4/0 Quadruplex	$2,810	$2,963	35.31%	$1,046.39
40		4-350 Quad	$2,708	$2,824	64.69%	$1,826.61
41						$2,872.99
42						
43	W/KVAR, 3 Phase	OH - 3-4/0 Quadruplex	$2,810	$2,963	35.31%	$1,046.39
44		4-350 Quad	$2,708	$2,824	64.69%	$1,826.61
45						$2,872.99
46	1000 kW and Over					
47	Secondary Volt(1)	3-750 kcmil Quad.	$4,777	$5,038	35.31%	$1,778.86
48		4-750 kcmil Quad.	$5,662	$5,904	64.69%	$3,819.15
49						$5,598.00
50						
51	Primary Volt	---	---	---		---

Pacific Region			
	DRI/McGraw-Hill Index		Escalation Factor
Service Type	2004	2006	2004 - 2006
Overhead	391.8	413.2	1.0546
Underground	285.4	297.6	1.0427

		Weighted %
Overhead % =	35.31%	
% of Overhead Which Are Small Load=	49.00%	17.30%
% of Overhead Which Are All Electric=	51.00%	18.01%
Underground % =	64.69%	
% of Underground Which Are Small Load=	1.00%	0.65%
% of Underground Which Are All Electric=	99.00%	64.04%
Total OH & UG		100.00%

Cust Exp Sum

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer Accounting Expense
By Schedule
December 2006 Dollars

Line	FERC Account	Description	(A) Sch. 4 Res	(B) Sch. 23 Com	(C) Sch. 28 Com	(D) Sch. 30 Com	(E) Sch. 48T Ind	(F) Sch. 41 Irrigation	(G) Streetlighting	(H) Total
1		Average Number of Customers	460,491	68,716	9,802	1,014	232	3,530	987	544,772
2										
3		Write-offs By Schedule	3,912,403	102,230	155,512	85,682	106,567	39,605	-	4,401,999
4										
5	901									
6	Supervision	Account 902 + 903 + 904	$20,832,247	$2,573,932	$968,624	$207,387	$353,136	$412,510	$19,298	$25,367,134
7		% of Total 902 + 903 +904	82.12%	10.15%	3.82%	0.82%	1.39%	1.63%	0.08%	100.00%
8		Total 901 $	$4,574,660	$565,223	$212,705	$45,541	$77,547	$90,585	$4,238	$5,570,499
9		Dollars Per Customer	$9.93	$8.23	$21.70	$44.91	$334.25	$25.66	$4.29	$10.23
10	902									
11	Meter Reading Expense	902 Weighting Factor	1.00	1.41	2.25	2.25	2.99	2.70	0.00	
12		Weighted Customers	460,491	96,890	22,055	2,282	694	9,531	0	591,941
13		% of Total $	77.79%	16.37%	3.73%	0.39%	0.12%	1.61%	0.00%	100.00%
14		Total 902 $	$4,805,436	$1,011,087	$230,149	$23,809	$7,239	$99,463	$0	$6,177,182
15		Dollars Per Customer	$10.44	$14.71	$23.48	$23.48	$31.20	$28.18	$0.00	$11.34
16	903									
17	Cust. Receipts & Collect.	903 Weighting Factor	1.00	0.94	2.34	2.34	36.07	3.29	0.90	
18		Weighted Customers	460,491	64,709	22,974	2,377	8,369	11,605	889	571,414
19		% of Total $	80.59%	11.32%	4.02%	0.42%	1.46%	2.03%	0.16%	100.00%
20		Total 903 $	$10,001,229	$1,405,398	$498,968	$51,617	$181,771	$252,050	$19,298	$12,410,332
21		Dollars Per Customer	$21.72	$20.45	$50.90	$50.90	$783.50	$71.40	$19.55	$22.78
22	904									
23	Uncollectibles	Total 904 $	$6,025,582	$157,447	$239,507	$131,961	$164,126	$60,997	$0	$6,779,620
24		% of Write-offs	88.88%	2.32%	3.53%	1.95%	2.42%	0.90%	0.00%	
25		Dollars Per Customer	$13.09	$2.29	$24.43	$130.14	$707.44	$17.28	$0.00	$12.44
26	905									
27	Misc Cust Acct Expense	Account 902 + 903 + 904	$20,832,247	$2,573,932	$968,624	$207,387	$353,136	$412,510	$19,298	$25,367,134
28		% of Total 902 + 903 +904	82.12%	10.15%	3.82%	0.82%	1.39%	1.63%	0.08%	100.00%
29		Total 905 $	$597,078	$73,772	$27,762	$5,944	$10,121	$11,823	$553	$727,053
30		Dollars Per Customer	$1.30	$1.07	$2.83	$5.86	$43.63	$3.35	$0.56	$1.33
31	907-910									
32	Supervision, Cust. Assist.	Average Number of customers	460,491	68,716	9,802	1,014	232	3,530	987	543,785
33	Info & Instructional Exp.,	% of Total	84.68%	12.64%	1.80%	0.19%	0.04%	0.65%	0.18%	100.00%
34	Misc Cust Svc & Info Exp.		$2,013,274	$300,427	$42,854	$4,433	$1,014	$15,434	$4,315	$2,377,437
35		Dollars Per Customer	$4.37	$4.37	$4.37	$4.37	$4.37	$4.37	$4.37	$4.36
36										
37	Total 901 - 910	Total 901 - 910 $	$28,017,258	$3,513,355	$1,251,946	$263,306	$441,818	$530,352	$28,404	$34,018,034
38										
39		Dollars Per Customer	$60.84	$51.13	$127.72	$259.67	$1,904.39	$150.24	$28.78	$62.44

Cust Exp Year

PacifiCorp
Oregon Marginal Cost Study
Summary of Customer and Metering Expenses
December 2006 Dollars

Line	Description	(A) Actual 1999 Dollars	(B) Actual 2000 Dollars	(C) Actual 2001 Dollars	(D) Actual 2002 Dollars	(E) Actual 2003 Dollars	(F) Adjusted 2006 Dollars [(A) x 1.1887+ (B) x 1.1597+ (C) x 1.1314+ (D) x 1.1038+ (E) x 1.0769] / 5
	Customer Accounting						
1	901 Supervision	7,759,575	7,101,431	3,354,894	3,025,373	3,025,374	$5,570,499
2	902 Meter Reading Expense	4,340,149	5,693,901	5,618,486	5,144,957	6,581,669	$6,177,182
3	903 Cust Records & Collection	8,844,813	8,234,758	12,301,979	11,116,621	14,670,810	$12,410,332
4	904 Uncollectible Accounts	6,414,162	2,730,654	5,995,980	6,586,619	8,406,244	$6,779,620
5	905 Misc Cust Acct Expense	1,391,917	334,027	539,153	510,949	389,396	$727,053
6	Total	28,750,616	24,094,771	27,810,492	26,384,519	33,073,493	$31,664,686
7							
8	Customer Service & Info Expense						
9	907 Supervision	-	-	-	-	967,318	$208,341
10	908 Cust Assistance Expense	116,371	1,952,441	947,797	841,270	871,273	$1,068,356
11	909 Info & Instructional Expense	5,078	14,632	146,663	204,561	302,597	$148,120
12	910 Misc Cust Svc & Info Expense	3,195,675	450,865	148,073	110,054	141,635	$952,620
13	Total	3,317,124	2,417,938	1,242,533	1,155,885	2,282,823	$2,377,437
14							
15	Distribution Expenses						
16	586 Meter Expenses	$0	$0	$1,479,307	$1,800,451	$2,010,097	$1,165,140
17	597 Meter Maintenance	$1,047,453	$674,571	$664,777	$825,166	$1,190,462	$994,472
18		$1,047,453	$674,571	$2,144,084	$2,625,617	$3,200,559	$2,159,612
19							
20							
21	(1) Inflation Adjustment -	1.1887	1.1597	1.1314	1.1038	1.0769	

Source:
FERC Form 1, State of Oregon
Line 10 - O&M Expense reports summary

Exp Acct 903

Pacificorp
Oregon Marginal Cost Study
Account 903 Cust. Bill & Acctng
Weighting Factors

			(A)	(B)	(C)	(D)	(E)	(F)	(G)
		Description	Residential	Small GS	Large GS	Industrial	Irrigation	Streetlighting	Total
	System customers -	1998 Total PacifiCorp Customers	1,191,897	157,651	20,020	564	10,432	35,274	1,415,838
116									
117	903.6	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	
118	Strategy	Weighted customers	1,191,897	157,651	20,020	564	10,432	35,274	1,415,838
119		% of Total	84.18%	11.13%	1.41%	0.04%	0.74%	2.49%	100.00%
120		Total $	$308	$41	$5	$0	$3	$9	$366
121									
122	903.8	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	
123	Safety	Weighted customers	1,191,897	157,651	20,020	564	10,432	35,274	1,415,838
124		% of Total	84.18%	11.13%	1.41%	0.04%	0.74%	2.49%	100.00%
125		Total $	$1,396,040	$184,653	$23,449	$661	$12,219	$41,316	$1,658,337
126									
127	903.9	Weighting	1.00	1.00	1.00	1.00	1.00	1.00	
128	Training	Weighted customers	1,191,897	157,651	20,020	564	10,432	35,274	1,415,838
129		% of Total	84.18%	11.13%	1.41%	0.04%	0.74%	2.49%	100.00%
130		Total $	$997,650	$131,958	$16,757	$472	$8,732	$29,525	$1,185,095
131									
132	Total Acct. 903	Total 903 $	$28,773,083	$3,583,883	$1,132,759	$491,170	$827,913	$766,583	$35,575,391
133		Dollars Per Customer	$24.14	$22.73	$56.58	$870.87	$79.36	$21.73	
134									
135		Weighting Factor for 903	1.00	0.94	2.34	36.07	3.29	0.90	

AG Expenses

PacifiCorp
Oregon Marginal Cost Study
Administrative & General Expense
Loading Factor

Year	(A) Administrative and General Expenses (000)	(B) Electric Plant in Service (000)	(C) Admin. & General to Electric Plant In Service Loading Factor (A) / (B)
1994	$148,050	$10,255,241	1.44%
1995	$165,528	$10,596,558	1.56%
1996	$180,620	$11,102,582	1.63%
1997	$403,998	$11,416,667	3.54%
1998	$338,402	$11,784,334	2.87%
1999	$209,710	$12,110,787	1.73%
2000	$100,360	$11,910,796	0.84%
2001	$180,629	$12,289,187	1.47%
2002	$277,395	$12,690,449	2.19%
2003	$251,357	$13,208,159	1.90%
10 Year Average A&G to EPIS Loading Factor			1.92%

Footnotes:
(A) FERC Form 1 Page 321-322
(B) FERC Form 1 Page 206-207

Charge 1

PacifiCorp
Oregon Marginal Cost Study
Calculation of Annual Charges

Line	Description	(A) 20 years - Generation	(B) 10 years - Generation	(C) 5 years - Generation	(D) System Transmission	(E) Distribution
1	Levelized Income Taxes *	NA	NA	NA	1.98%	1.90%
2	Levelized Property Tax *	NA	NA	NA	1.20%	1.20%
3	Total	NA	NA	NA	3.18%	3.10%
4						
5	Levelized Income & Property Taxes	NA	NA	NA	$31.80	$31.00
6	(per $1,000 of Investment)					
7						
8	Expected Life	20	10	5	57	43
9						
10	Nominal Interest Rate *	8.72%	8.72%	8.72%	8.72%	8.72%
11						
12	Present Value: Income **	NA	NA	NA	$361.68	$345.84
13	Taxes & Property Taxes per				(PV of $31.80 per year	(PV of $31.00 per year
14	$1,000 of Investment				for 57 years at 8.72%)	for 43 years at 8.72%)
15						
16	Removal Cost Per $1,000 Investment				$222.23	$318.15
17						
18	Present Value: Removal Cost				$1.90	$8.75
19	at End of Useful Life				(PV of $222.23 in	(PV of $318.15 in
20					57 years at 8.72%)	43 years at 8.72%)
21						
22	Investment and Taxes	$1,000.00	$1,000.00	$1,000.00	$1,363.58	$1,354.59
23	w/o PVCD (Line 12 + Line 18 + $1000)					
24						
25	PVCD Factor	NA	NA	NA	0.030314	0.054960
26						
27	PVCD $ (Line 22 x Line 25)	NA	NA	NA	$41.34	$74.45
28						
29	Total (Line 22 + Line 27)	$1,000.00	$1,000.00	$1,000.00	$1,404.92	$1,429.04
30						
31	EOY Annual Charge ***	$82.64	$128.50	$224.22	$83.25	$88.78
32						
33	Annual Economic Carrying	8.26%	12.85%	22.42%	8.33%	8.88%
34	Adm &Gen Expense Loading Factor	0.00%	0.00%	0.00%	1.92%	1.92%
35						
36	Annual Econ Carrying + A&G Loading	8.26%	12.85%	22.42%	10.25%	10.80%

Footnotes:

From Financial Analysis -

** PV = Ln(5) x [1/r - (1/r)/(1+r)^a]

31.80*(1/0.0872-(1/0.0872)/(1+0.0872)^57)
31.00*(1/0.0872-(1/0.0872)/(1+0.0872)^43)

Where:
r = Nominal Interest Rate
a = Expected Investment Life

*** The Annual Charge Formula: AC% = Ln(11) x k x {1/[1 - 1/(1+k)^a]}/(1+k)

Where:
k = real interest rate = (1 + r) / (1 + i) - 1
i = inflation rate = 2.5%
a = expected investment life
r = nominal interest rate

Charge 2

PacifiCorp
Oregon Marginal Cost Study
Financial Inputs to the Economic Carrying Charge Calculation

	(A)	(B)	(C)	(D)
	Financial Inputs		Levelized	
1	Weighted Cost of Capital	8.72%	Income Taxes	
2	Borrowing Rate	8.72%	Transmission	1.98%
3	Inflation	2.50%	Distribution	1.90%
4			Property Taxes	
5	Real Cost of Capital		Transmission	1.20%
6	(1+0.0872)/(1+0.0250)-1 =	6.07%	Distribution	1.20%

Source:
WCC - Results of Operations (Oregon)
Inflation Rate - page 358, IRP 2003
Use of Facilities Charge Dec 31, 2003

Charge 3

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.5 & 57 Year Average Life
Page 1 of 2

Real Cost of Capital = 6.07%

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1}-(J)) * 100	(B)	1.0607 ^Year	(C) / (D)	(B)	1.0607 ^57	(F) / (G)	(E) - (H)	(Given)
										100.0000
1	0.000478	5.26%	0.0526	1.060656	0.049622	0.0526	28.691448	0.001834	0.047787	99.9474
2	0.001377	10.53%	0.1053	1.124991	0.093568	0.1053	28.691448	0.003669	0.089899	99.8421
3	0.002222	10.53%	0.1053	1.193229	0.088217	0.1053	28.691448	0.003669	0.084548	99.7368
4	0.003133	12.05%	0.1205	1.265606	0.095246	0.1205	28.691448	0.004201	0.091045	99.6163
5	0.004047	12.88%	0.1288	1.342372	0.095929	0.1288	28.691448	0.004488	0.091440	99.4875
6	0.004907	12.88%	0.1288	1.423796	0.090443	0.1288	28.691448	0.004488	0.085955	99.3588
7	0.005861	15.21%	0.1521	1.510157	0.100698	0.1521	28.691448	0.005300	0.095398	99.2067
8	0.006791	15.79%	0.1579	1.601758	0.098576	0.1579	28.691448	0.005503	0.093073	99.0488
9	0.007666	15.79%	0.1579	1.698914	0.092939	0.1579	28.691448	0.005503	0.087435	98.8909
10	0.008655	19.02%	0.1902	1.801964	0.105567	0.1902	28.691448	0.006630	0.098937	98.7007
11	0.009592	19.19%	0.1919	1.911264	0.100420	0.1919	28.691448	0.006689	0.093731	98.5087
12	0.010491	19.60%	0.1960	2.027194	0.096685	0.1960	28.691448	0.006831	0.089854	98.3127
13	0.011492	23.26%	0.2326	2.150155	0.108193	0.2326	28.691448	0.008108	0.100085	98.0801
14	0.012431	23.26%	0.2326	2.280576	0.102006	0.2326	28.691448	0.008108	0.093898	97.8475
15	0.013357	24.47%	0.2447	2.418906	0.101177	0.2447	28.691448	0.008530	0.092647	97.6027
16	0.014355	28.11%	0.2811	2.565628	0.109545	0.2811	28.691448	0.009796	0.099750	97.3217
17	0.015290	28.11%	0.2811	2.721249	0.103281	0.2811	28.691448	0.009796	0.093485	97.0406
18	0.016235	30.35%	0.3035	2.886309	0.105155	0.3035	28.691448	0.010578	0.094576	96.7371
19	0.017219	33.72%	0.3372	3.061382	0.110144	0.3372	28.691448	0.011752	0.098392	96.3999
20	0.018140	33.72%	0.3372	3.247073	0.103845	0.3372	28.691448	0.011752	0.092093	96.0627
21	0.019094	37.33%	0.3733	3.444028	0.108385	0.3733	28.691448	0.013010	0.095375	95.6895
22	0.020056	40.28%	0.4028	3.652930	0.110270	0.4028	28.691448	0.014039	0.096230	95.2866
23	0.020956	40.28%	0.4028	3.874502	0.103964	0.4028	28.691448	0.014039	0.089924	94.8838
24	0.021904	45.51%	0.4551	4.109514	0.110749	0.4551	28.691448	0.015863	0.094886	94.4287
25	0.022834	47.75%	0.4775	4.358782	0.109559	0.4775	28.691448	0.016644	0.092915	93.9512
26	0.023700	47.75%	0.4775	4.623168	0.103294	0.4775	28.691448	0.016644	0.086650	93.4736
27	0.024631	55.06%	0.5506	4.903592	0.112288	0.5506	28.691448	0.019191	0.093097	92.9230
28	0.025518	56.35%	0.5635	5.201025	0.108346	0.5635	28.691448	0.019640	0.088705	92.3595
29	0.026343	56.35%	0.5635	5.516499	0.102150	0.5635	28.691448	0.019640	0.082509	91.7960
30	0.027241	66.00%	0.6600	5.851108	0.112799	0.6600	28.691448	0.023003	0.089796	91.1360
31	0.028075	66.00%	0.6600	6.206014	0.106348	0.6600	28.691448	0.023003	0.083345	90.4760
32	0.028866	67.64%	0.6764	6.582447	0.102753	0.6764	28.691448	0.023574	0.079179	89.7996
33	0.029700	76.91%	0.7691	6.981712	0.110162	0.7691	28.691448	0.026807	0.083356	89.0305
34	0.030471	76.91%	0.7691	7.405196	0.103863	0.7691	28.691448	0.026807	0.077056	88.2614
35	0.031216	80.58%	0.8058	7.854366	0.102587	0.8058	28.691448	0.028083	0.074503	87.4556
36	0.031975	89.12%	0.8912	8.330782	0.106980	0.8912	28.691448	0.031062	0.075918	86.5644
37	0.032673	89.12%	0.8912	8.836095	0.100862	0.8912	28.691448	0.031062	0.069800	85.6732
38	0.033357	95.30%	0.9530	9.372058	0.101681	0.9530	28.691448	0.033214	0.068467	84.7202
39	0.034034	102.84%	1.0284	9.940531	0.103457	1.0284	28.691448	0.035844	0.067613	83.6918
40	0.034650	102.84%	1.0284	10.543485	0.097541	1.0284	28.691448	0.035844	0.061697	82.6634
41	0.035262	111.98%	1.1198	11.183012	0.100133	1.1198	28.691448	0.039029	0.061104	81.5436
42	0.035845	118.07%	1.1807	11.861330	0.099542	1.1807	28.691448	0.041152	0.058390	80.3629
43	0.036372	118.07%	1.1807	12.580792	0.093850	1.1807	28.691448	0.041152	0.052698	79.1822
44	0.036896	130.68%	1.3068	13.343895	0.097929	1.3068	28.691448	0.045545	0.052384	77.8754
45	0.037379	134.88%	1.3488	14.153284	0.095297	1.3488	28.691448	0.047010	0.048288	76.5266
46	0.037808	134.88%	1.3488	15.011767	0.089848	1.3488	28.691448	0.047010	0.042838	75.1779
47	0.038230	151.30%	1.5130	15.922322	0.095023	1.5130	28.691448	0.052733	0.042290	73.6649
48	0.038603	153.12%	1.5312	16.888109	0.090669	1.5312	28.691448	0.053369	0.037300	72.1337
49	0.038927	154.08%	1.5408	17.912476	0.086016	1.5408	28.691448	0.053701	0.032315	70.5929
50	0.039233	172.18%	1.7218	18.998978	0.090624	1.7218	28.691448	0.060009	0.030614	68.8712
51	0.039487	172.18%	1.7218	20.151382	0.085441	1.7218	28.691448	0.060009	0.025432	67.1494
52	0.039697	175.97%	1.7597	21.373687	0.082331	1.7597	28.691448	0.061333	0.020999	65.3897
53	0.039874	191.16%	1.9116	22.670132	0.084321	1.9116	28.691448	0.066625	0.017696	63.4781
54	0.040003	191.16%	1.9116	24.045214	0.079499	1.9116	28.691448	0.066625	0.012874	61.5665
55	0.040089	197.20%	1.9720	25.503704	0.077322	1.9720	28.691448	0.068731	0.008591	59.5945
56	0.040133	208.42%	2.0842	27.050659	0.077048	2.0842	28.691448	0.072642	0.004406	57.5103
57	0.040133	208.42%	2.0842	28.691448	0.072642	2.0842	28.691448	0.072642	0.000000	55.4261
58	0.040090	215.23%	2.1523	30.431760	0.070725	2.1523	28.691448	0.075015	-0.004290	53.2738
59	0.040004	222.04%	2.2204	32.277632	0.068789	2.2204	28.691448	0.077387	-0.008598	51.0535
60	0.039878	222.04%	2.2204	34.235468	0.064855	2.2204	28.691448	0.077387	-0.012532	48.8331

Charge 4

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R 2.5 & 57 Year Average Life
Page 2 of 2

YEAR	(A) PVCD	(B) % RENEWED	(C) NUM1	(D) DEM1	(E) NUM1/DEM1	(F) NUM2	(G) DEM2	(H) NUM2/DEM2	(I) INSTANCE	(J) Iowa R 2.5
	((A) {yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0607 ^Year	(C) / (D)	(B)	1.0607 ^57	(F) / (G)	(E) - (H)	(Given)
61	0.039712	227.08%	2.2708	36.312059	0.062534	2.2708	28.691448	0.079144	-0.016610	46.5624
62	0.039508	229.79%	2.2979	38.514608	0.059663	2.2979	28.691448	0.080090	-0.020427	44.2645
63	0.039270	229.79%	2.2979	40.850755	0.056251	2.2979	28.691448	0.080090	-0.023839	41.9666
64	0.038999	229.85%	2.2985	43.328604	0.053047	2.2985	28.691448	0.080109	-0.027062	39.6681
65	0.038698	229.86%	2.2986	45.956749	0.050017	2.2986	28.691448	0.080114	-0.030098	37.3695
66	0.038369	229.86%	2.2986	48.744307	0.047156	2.2986	28.691448	0.080114	-0.032958	35.0709
67	0.038024	221.83%	2.2183	51.700948	0.042906	2.2183	28.691448	0.077314	-0.034409	32.8527
68	0.037657	221.40%	2.2140	54.836927	0.040375	2.2140	28.691448	0.077167	-0.036792	30.6386
69	0.037268	219.75%	2.1975	58.163123	0.037781	2.1975	28.691448	0.076590	-0.038809	28.4412
70	0.036887	204.84%	2.0484	61.691073	0.033204	2.0484	28.691448	0.071395	-0.038190	26.3927
71	0.036486	204.84%	2.0484	65.433014	0.031306	2.0484	28.691448	0.071395	-0.040089	24.3443
72	0.036079	199.12%	1.9912	69.401927	0.028691	1.9912	28.691448	0.069401	-0.040710	22.3531
73	0.035692	181.96%	1.8196	73.611579	0.024720	1.8196	28.691448	0.063421	-0.038702	20.5334
74	0.035290	181.96%	1.8196	78.076572	0.023306	1.8196	28.691448	0.063421	-0.040115	18.7138
75	0.034900	171.38%	1.7138	82.812395	0.020695	1.7138	28.691448	0.059733	-0.039038	17.0000
76	0.034535	155.51%	1.5551	87.835474	0.017705	1.5551	28.691448	0.054200	-0.036496	15.4449
77	0.034160	155.51%	1.5551	93.163233	0.016692	1.5551	28.691448	0.054200	-0.037508	13.8898
78	0.033813	140.46%	1.4046	98.814154	0.014214	1.4046	28.691448	0.048954	-0.034740	12.4852
79	0.033488	128.14%	1.2814	104.807838	0.012226	1.2814	28.691448	0.044662	-0.032435	11.2038
80	0.033157	128.14%	1.2814	111.165075	0.011527	1.2814	28.691448	0.044662	-0.033134	9.9224
81	0.032867	109.87%	1.0987	117.907918	0.009318	1.0987	28.691448	0.038292	-0.028974	8.8238
82	0.032593	102.04%	1.0204	125.059756	0.008159	1.0204	28.691448	0.035563	-0.027404	7.8034
83	0.032314	102.04%	1.0204	132.645396	0.007692	1.0204	28.691448	0.035563	-0.027871	6.7831
84	0.032087	81.84%	0.8184	140.691152	0.005817	0.8184	28.691448	0.028526	-0.022708	5.9646
85	0.031867	78.28%	0.7828	149.224932	0.005246	0.7828	28.691448	0.027284	-0.022038	5.1818
86	0.031644	78.28%	0.7828	158.276338	0.004946	0.7828	28.691448	0.027284	-0.022338	4.3990
87	0.031478	57.44%	0.5744	167.876768	0.003421	0.5744	28.691448	0.020019	-0.016598	3.8246
88	0.031310	57.44%	0.5744	178.059522	0.003226	0.5744	28.691448	0.020019	-0.016794	3.2502
89	0.031148	54.81%	0.5481	188.859923	0.002902	0.5481	28.691448	0.019102	-0.016200	2.7022
90	0.031028	39.89%	0.3989	200.315434	0.001992	0.3989	28.691448	0.013905	-0.011913	2.3032
91	0.030908	39.89%	0.3989	212.465793	0.001878	0.3989	28.691448	0.013905	-0.012027	1.9043
92	0.030799	35.77%	0.3577	225.353144	0.001587	0.3577	28.691448	0.012467	-0.010879	1.5466
93	0.030719	26.14%	0.2614	239.022193	0.001094	0.2614	28.691448	0.009111	-0.008017	1.2852
94	0.030638	26.14%	0.2614	253.520353	0.001031	0.2614	28.691448	0.009111	-0.008080	1.0238
95	0.030571	21.78%	0.2178	268.897916	0.000810	0.2178	28.691448	0.007592	-0.006782	0.8059
96	0.030519	16.46%	0.1646	285.208222	0.000577	0.1646	28.691448	0.005736	-0.005159	0.6414
97	0.030467	16.46%	0.1646	302.507847	0.000544	0.1646	28.691448	0.005736	-0.005192	0.4768
98	0.030428	12.29%	0.1229	320.856801	0.000383	0.1229	28.691448	0.004283	-0.003900	0.3539
99	0.030398	9.51%	0.0951	340.318732	0.000279	0.0951	28.691448	0.003314	-0.003035	0.2589
100	0.030367	9.51%	0.0951	360.961148	0.000263	0.0951	28.691448	0.003314	-0.003051	0.1638
101	0.030350	5.46%	0.0546	382.855653	0.000143	0.0546	28.691448	0.001902	-0.001759	0.1092
102	0.030336	4.11%	0.0411	406.078193	0.000101	0.0411	28.691448	0.001431	-0.001330	0.0682
103	0.030323	4.11%	0.0411	430.709323	0.000095	0.0411	28.691448	0.001431	-0.001336	0.0271
104	0.030319	1.14%	0.0114	456.834482	0.000025	0.0114	28.691448	0.000396	-0.000371	0.0157
105	0.030317	0.81%	0.0081	484.544292	0.000017	0.0081	28.691448	0.000281	-0.000265	0.0077
106	0.030314	0.77%	0.0077	513.934871	0.000015	0.0077	28.691448	0.000267	-0.000252	0.0000
		100.0000	100.0000							

Charge 5

PacifiCorp
Oregon Marginal Cost Study
Present Value of Cost of Dispersion Factor
Iowa Curve R1.5 & 43 Year Average Life

Real Cost of Capital = 6.07%

	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
YEAR	PVCD	% RENEWED	NUM1	DEM1	NUM1/DEM1	NUM2	DEM2	NUM2/DEM2	INSTANCE	Iowa R 1.5
	((A){yr-1} +(I)) / 100	((J,{yr-1})-(J)) * 100	(B)	1.0607 ^Year	(C) / (D)	(B)	1.0607 ^43	(F) / (G)	(E) - (H)	(Given)
46	0.076711	210.92%	2.1092	15.011767	0.140502	2.1092	12.580792	0.167651	-0.027149	48.2176
47	0.076353	214.70%	2.1470	15.922322	0.134841	2.1470	12.580792	0.170655	-0.035814	46.0706
48	0.075917	215.28%	2.1528	16.888109	0.127477	2.1528	12.580792	0.171121	-0.043644	43.9177
49	0.075402	217.63%	2.1763	17.912476	0.121495	2.1763	12.580792	0.172984	-0.051489	41.7415
50	0.074818	217.60%	2.1760	18.998978	0.114534	2.1760	12.580792	0.172964	-0.058430	39.5654
51	0.074169	217.12%	2.1712	20.151382	0.107743	2.1712	12.580792	0.172578	-0.064835	37.3943
52	0.073459	217.12%	2.1712	21.373687	0.101581	2.1712	12.580792	0.172578	-0.070996	35.2231
53	0.072705	213.27%	2.1327	22.670132	0.094073	2.1327	12.580792	0.169516	-0.075443	33.0905
54	0.071898	212.84%	2.1284	24.045214	0.088515	2.1284	12.580792	0.169176	-0.080661	30.9621
55	0.071065	206.84%	2.0684	25.503704	0.081101	2.0684	12.580792	0.164407	-0.083306	28.8937
56	0.070194	204.84%	2.0484	27.050659	0.075724	2.0484	12.580792	0.162817	-0.087094	26.8453
57	0.069311	197.92%	1.9792	28.691448	0.068981	1.9792	12.580792	0.157316	-0.088335	24.8662
58	0.068410	193.30%	1.9330	30.431760	0.063520	1.9330	12.580792	0.153649	-0.090129	22.9332
59	0.067504	186.77%	1.8677	32.277632	0.057864	1.8677	12.580792	0.148458	-0.090594	21.0654
60	0.066605	178.79%	1.7879	34.235468	0.052224	1.7879	12.580792	0.142114	-0.089890	19.2775
61	0.065702	173.80%	1.7380	36.312059	0.047862	1.7380	12.580792	0.138143	-0.090282	17.5396
62	0.064834	162.14%	1.6214	38.514608	0.042098	1.6214	12.580792	0.128879	-0.086780	15.9182
63	0.063957	159.43%	1.5943	40.850755	0.039026	1.5943	12.580792	0.126721	-0.087695	14.3239
64	0.063145	144.05%	1.4405	43.328604	0.033245	1.4405	12.580792	0.114497	-0.081252	12.8835
65	0.062313	144.05%	1.4405	45.956749	0.031344	1.4405	12.580792	0.114497	-0.083153	11.4430
66	0.061574	125.35%	1.2535	48.744307	0.025716	1.2535	12.580792	0.099635	-0.073920	10.1895
67	0.060820	125.35%	1.2535	51.700948	0.024245	1.2535	12.580792	0.099635	-0.075390	8.9360
68	0.060150	109.34%	1.0934	54.836927	0.019939	1.0934	12.580792	0.086908	-0.066969	7.8427
69	0.059487	106.51%	1.0651	58.163123	0.018313	1.0651	12.580792	0.084662	-0.066350	6.7775
70	0.058895	93.49%	0.9349	61.691073	0.015154	0.9349	12.580792	0.074310	-0.059156	5.8427
71	0.058331	87.91%	0.8791	65.433014	0.013435	0.8791	12.580792	0.069874	-0.056439	4.9636
72	0.057824	77.88%	0.7788	69.401927	0.011221	0.7788	12.580792	0.061903	-0.050682	4.1848
73	0.057365	69.67%	0.6967	73.611579	0.009465	0.6967	12.580792	0.055382	-0.045916	3.4880
74	0.056947	62.70%	0.6270	78.076572	0.008030	0.6270	12.580792	0.049836	-0.041806	2.8611
75	0.056595	52.23%	0.5223	82.812395	0.006307	0.5223	12.580792	0.041518	-0.035210	2.3387
76	0.056266	48.33%	0.4833	87.835474	0.005502	0.4833	12.580792	0.038412	-0.032910	1.8555
77	0.056014	36.60%	0.3660	93.163233	0.003929	0.3660	12.580792	0.029096	-0.025167	1.4894
78	0.055769	35.34%	0.3534	98.814154	0.003576	0.3534	12.580792	0.028090	-0.024514	1.1360
79	0.055601	23.95%	0.2395	104.807838	0.002285	0.2395	12.580792	0.019040	-0.016754	0.8965
80	0.055432	23.95%	0.2395	111.165075	0.002155	0.2395	12.580792	0.019040	-0.016885	0.6570
81	0.055317	16.22%	0.1622	117.907918	0.001376	0.1622	12.580792	0.012893	-0.011518	0.4948
82	0.055204	15.81%	0.1581	125.059756	0.001265	0.1581	12.580792	0.012570	-0.011305	0.3366
83	0.055124	11.16%	0.1116	132.645396	0.000842	0.1116	12.580792	0.008873	-0.008031	0.2250
84	0.055051	10.00%	0.1000	140.691152	0.000711	0.1000	12.580792	0.007949	-0.007238	0.1250
85	0.055007	6.16%	0.0616	149.224932	0.000413	0.0616	12.580792	0.004897	-0.004484	0.0634
86	0.054977	4.09%	0.0409	158.276338	0.000259	0.0409	12.580792	0.003253	-0.002995	0.0225
87	0.054961	2.09%	0.0209	167.876768	0.000125	0.0209	12.580792	0.001664	-0.001539	0.0015
88	0.054961	0.09%	0.0009	178.059522	0.000005	0.0009	12.580792	0.000074	-0.000069	0.0006
89	0.054960	0.06%	0.0006	188.859923	0.000003	0.0006	12.580792	0.000048	-0.000045	-
			100.0000	44.0012						

CHARGE 6

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 3/31/2002 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount
		$		Yrs	%	$
	TRANSMISSION PLANT					
350.20	Land Rights	54,876,243	R5	70.00	0.00%	-
352.00	Structures & Improvements	45,197,864	R2	65.00	-10.00%	(4,519,786)
353.00	Station Equipment	718,061,371	R1.5	58.00	-5.00%	(35,903,069)
353.70	Supervisory Equipment	40,342,241	R1	20.00	-5.00%	(2,017,112)
354.00	Towers & Fixtures	346,136,577	S6	60.00	-30.00%	(103,840,973)
355.00	Poles & Fixtures	424,474,180	R3	50.00	-30.00%	(127,342,254)
356.00	OH Conductors & Devices	540,424,061	R5	60.00	-40.00%	(216,169,624)
356.20	Clearing	30,346,133	R5	70.00	0.00%	-
357.00	UG Conduit	2,363,978	R2	60.00	-90.00%	(2,127,580)
358.00	UG Conductors & Devices	3,913,828	R2	50.00	-20.00%	(782,766)
359.00	Roads & Trails	10,989,661	R5	70.00	0.00%	-
	Total Transmission Plant	2,217,126,137		57.23	-22.22%	(492,703,164)
				Use 57 Years		

[1] Account Number	[2] Description	[3] 3/31/2002 Balance				
	TRANSMISSION PLANT excludes land accounts					
352.00	Structures & Improvements	45,197,864	2.00	2.09%	0.0418	
353.00	Station Equipment	718,061,371	1.50	33.21%	0.4981	
353.70	Supervisory Equipment	40,342,241	1.00	1.87%	0.0187	
354.00	Towers & Fixtures	346,136,577	-	16.01%	-	
355.00	Poles & Fixtures	424,474,180	3.00	19.63%	0.5889	
356.00	OH Conductors & Devices	540,424,061	5.00	24.99%	1.2497	
356.20	Clearing	30,346,133	5.00	1.40%	0.0702	
357.00	UG Conduit	2,363,978	2.00	0.11%	0.0022	
358.00	UG Conductors & Devices	3,913,828	2.00	0.18%	0.0036	
359.00	Roads & Trails	10,989,661	5.00	0.51%	0.0254	
	Total Transmission Plant	2,162,249,894		100.00%	2.4986	Use R 2.5

PACIFICORP
Remaining Life Depreciation Rates

[1] Account Number	[2] Description	[3] 3/31/2002 Balance	[4] IOWA CURVE	[5] Average Life	[6] NET SALVAGE Percent	[7] NET SALVAGE Amount
		$		Yrs	%	$
	DISTRIBUTION PLANT (OREGON)					
360.20	Land Rights	3,556,253	R4	50.00	0.00%	-
361.00	Structures & Improvements	10,867,743	R2	60.00	-10.00%	(1,086,774)
362.00	Station Equipment	144,719,084	R2	50.00	-30.00%	(43,415,725)
362.70	Supervisory & Alarm Equipment	3,071,319	R3	15.00	0.00%	-
364.00	Poles, Towers & Fixtures	245,988,097	R1.5	38.00	-90.00%	(221,389,287)
365.00	OH Conductors & Devices	192,628,003	R1.5	45.00	-50.00%	(96,314,002)
366.00	UG Conduit	63,050,759	S1	60.00	-40.00%	(25,220,304)
367.00	UG Conductors & Devices	106,484,060	R2.5	45.00	-15.00%	(15,972,609)
368.00	Line Transformers	299,068,104	R1	38.00	0.00%	-
369.10	Overhead Services	48,305,407	R1.5	50.00	0.00%	-
369.20	Underground Services	83,849,378	R2.5	45.00	0.00%	-
370.00	Meters	56,004,340	R1	27.00	0.00%	-
371.00	I.O.C.P.	2,474,569	S-.5	20.00	-5.00%	(123,728)
373.00	Street Lighting & Signal Systems	15,643,963	R1	40.00	-15.00%	(2,346,594)
	Total OREGON Distribution Plant	1,275,711,079		42.68	-31.82%	(405,869,024)
				Use 43 years		

	DISTRIBUTION PLANT excludes land accounts (OREGON)					
361.00	Structures & Improvements	10,867,743	2	0.85%	0.017086	
362.00	Station Equipment	144,719,084	2	11.38%	0.227518	
362.70	Supervisory & Alarm Equipment	3,071,319	3	0.24%	0.007243	
364.00	Poles, Towers & Fixtures	245,988,097	1.5	19.34%	0.290045	
365.00	OH Conductors & Devices	192,628,003	1.5	15.14%	0.227128	
366.00	UG Conduit	63,050,759	0	4.96%	0	
367.00	UG Conductors & Devices	106,484,060	2.5	8.37%	0.209259	
368.00	Line Transformers	299,068,104	1	23.51%	0.235088	
369.10	Overhead Services	48,305,407	1.5	3.80%	0.056957	
369.20	Underground Services	83,849,378	2.5	6.59%	0.164778	
370.00	Meters	56,004,340	1	4.40%	0.044023	
371.00	I.O.C.P.	2,474,569	0	0.19%	0	
373.00	Street Lighting & Signal Systems	15,643,963	1	1.23%	0.012297	
	Total OREGON Distribution Plant	1,272,154,826		100.00%	1.491422	Use R 1.5

Curves:
R=positive
L=negative
S=0

R means right of the standard
L means left of the standard
S is at the standard

Losses

PacifiCorp
Oregon Marginal Cost Study
Energy Loss Factors

Line	(A) Voltage Level	(B) Factor	(C) Loss Percent
1	Transmission Line	1.04543	4.54%
2	(>= 69 kV)		
3			
4			
5			
6	Primary Line	1.06908	6.91%
7	(2.4 kV thru 34.5 kV)		
8			
9			
10			
11	Secondary Distribution	1.09950	9.95%
12	(<= 600 Volts)		

Cust Data 1

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended March 31, 2004 - Actual

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class	(H) Billing Load Factor (D) / 8.76 / (F)
1	Res - Schedule 4	(sec)	429,164	100.0%	5,005,318	100.0%	2,899,344	100.0%	19.71%
2									
3	GS - Schedule 23								
4	0-15 kW	(sec)	58,966	92.1%	630,728	61.0%	300,799	72.5%	23.94%
5	15+ kW	(sec)	5,089	7.9%	402,462	39.0%	114,031	27.5%	40.29%
6	Sec Subtotal		64,055	100.0%	1,033,190	100.0%	414,829	100.0%	
7	Primary	(pri)	27		678		230		33.65%
8	Total		64,082		1,033,868		415,059		28.43%
9									
10	GS - Schedule 28								
11	0-50 kW	(sec)	4,064	47.6%	531,902	27.9%	203,937	10.7%	29.77%
12	51-100 kW	(sec)	2,713	31.8%	550,061	28.9%	147,829	7.7%	42.48%
13	> 101kW	(sec)	1,756	20.6%	823,591	43.2%	184,776	9.7%	50.88%
14	Sec Subtotal		8,533	100.0%	1,905,554	100.0%	1,914,089	28.0%	
15	Primary	(pri)	49		20,141		4,652		49.42%
16	Total		8,582		1,925,695		1,918,741		11.46%
17									
18	GS - Schedule 30								
19	0-300 kW	(sec)	263	32.6%	243,980	19.4%	60,643	20.7%	45.93%
20	301+ kW	(sec)	544	67.4%	1,012,653	80.6%	232,607	79.3%	49.70%
21	Sec Subtotal		807	100.0%	1,256,633	100.0%	293,250	100.0%	
22	Primary	(pri)	47		85,351		19,774		49.27%
23	Total		854		1,341,984		313,024		48.94%
24									
25	LPS - Schedule 48T								
26	1 - 4 MW	(sec)	132	97.8%	744,447	90.8%	158,576	91.2%	53.59%
27	> 4 MW	(sec)	3	2.2%	75,440	9.2%	15,215	8.8%	56.60%
28	Sec Subtotal		135	100.0%	819,887	100.0%	173,791	100.0%	
29	1 - 4 MW	(pri)	54	62.1%	406,979	23.7%	65,607	22.9%	70.81%
30	> 4 MW	(pri)	33	37.9%	1,308,651	76.3%	221,173	77.1%	67.54%
31	Pri Subtotal		87	100.0%	1,715,630	100.0%	286,779	100.0%	
32	Trans	(trn)	1		568,452		104,702		61.98%
33	Total		223		3,103,969		565,272		62.68%
34									
35	Irrigation - Schedule 41 (Average)	(sec)	3,477	100.0%	224,969	100.0%	70,886	100.0%	36.23%
36									
37	Irrigation - Schedule 41 (Annual)	(sec)	8,184						

Source: Pricing Dept. (J. Zhang)
Columns B & D - PacifiCorp, Pricing Department
- File: OR GRC Actual and Forecast kWh's and Present Revenues 04 Revised.xls

PacifiCorp
Oregon Marginal Cost Study
Customers and MWh's
12 Months Ended December 2006 - Normalized

Line	Description	(A) Del. Volt	(B) Average Customers	(C) % Total Class	(D) Annual MWh's	(E) % Total Class	(F) Average Billing kW	(G) % Total Class	(H) Load Factor
1	Res - Schedule 4	(sec)	460,491	100.0%	5,079,177	100.0%	2,942,127	100.0%	19.71%
2									
3	GS - Schedule 23								
4	0-15 kW	(sec)	63,230	92.1%	678,078	61.0%	323,380	72.5%	23.94%
5	15+ kW	(sec)	5,457	7.9%	432,675	39.0%	122,591	27.5%	40.29%
6	Sec Subtotal		68,687	100.0%	1,110,753	100.0%	445,971	100.0%	
7	Primary	(pri)	29		728		247		33.65%
8	Total		68,716		1,111,481		446,218		28.43%
9									
10	GS - Schedule 28								
11	0-50 kW	(sec)	4,643	47.6%	582,614	27.9%	223,381	10.7%	29.77%
12	51-100 kW	(sec)	3,099	31.8%	602,504	28.9%	161,923	7.7%	42.48%
13	> 101kW	(sec)	2,006	20.6%	902,113	43.2%	202,393	9.7%	50.88%
14	Sec Subtotal		9,748	100.0%	2,087,230	100.0%	2,096,980	28.0%	
15	Primary	(pri)	54		22,353		5,163		49.42%
16	Total		9,802		2,109,583		2,102,143		11.46%
17									
18	GS - Schedule 30								
19	0-300 kW	(sec)	312	32.6%	260,390	19.4%	64,721	20.7%	45.93%
20	301+ kW	(sec)	646	67.4%	1,080,762	80.6%	248,252	79.3%	49.70%
21	Sec Subtotal		958	100.0%	1,341,152	100.0%	312,973	100.0%	
22	Primary	(pri)	56		91,525		21,204		49.27%
23	Total		1,014		1,432,676		334,177		48.94%
24									
25	LPS - Schedule 48T								
26	1 - 4 MW	(sec)	138	97.8%	821,613	90.8%	175,013	91.2%	53.59%
27	> 4 MW	(sec)	3	2.2%	82,940	9.2%	16,728	8.8%	56.60%
28	Sec Subtotal		140	100.0%	901,394	100.0%	191,741	100.0%	
29	1 - 4 MW	(pri)	56	62.1%	444,269	23.7%	71,618	22.9%	70.81%
30	> 4 MW	(pri)	35	37.9%	1,428,559	76.3%	241,438	77.1%	67.54%
31	Pri Subtotal		91	100.0%	1,872,828	100.0%	313,056	100.0%	
32	Trans	(trn)	1		614,130		113,115		61.98%
33	Total		232		3,388,352		617,912		62.60%
34									
35									
36	Irrigation - Schedule 41 (Average)	(sec)	3,530	100.0%	206,654	100.0%	65,115	100.0%	36.23%
37									
38									
39	Irrigation - Schedule 41 (Annual)	(sec)	8,338	100.0%	206,654	100.0%	65,115	100.0%	36.23%

Source:
Columns B & D - PacifiCorp, Pricing Department

Cust Data 3

PacifiCorp
Oregon Marginal Cost Study
Customer Class Split between
Three Phase / Single Phase

Line	Customer Class		(A) Voltage Level	(B) Three Phase	(C) Total Customers	(D) Three Phase % of Customers (A) / (B)	(E) Single Phase % of Customers 100% - (C)
1	Res - Schedule 4		(sec)	-	429,164	0.0000%	100.0000%
2							
3	GS - Schedule 23						
4	0-15 kW		(sec)	9,876	58,966	16.7486%	83.2514%
5	15+ kW		(sec)	2,986	5,089	58.6756%	41.3244%
6		Sec Subtotal		12,862	64,055		
7	Primary		(pri)	27	27	100.0000%	0.0000%
8		Total		12,889	64,082	20.1133%	79.8867%
9							
10	GS - Schedule 28						
11	0-50 kW		(sec)	2,965	4,063	72.9756%	27.0244%
12	51-100 kW		(sec)	2,313	2,713	85.2562%	14.7438%
13	> 101kW		(sec)	1,715	1,756	97.6651%	2.3349%
14	-		0	-	-	0.0000%	0.0000%
14		Sec Subtotal		6,993	8,532		
15	Primary		(pri)	49	49	100.0000%	0.0000%
16		Total		7,042	8,581	82.0650%	17.9350%
17							
18	GS - Schedule 30						
19	-			-	-	0.0000%	0.0000%
19	0-300 kW			261	263	99.2395%	0.7605%
20	301+ kW			544	544	100.0000%	0.0000%
21		Sec Subtotal		805	807		
22	Primary			47	47	100.0000%	0.0000%
23		Total		852	854	99.7658%	0.2342%
24							
25	LPS - Schedule 48T						
26	1 - 4 MW		(sec)	132	132	100.0000%	0.0000%
27	1 - 4 MW		(pri)	54	54	100.0000%	0.0000%
28	> 4 MW		(sec)	3	3	100.0000%	0.0000%
29	> 4 MW		(pri)	33	33	100.0000%	0.0000%
30	Trans		(trn)	1	1	100.0000%	0.0000%
31	Total			223	223	100.0000%	0.0000%
32							
33	Irrigation - Schedule 41 (Annual)		(sec)	6,816	8,184	83.2845%	16.7155%
34							
35	TOTAL			27,822	511,088	5.4437%	94.5563%

Cust Data 4

PacifiCorp
Oregon Marginal Cost Study
Customer Load Factors
12 Months Ended December 2006

	(A)	(B)	(C)	(D)	(E)
			12 Month Average Peak Load Factors		
Line	Description	Del. Volt	System	Feeder	Transformer
1	Res - Schedule 4	(sec)	68.69%	60.88%	29.41%
2					
3	GS - Schedule 23				
4	0-15 kW	(sec)	63.78%	65.07%	34.20%
5	15+ kW	(sec)	63.54%	52.58%	57.56%
6	Primary	(pri)	63.61%	55.66%	33.65%
7					
8	GS - Schedule 28				
9	0-50 kW	(sec)	68.64%	63.23%	38.67%
10	51-100 kW	(sec)	73.34%	64.11%	55.16%
11	> 101kW	(sec)	76.39%	71.53%	66.08%
12	Primary	(pri)	75.96%	70.56%	49.42%
13					
14	GS - Schedule 30				
15	0-300 kW	(sec)	70.45%	65.31%	59.65%
16	301+ kW	(sec)	72.72%	67.89%	64.54%
17	Primary	(pri)	72.48%	67.61%	49.27%
18					
19	LPS - Schedule 48T				
20	1 - 4 MW	(sec)	75.94%	71.07%	69.60%
21	1 - 4 MW	(pri)	79.79%	76.29%	56.60%
22	> 4 MW	(sec)	88.09%	88.21%	91.97%
23	> 4 MW	(pri)	86.79%	87.47%	67.54%
24	Trans	(trn)	97.50%	107.58%	61.98%
25					
26	Irrigation - Sch 41	(sec)	69.16%	69.16%	47.05%

Cust Data 5

PacifiCorp
Oregon Marginal Cost Study
Allocation of Uncollectible Expense between Members of Class
12 Months Ended December 2006

Line	Description	(A) Del. Volt	(B) Revenues 2004 Commercial	(C) Revenues 2004 Industrial	(D) Percent of Total Revenues Commercial	(E) Percent of Total Revenues Industrial	(F) Allocated Net Uncollectible Commercial	(G) Allocated Net Uncollectible Industrial	(H) Allocated Net Uncollectible Total
1	Res - Schedule 4	(sec)	0	0	0.00%	0.00%	-	-	3,912,403
2									
3	GS - Schedule 23								
4		(sec)	67,131,142	1,600,849	27.14%	1.45%	100,885	1,134	102,020
5		(pri)	139,337	1,357	0.06%	0.00%	209	1	210
6	Total		$67,270,479	$1,602,206	27.19%	1.45%	101,095	1,135	102,230
7									
8	GS - Schedule 28								
9		(sec)	99,361,830	6,755,417	40.17%	6.12%	149,322	4,787	154,109
10		(pri)	826,468	226,761	0.33%	0.21%	1,242	161	1,403
11	Total		$100,188,298	$6,982,178	40.50%	6.33%	150,564	4,948	155,512
12									
13	GS - Schedule 30								
14		(sec)	45,668,932	16,051,893	18.46%	14.54%	68,632	11,375	80,007
15		(pri)	3,496,406	593,924	1.41%	0.54%	5,254	421	5,675
16	Total		$49,165,338	$16,645,817	19.87%	15.08%	73,886	11,796	85,682
17									
18	LPS - Schedule 48T								
19		(sec)	16,514,053	18,525,260	6.68%	16.78%	24,817	13,128	37,946
20		(pri)	14,239,893	48,760,904	5.76%	44.17%	21,400	34,555	55,955
21		(trn)	0	17,872,987	0.00%	16.19%	-	12,666	12,666
22	Total		$30,753,946	$85,159,151	12.43%	77.14%	46,217	60,349	106,567
23									
24	Irrigation - Schedule 41 (Average)	(sec)	$0	$10,696,753	0.00%	100.00%	-	39,605	39,605
25									
26									
27	Total		$247,378,061	$121,086,105			371,761	117,835	4,401,999

1702 Anderberg Exhibit

Case UE –170
PPL Exhibit 1702
Witness: Karl D. Anderberg

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Karl D. Anderberg

Margin Cost Study Results

January 2006

PacifiCorp
State of Oregon
December 31, 2006 Unbundled Revenue Requirement Allocation by Rate Schedule

Line	Description	Total	(A) Residential	(B) General Service Sch 23	(D)	(E) General Service Sch 28	(I)	(J) General Service Sch 30	(M)	(N) Large Power Service Schedule 48T	(O)	(R)	(S) Sch 41 Irrigation	(T)	(U) Street Lighting
			(sec)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(sec)	(pri)	(trn)	(sec)	(pri)	(sec)
1	**Total Operating Revenues**	$799,952	$389,311	$74,320	$48	$116,436	$1,170	$66,066	$4,401	$38,825	$68,765	$19,309	$17,814	$0	$3,487
2	**MWH**	13,356,592	5,079,177	1,110,753	728	2,087,230	22,353	$1,341,152	91,525	904,553	1,872,828	614,130	206,654	0	25,509
3															
4	**Functionalized 20 Year Full Marginal Costs - Class $**														
5	Generation	$555,681	$216,355	$48,419	$31	$87,279	$899	$56,287	$3,731	$37,305	$73,138	$22,688	$8,785	$0	$763
6	Transmission	$54,931	$21,706	$4,952	$3	$8,618	$88	$5,576	$369	$3,639	$6,961	$2,090	$880	$0	$49
7	Distribution	$286,433	$178,365	$39,958	$15	$27,114	$213	$13,221	$828	$6,718	$6,243	$0	$10,694	$0	$3,065
8	Customer - Billing	$12,411	$10,001	$1,405	$1	$496	$3	$49	$3	$110	$71	$1	$252	$0	$19
9	Customer - Metering	$15,422	$11,422	$2,200	$33	$877	$62	$203	$64	$39	$105	$23	$393	$0	$1
10	Customer - Other	$8,680	$7,185	$939	$0	$282	$2	$53	$3	$54	$35	$0	$118	$0	$9
11	Total	$933,558	$445,034	$97,872	$84	$124,666	$1,267	$75,387	$4,999	$47,864	$86,553	$24,803	$21,122	$0	$3,907
12															
13	**Functional Revenue Requirement Allocation Factors**														
14	**Functionalized 20 Year Full Marginal Costs - Class % of Total**														
15	Generation	100.00%	38.94%	8.71%	0.01%	15.71%	0.16%	10.13%	0.67%	6.71%	13.16%	4.08%	1.58%	0.00%	0.14%
16	Transmission	100.00%	39.52%	9.01%	0.01%	15.69%	0.16%	10.15%	0.67%	6.62%	12.67%	3.81%	1.60%	0.00%	0.09%
17	Distribution	100.00%	62.27%	13.95%	0.01%	9.47%	0.07%	4.62%	0.29%	2.35%	2.18%	0.00%	3.73%	0.00%	1.07%
18	Ancillary Service	100.00%	38.94%	8.71%	0.01%	15.71%	0.16%	10.13%	0.67%	6.71%	13.16%	4.08%	1.58%	0.00%	0.14%
19	Customer - Billing	100.00%	80.58%	11.32%	0.00%	4.00%	0.02%	0.39%	0.02%	0.89%	0.57%	0.01%	2.03%	0.00%	0.16%
20	Customer - Metering	100.00%	74.06%	14.26%	0.21%	5.68%	0.40%	1.31%	0.42%	0.25%	0.68%	0.15%	2.55%	0.00%	0.01%
21	Customer - Other	100.00%	82.78%	10.82%	0.00%	3.25%	0.02%	0.61%	0.04%	0.62%	0.40%	0.00%	1.36%	0.00%	0.10%
22	Embedded DSM - (mWh)	100.00%	38.03%	8.32%	0.01%	15.63%	0.17%	10.04%	0.69%	6.77%	14.02%	4.60%	1.55%	0.00%	0.19%
23	Regulatory & Franchise	100.00%	48.67%	9.29%	0.01%	14.56%	0.15%	8.26%	0.55%	4.85%	8.60%	2.41%	2.23%	0.00%	0.44%
24	Taxes (Revenue)														
25															
26	**Functionalized Class Revenue Requirement - (Target)**														
27	Generation	$461,034	$179,504	$40,172	$26	$72,413	$746	$46,699	$3,096	$30,951	$60,681	$18,824	$7,289	$0	$633
28	Transmission	$60,933	$24,078	$5,493	$4	$9,560	$97	$6,185	$410	$4,036	$7,721	$2,319	$976	$0	$54
29	Distribution	$219,443	$136,649	$30,613	$12	$20,772	$163	$10,129	$634	$5,146	$4,783	$0	$8,193	$0	$2,348
30	Ancillary Services	$10,569	$4,115	$921	$1	$1,660	$17	$1,071	$71	$710	$1,391	$432	$167	$0	$15
31	Customer - Billing	$22,800	$18,373	$2,581	$1	$912	$5	$90	$5	$203	$131	$1	$463	$0	$35
32	Customer - Metering	$23,211	$17,191	$3,311	$50	$1,319	$93	$305	$97	$58	$158	$35	$591	$0	$2
33	Customer - Other	$9,436	$7,811	$1,021	$0	$306	$2	$57	$3	$59	$38	$0	$128	$0	$10
34	Embedded DSM - (mWh)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
35	Regulatory & Franchise T	$17,961	$8,741	$1,669	$1	$2,614	$26	$1,483	$99	$872	$1,544	$434	$400	$0	$78
36	Total	$825,386	$396,462	$85,780	$94	$109,557	$1,150	$66,019	$4,415	$42,035	$76,447	$22,044	$18,207	$0	$3,176
37															
38	**Ratio of Operating Revenue to Rever**	96.92%	98.20%	86.64%	51.45%	106.28%	101.70%	100.07%	99.68%	92.36%	89.95%	87.59%	97.84%	#DIV/0!	109.77%
39	(Line 1 / Line 36)														
40															
41	**Increase or (Decrease)**	$25,435	$7,151	$11,459	$46	($6,878)	($20)	($47)	$14	$3,210	$7,682	$2,735	$393	$0	($310)
42	(Line 36 - Line 1)														
43															
44															
45	**Percent Increase (Decrease)**	3.18%	1.84%	15.42%	94.38%	-5.91%	-1.67%	-0.07%	0.32%	8.27%	11.17%	14.17%	2.21%	#DIV/0!	-8.90%
46	(Line 41 / Line 1)														

PPL/1702
Anderberg/1

Func Rev Req - earned

PacifiCorp
Oregon Marginal Cost Study
December 31, 2006 Functionalized Revenue - Earned
($ 000)

Line No.	Description	A Generation	B Transmission	C Distribution	D Ancillary	E C Billing	F C Metering	G C Other	H DSM	I Franchise Fees	J Total
1	Earned Functional Revenue Requirement	$459,552	$57,411	$214,123	$10,772	$22,986	$23,263	$9,519	$0	17,729	$815,356
2											
3	Percent of Total	56.36%	7.04%	26.26%	1.32%	2.82%	2.85%	1.17%	0.00%	2.17%	100.00%
4											
5	Revenue From Classes Included in MC Study	$450,870	$56,327	$210,078	$10,568	$22,552	$22,823	$9,339	$0	$17,394	$799,952
6											
7	Other Revenues										
8	Partial Requirements - Sch. 36 pri (to 23 pri)										$0
9	Partial Requirements - Sch. 36 pri (to 28 pri)										$58
10	Partial Requirements - Sch. 36 pri (to 30 pri)										$294
11	Partial Requirements - Sch. 47 pri										$7,238
12	Partial Requirements - Sch. 47 trn										$3,650
13	USBR Billed Revenue										$604
14	USBR Imputed Revenue										$7,105
15	AGA										$1,404
16	Lighting										$3,067
17	Employee Discount										($397)
18	Total Oregon Situs Revenue										$822,975
19											
20	Special Contracts										$0
21	Removal of USBR Imputed Revenue										($7,105)
22	Total Oregon Revenue										$815,871

Func Rev Req - target

PacifiCorp
Oregon Marginal Cost Study
December 31, 2006 Functionalized Revenue - Target
($ 000)

Line No.	Description	A Generation	B Transmission	C Distribution	D Ancillary	E C Billing	F C Metering	G C Other	H DSM	I Franchise Fees	J Total	
1	Target Functional Revenue Requirement	469,884	62,103	223,655	10,772	23,238	23,657	9,617	0	18,306	$841,231	
2												
3	Percent of Total	55.86%	7.38%	26.59%	1.28%	2.76%	2.81%	1.14%	0.00%	2.18%	100.00%	
4												Increase
5	Revenue From Classes Included in MC Study	$461,034	$60,933	$219,443	$10,569	$22,800	$23,211	$9,436	$0	$17,961	$ 825,386	$25,435
6												
7	Other Revenues											25,875
8	Partial Requirements - Sch. 36 pri (to 23 pri)										$1	$0
9	Partial Requirements - Sch. 36 pri (to 28 pri)										$48	-$10
10	Partial Requirements - Sch. 36 pri (to 30 pri)										$243	-$50
11	Partial Requirements - Sch. 47 pri										$7,636	$398
12	Partial Requirements - Sch. 47 trn										$4,049	$399
13	USBR Billed Revenue										$604	$0
14	USBR Imputed Revenue										$7,105	$0
15	AGA										$1,404	$0
16	Lighting										$2,779	-$288
17	Employee Discount										($404)	($8)
18	Total Oregon Situs Revenue										$848,850	25,435
19												
20	Special Contracts										$0	
21	Removal of USBR Imputed Revenue										($7,105)	
22	Total Oregon Revenue										$841,746	

PPL/1702
Anderberg/3

1800 Smith

Testimony

Case UE-170
PPL Exhibit 1800
Witness: Mark H. Smith

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Mark H. Smith

Value

January 2006

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark H. Smith. My business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232. My present position is Planning Director of Resource Planning.

Qualifications

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Science degree in Geography from Portland State University. I have been employed by PacifiCorp in Portland, Oregon since 1981. Since that time I have held a variety of positions including Hydro Scheduling, Resource Planning, and Power System Modeling, working for the majority of my career in the field of hydroelectric generation and water management. I have been in my current position as a Planning Director since October 2001.

Q. What are your responsibilities as Planning Director?

A. I am currently responsible for daily power generation scheduling, long range generation planning, and water management with respect to PacifiCorp's Hydroelectric projects, including the Klamath Hydroelectric Project. I am responsible for operational and water management decisions that include: PacifiCorp's commitment to resource stewardship; PacifiCorp's obligation to minimize generation costs to customers; PacifiCorp's ability to satisfy minimum flow requirements below Iron Gate Dam; PacifiCorp's obligation to operate Lake Ewauna within contractually obligated elevations; and PacifiCorp's obligation to operate Upper Klamath Lake during high runoff conditions. In addition, I am the

1 primary contact with the U.S. Bureau of Reclamation ("USBR") and other federal
2 and state resource agencies with respect to operations of the Klamath River in
3 conjunction with the Klamath Hydroelectric Project.

4 **Purpose of Testimony**

5 **Q. What is the purpose of your testimony?**

6 A. My testimony is in response to the Commission's Order No. 05-726 in UE-171
7 and the issues list adopted in the August 17, 2005 Ruling in this case.
8 Specifically, I will address changed circumstances related to the 1956 contract
9 with the U.S. Bureau of Reclamation, and the issue of value, asserted by the
10 irrigators, to the Company of irrigation pumping in the Upper Klamath River
11 Basin (the Basin). I explain that whatever value to the Company and its
12 customers that might have existed in the past from the Klamath Irrigation Project
13 has been largely diminished or eliminated as a result of United States Bureau of
14 Reclamation and Klamath Irrigation Project water management policies, practices
15 and requirements associated with (1) Endangered Species Act (ESA)
16 requirements, (2) Tribal Trust requirements, (3) irrigation needs, and (4) ensuring
17 full delivery of water to agricultural users.

18 **Background**

19 **Q. Please briefly describe the Company's hydroelectric operations in the Basin.**

20 A. The Company operates seven hydroelectric generating facilities along
21 approximately 65 miles of the Klamath River from the Link River Dam at Upper
22 Klamath Lake to the Iron Gate Dam. The Link River Dam is the point of
23 diversion for the Eastside and Westside Developments, which are owned and

1 operated by PacifiCorp and are part of the Klamath Hydroelectric Project.
2 However, the Company is not seeking relicensing of the Westside and Eastside
3 plants at the Link River Dam above Keno. Water for the USBR Klamath
4 irrigation project is diverted by USBR from Upper Klamath Lake through the "A-
5 canal," just upstream of the Link River Dam.
6 Generation from the five facilities below Keno obviously varies, but the
7 average over the last forty-two years has been approximately 735,000 MWh's
8 annually. The diagram attached as PPL Exhibit 1801 depicts in a very simple
9 manner the dams and generation facilities along the Klamath River, from Upper
10 Klamath Lake to Iron Gate.
11 **Q. Have you read Doug Larson's direct testimony in this case regarding the**
12 **Company's plans to move Klamath River Basin irrigators to standard tariff**
13 **rates?**
14 A. Yes, I have.
15 **Q. Are you familiar with the two contracts to which he refers, the USBR and**
16 **UKRB contracts?**
17 A. Yes. Both contracts were entered into by the California Oregon Power Company,
18 or "Copco," a predecessor of PacifiCorp. The USBR, or "On-project" contract
19 was entered into with the U.S. Bureau of Reclamation and allowed for the
20 Company's operation of the Link River Dam in a particular manner, and also
21 provides for discounted rates for electric service for irrigation pumping on
22 "Project Land." "Project Land" is essentially land in the Basin lying within a
23 public district or service area of an association, and land of individuals or

1 corporations in the Basin, which have contracted with the United States, pursuant
2 to federal reclamation laws, for water service. The UKRB, or "Off-project"
3 contract was entered into with the Klamath Basin Water Users Protective
4 Association (the "Association") and provides for discounted rates for certain
5 electric service for irrigation of "off-project" land within the boundaries of the
6 Basin.

7 **Q. And with respect to Mr. Larson's statement that "Both USBR and UKRB**
8 **prices were premised on the value provided by the Klamath irrigation**
9 **project to Klamath hydroelectric generation, and hence to the utility's other**
10 **customers," please describe the "value" which has historically been**
11 **recognized from the project.**

12 A. The benefit or value received by the Company and its customers has been
13 described in various manners. With regard to the USBR Contract, which was
14 required under the Company's original license for the Project issued in 1954, the
15 Company received the continued ability to operate the Link River Dam in a
16 certain manner that allowed it to enhance generation downstream, although there
17 were still constraints on the Company. What the Company received in exchange
18 for the discounted rates in the UKRB Contract has been described as the
19 withdrawal by the Association of its objections to the proposed USBR Contract in
20 1955 (*See* November 1955 Agreement, submitted with PacifiCorp's Motion for
21 Summary Disposition in UE 171). Consideration for the discounted rates in the
22 UKRB Contract was alternatively described as "increased flow of water caused by
23 the development of lands for agricultural purposes within the Upper Klamath

1 River Basin, which increased flow will be used for the generation of electric
2 power in Copco's proposed dam improvements on the Klamath River below
3 Keno," as reflected in the April 30, 1956 Agreement between Copco and the
4 Association.

5 **Q. Turning first to the USBR Contract, does the Company still have the same**
6 **operational flexibility for the Link River Dam as it had in 1956?**

7 A. Not at all. By 1997, the Company had lost much or all of the discretion it had in
8 its operation of the Dam, and proposed rescinding the USBR Contract for
9 operation of the Dam. However, the Company and the Bureau instead entered
10 into a Temporary Modification of the USBR Contract in June 1997, providing that
11 the Company would continue to operate the Dam, but would turn over
12 discretionary responsibility for specifying Klamath River flow and Upper Klamath
13 Lake elevations as contained in the Bureau's 1997 Operations Plan for the
14 Klamath Project. In that Temporary Modification, the Bureau recognized:

15 "In recent years, . . . it has become evident that the water supply in the
16 Klamath Basin cannot always meet the needs of the species listed pursuant to the
17 Endangered Species Act (ESA), Tribal trust resources, irrigated agriculture, and
18 wildlife refuges. As a result, PacifiCorp's ability to exercise its discretion in
19 operating Link River Dam for power purposes has been restricted. In addition, the
20 most recent listing of the Coho salmon under the ESA by the National Marine
21 Fisheries Service has caused Reclamation to review its Klamath Project
22 operations."
23

24 The Company and the Bureau have extended the Temporary Modification from
25 year-to-year since 1997, except that the extensions related to the then-current
26 operating plans rather than the 1997 plan. Under those operating plans, the
27 Bureau has specified Klamath River flows and Upper Klamath Lake levels so as

1 to severely limit the Company's operational flexibility and essentially eliminate
2 any enhanced generation capability originally obtained under the 1956 USBR
3 Contract. For instance, because of need to follow USBR directions regarding lake
4 levels and flow rates, the option to use water for hydroelectric production in high
5 electricity demand months or to store water in low demand months is not
6 consistently available to PacifiCorp.

7 **Q. And with regard to the UKRB Contract, does the Company receive some**
8 **quantified value in return for providing discounted rates to the Off-project**
9 **irrigators?**

10 A. I'll answer that with respect to each of the two benefits or considerations that I
11 referred to above. First, as to the Association withdrawing its objections to the
12 USBR Contract, to the extent that was a benefit, it was done fifty years ago, and
13 the benefit will go away at the time the USBR Contract expires. As to the
14 "enhanced flow" consideration recited in the April 1956 Agreement, I think it is
15 first appropriate to look at just what the Association was agreeing to provide in
16 exchange for the discounted rates. When I look at the April 1956 Agreement, I
17 don't see an obligation on the part of the Association to do anything, let alone
18 provide any amount of enhanced or return flow. The Association even
19 recognized, in 1954 when it was seeking discounted rates for its irrigators, that
20 there might be no return flow, stating in a letter to the Hydroelectric Commission
21 of Oregon the Association's position that lower power rates should be available
22 for those "having State water rights as long as the return flow from their lands, *if*
23 *any*, would return to the Klamath River above Keno." (Minutes of Klamath Basin

1 Water Users Protective Association, June 25, 1954; produced in discovery by
2 KWUA, doc.00213; emphasis added). Also, we must consider the source of any
3 enhanced or return flow. Thus, in order to ascribe any value to enhanced or return
4 flow, we need to assume not only that there will be such flow, but also that the
5 flow to which we ascribe value is flow that would not have occurred *but for* the
6 discounted rates. Otherwise, we'd be giving the irrigators something (discounts)
7 for nothing. Further, we would need to assume that any such incremental flow is
8 not offset by reduced flow in the River as a result of increased irrigation, since as I
9 noted above, the water for the irrigation project is diverted from the Klamath
10 River upstream from the Link River Dam. Given those assumptions, and other
11 assumptions and variables that must be considered when trying to determine the
12 level of any value of irrigation at discounted electric rates, the task of quantifying
13 value with any degree of reliability is extremely difficult, if not impossible. This
14 would likewise be the case for On-project irrigation.

15 **Q. Can you briefly describe the hydrology of the Klamath River Hydroelectric**
16 **Project and how the Klamath Irrigation Project affects PacifiCorp**
17 **operations?**

18 A. Yes. The hydrology of the Klamath River project has two distinctly different
19 characteristics. In the upper basin, inflow to Upper Klamath Lake is relatively
20 stable, but can be affected with a large variability of flow due to heavy rainfall or
21 rapid snow melt. In the lower basin (hydroelectric project), increases in flow
22 below JC Boyle tend to be much more volatile with large and frequently rapid
23 fluctuations resulting from heavy rain.

1 Also, the Klamath irrigators have the ability to move water around large areas of
2 the basin. Return or enhanced flow could originate from surface water sources
3 such as the Williamson River, ground water pumping, or as surface runoff. To my
4 knowledge, water diverted to and from the Klamath River is not comprehensively
5 measured, nor is it strictly accounted for.
6 Finally, it should also be mentioned that much of the inflow variability to/from the
7 irrigation project has detrimental effects on PacifiCorp's generation schedules and
8 water management objectives. The hydroelectric project acts as a buffer of large
9 inflow fluctuations introduced by the irrigation project, while PacifiCorp is
10 responsible to maintain strict ramping rates introduced in 1997 (i.e., the rates of
11 increase or decrease in flow) in Link River and the Klamath River below Iron
12 Gate Dam that were not considered in the 1956 contract. The result of this
13 buffering is lack of certainty and predictability of power generation schedules
14 which creates production and financial risk for PacifiCorp. Significant hydrologic
15 variability can be attributed to inflow or withdrawal of water from the Lake
16 Ewauna reach of the Klamath River above Keno Dam. Withdrawals can reach
17 approximately 500-750 cfs during the peak irrigation season, while inflows can
18 reach as high as approximately 3,500 cfs. These flows can change rapidly, and
19 frequently exceed allowable ramping criteria below Link River Dam and Iron
20 Gate. PacifiCorp must modify its operations (generation output) to remain in
21 compliance with ramping guidelines established by the US Fish & Wildlife
22 Service and NOAA Fisheries as part of the Biological Opinions.

1 **Q. Has the Company attempted to determine the value of return or enhanced**
2 **flow, whether from On-project or Off-project irrigation?**
3 A. The Company has been unable to develop a reliable mechanism that could be
4 objectively employed to quantify and attribute incremental hydroelectric
5 production value that may be provided to Klamath operations through the specific
6 action of Klamath Basin irrigators and/or the Bureau, let alone what value could
7 be attributed to the provision of discounted electric rates. One challenge in doing
8 so has been to differentiate incremental changes in value from the underlying
9 hydroelectric production values that might occur naturally (that is, due simply to
10 basin hydrology). The most significant return or enhanced flows typically occur at
11 a time when the project is experiencing surplus flow in the Klamath River
12 resulting in water spilled past project generation facilities. However, as recently
13 as this past water year which ended September 30, 2005, US Geological Survey
14 streamflow records showed that there had been a net loss of water from the river
15 between Link River and Keno Dam (Lake Ewauna).
16 Since 1997, and as ESA requirements have increasingly constrained
17 PacifiCorp's operations, it has become increasingly difficult to consider any
18 inflow from the irrigation project to as providing a positive value. While it's true
19 some of the water does produce generation, that same water can create operational
20 and financial risk and can disrupt generation schedules.
21 I have to say that we have no definitive evidence that providing discounted rates
22 to irrigators in the Basin now provides value to the Company's hydroelectric
23 operations. The potential uncertainty introduces increased risk that must be

1 mitigated by the Company's hydroelectric system downstream from the irrigators.

2 **Q. Do the Klamath Irrigators provide any flexibility to the Company in its**
3 **operation of the Klamath hydroelectric plants?**

4 A. No.

5 **Q. Even if it were established, under the Company's current operating**
6 **parameters, that there is some value in providing discounted rates to the**
7 **irrigators in the Basin, is there any assurance that such value would**
8 **continue?**

9 A. No. Any determination of value would be based on quite a number of variables,
10 and changes in those variables will obviously change the value, potentially
11 eliminating it or creating a negative value, or detriment. One of the biggest
12 sources of variables right now is the Company's relicensing proceeding at FERC.
13 Assuming FERC issues a new license, we do not know the conditions that FERC
14 will attach to the license. At the least, based upon stakeholder discussions to date,
15 we anticipate increased bypass flow requirements at the JC Boyle and Copco No.
16 2 dams, and more restrictive ramp rates. These conditions will reduce value of
17 generation at the Klamath Project facilities.

18 **Q. If you were able to determine a current value of increased flow due to**
19 **irrigation practices in the Basin, assuming such increased flow was found to**
20 **exist, would that value remain constant from year to year?**

21 A. No. As I said above, a determination of value is based on many variables, and
22 many of those variables will change from year to year. For instance, the cost of
23 power in the wholesale market will not remain constant, and while we can use a

forecast for estimating value, one thing that is virtually certain is that the forecast will not precisely match actual market prices in years to come. Similarly, natural stream flows and levels of irrigation pumping will vary from month to month and year to year.

Q. Does this conclude your testimony?

A. Yes it does.

1801 Smith
Exhibit

Case UE –170
PPL Exhibit1801
Witness: Mark H. Smith

BEFORE THE PUBLIC UTILITY COMMISSION

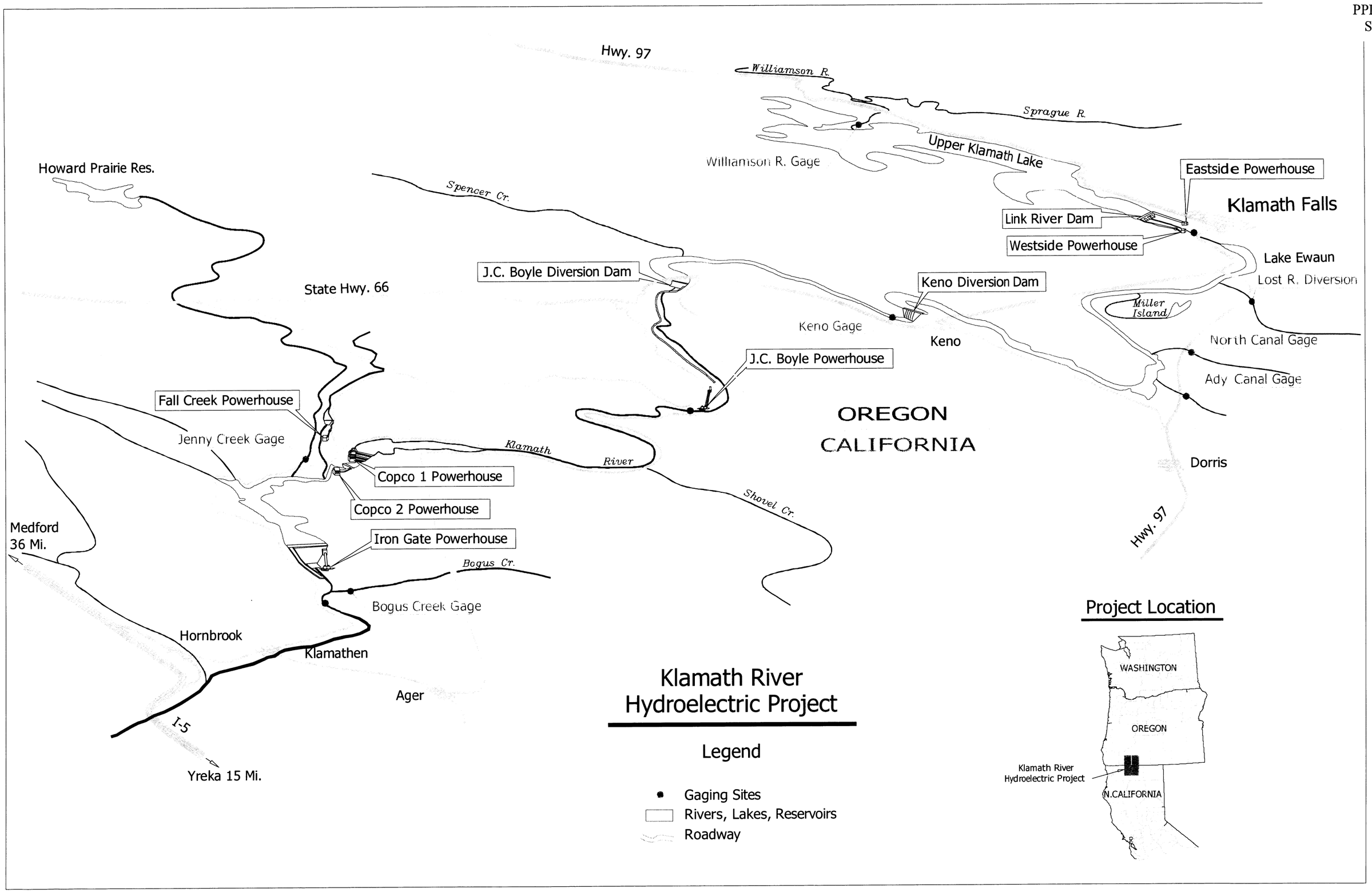
OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Mark H. Smith

Map of Klamath River Hydroelectric Project

January 2006


Hwy. 97
Williamson R.
Sprague R.
Upper Klamath Lake
Williamson R. Gage
Eastside Powerhouse
Klamath Falls
Link River Dam
Westside Powerhouse
Lake Ewaun
Lost R. Diversion
Howard Prairie Res.
Spencer Cr.
J.C. Boyle Diversion Dam
Keno Diversion Dam
State Hwy. 66
Miller Island
Keno Gage
Keno
North Canal Gage
J.C. Boyle Powerhouse
Ady Canal Gage
Fall Creek Powerhouse
OREGON
CALIFORNIA
Jenny Creek Gage
Klamath River
Dorris
Copco 1 Powerhouse
Copco 2 Powerhouse
Shovel Cr.
Medford
36 Mi.
Iron Gate Powerhouse
Hwy. 97
Bogus Cr.
Bogus Creek Gage
Hornbrook
Klamathen
Ager
I-5
Yreka 15 Mi.
Klamath River
Hydroelectric Project
Legend
Gaging Sites
Rivers, Lakes, Reservoirs
Roadway
Project Location
WASHINGTON
OREGON
Klamath River
Hydroelectric Project
N.CALIFORNIA