Puget Sound Power & Light Company
Docket No. UE-920499
Revised and Updated Response to Bench Request No. 5 ("No. 5A")

Request

Provide the calculations of marginal costs in all rates incorporating marginal costs.

Response by Mr. Hoff

The company used estimates of marginal cost to develop the tail block of the residential rate (schedule 7) and the voluntary large power rates (schedules 30 and 48). In addition, marginal costs were used to estimate the benefits from having a customer on interruptible rates (schedules 36, 38, and 39).

Attachment I shows the derivation of the schedule 30 and 48 rates filed in the alternative proposal in Docket No. UE-921262. Table 1 shows the avoided cost allocated to energy and demand using the 84/16 peak credit which is consistent with the cost-of-service study in Docket No. UE-921262. This table is the basis of the marginal cost calculations. Table 2 levelizes the avoided cost using a ten year horizon. The marginal production costs are adjusted for each schedule using the loss factors shown in Table 3. The losses adjusted marginal cost are used in the tail blocks shown in Table 4. The first block rates are set so that the weighted average rate of the two blocks equals the flat rate in the associated schedule (31/49).

Attachment II shows the derivation of the marginal cost tail block for schedule 7. The marginal production costs, from Puget Power's avoided cost, are shown in Table 6. These marginal costs are applied to the water heat load shape and the loss adjustment factors shown in Table 5. The result is the table of summer and winter combined energy and demand costs shown in the last two columns in Table 7. These numbers are levelized using a twelve year time horizon, the typical life of a water heater.

Attachment III shows the derivation of the value of large power interruptions based upon a one and five year estimate of marginal costs. The one year marginal cost is based upon the peak capacity contract with San Diego Gas and Electric and the calculations are shown in lines 1 - 8. The thirty year marginal cost is based upon the assumptions used to value capacity in the peak credit method. These costs are shown in line 9. The five year marginal cost of capacity is assumed to be 1/4 of the way between the one and thirty year capacity values. This calculation is shown in lines 10-12. The remainder of the worksheet shows the application of these marginal costs to the large power interruptible rate design filed in the alternative rate proposal in Docket No. UE-921262.

	Year	Winter Energy mills/kWh	Summer Energy mills/kWh	Capacity Component $/kW Mon	Total Cost $/MWH
1	1992	29.01	24.12	3.75	32.10
2	1993	24.15	20.08	0.00	22.44
3	1994	26.06	21.67	0.00	24.22
4	1995	27.33	22.72	0.00	25.40
5	1996	47.53	39.51	6.14	52.58
6	1997	50.50	41.98	6.53	55.87
7	1998	53.75	44.68	6.94	59.46
8	1999	57.29	47.63	7.40	63.38
9	2000	61.17	50.85	7.90	67.67
10	2001	63.46	52.76	8.20	70.21
11	2002	65.98	54.85	8.53	72.99
12	2003	68.56	57.00	8.86	75.85
13	2004	71.27	59.25	9.21	78.85
14	2005	74.12	61.62	9.58	82.00
15	2006	77.10	64.10	9.96	85.30
16	2007	80.29	66.75	10.38	88.83
17	2008	83.72	69.60	10.82	92.62
18	2009	87.32	72.59	11.28	96.60
19	2010	91.09	75.73	11.77	100.78
20	2011	95.06	79.03	12.28	105.17

Based Upon September, 1992 RFP For Resources. Modifed for 16% Peak Credit

Table 2. Marginal Cost - Levelized Avoided Cost (Base Year 1992)

Time Frame	Winter $/kWh	Summer $/kWh	$ / kW - month
10	0.04025	0.03346	3.98

Table 3. Loss Factors (Used to adjust marginal energy and demand costs.)

Schedule	Energy	Demand
31	5%	7%
49	3%	4%

Table 4. marginal Rate Calculations for Schedules 30 & 48

Rate	Block Factor	Block (1)	Block 2 - Winter $ / kWh	Block 2 - Summer $ / kWh	Block 1 $ /kW	Block 2 $ /kW
49	none		0.031225	0.028386	3.28	3.28
48	75%	0.027087	0.041458	0.034464	2.99	4.14
31 (a)	none		0.035405	0.032186	5.01	5.01
30 (b)	75%	0.032161	0.042263	0.035133	4.78	5.70

(a) Demand rate is class weighted average summer / winter demand

(b) Demand tail block set above marginal cost in order to have an inverted demand rate
$1.44 adder based upon marginal distribution cost of $17.30 /kW-year from marginal cost distribution model

Table 5. Typical End-Use Load Shapes

	Water Heat Load kWh	kW
Jan	452	1.259
Feb	403	1.32
March	418	1.247
April	383	1.242
May	377	1.177
June	347	0.977
July	325	0.73
August	314	0.739
September	331	1.091
October	365	1.141
November	391	1.151
December	436	1.274
Seasonal Totals		
Summer	2077	1.242
Winter	2465	1.32

Energy Losses	8.00%
Demand Losses	12.00%
Discount Rate	10.00%

Table 6. Firm Power Avoided Cost In Latest Bid Package - Peak Credit 16%

	Year	Winter $/mWh	Summer $/mWh	Capacity $/kW-mon	Total $/mWh
1	1992	29.01	24.12	3.75	32.10
2	1993	24.15	20.08	0.00	22.44
3	1994	26.06	21.67	0.00	24.22
4	1995	27.33	22.72	0.00	25.40
5	1996	47.53	39.51	6.14	52.58
6	1997	50.50	41.98	6.53	55.87
7	1998	53.75	44.68	6.94	59.46
8	1999	57.29	47.63	7.40	63.38
9	2000	61.17	50.85	7.90	67.67
10	2001	63.46	52.76	8.20	70.21
11	2002	65.98	54.85	8.53	72.99
12	2003	68.56	57.00	8.86	75.85
13	2004	71.27	59.25	9.21	78.85
14	2005	74.12	61.62	9.58	82.00
15	2006	77.10	64.10	9.96	85.30
16	2007	80.29	66.75	10.38	88.83
17	2008	83.72	69.60	10.82	92.62
18	2009	87.32	72.59	11.28	96.60
19	2010	91.09	75.73	11.77	100.78
20	2011	95.06	79.03	12.28	105.17

Table 7. Water Heat Customer Marginal Costs

Year	Winter Energy $	Summer Energy $	Annual Capacity $	Total	$/ kWh	Winter Capacity $	Summer Capacity $	Winter Total	Summer Total	Winter $ /kWh	Summer $/kWh
1992	$77.23	$54.11	$66.53	$197.86	0.043563	$35.23	$31.30	$112.46	$85.40	0.045623	0.041119
1993	$64.28	$45.03	$0.00	$109.32	0.024068	$0.00	$0.00	$64.28	$45.03	0.026079	0.021681
1994	$69.38	$48.60	$0.00	$117.99	0.025977	$0.00	$0.00	$69.38	$48.60	0.028147	0.023401
1995	$72.76	$50.97	$0.00	$123.73	0.027242	$0.00	$0.00	$72.76	$50.97	0.029519	0.024541
1996	$126.53	$88.63	$108.95	$324.11	0.071358	$57.70	$51.26	$184.22	$139.89	0.074735	0.067352
1997	$134.44	$94.18	$115.77	$344.39	0.075823	$61.31	$54.46	$195.75	$148.64	0.079411	0.071566
1998	$143.08	$100.23	$123.21	$366.52	0.080696	$65.24	$57.96	$208.33	$158.19	0.084513	0.076165
1999	$152.51	$106.84	$131.33	$390.68	0.086016	$69.55	$61.79	$222.06	$168.62	0.090085	0.081186
2000	$162.84	$114.07	$140.22	$417.13	0.091838	$74.25	$65.97	$237.09	$180.04	0.096183	0.086681
2001	$168.95	$118.35	$145.48	$432.78	0.095285	$77.04	$68.44	$245.99	$186.79	0.099793	0.089935
2002	$175.64	$123.04	$151.24	$449.92	0.099058	$80.09	$71.15	$255.73	$194.19	0.103744	0.093496
2003	$182.52	$127.86	$157.17	$467.55	0.102939	$83.23	$73.94	$265.75	$201.80	0.107809	0.097159
2004	$189.74	$132.91	$163.39	$486.04	0.107011	$86.52	$76.87	$276.26	$209.78	0.112073	0.101002
2005	$197.32	$138.22	$169.91	$505.46	0.111286	$89.98	$79.94	$287.30	$218.16	0.116551	0.105037
2006	$205.26	$143.79	$176.75	$525.80	0.115764	$93.60	$83.15	$298.86	$226.94	0.121241	0.109264
2007	$213.76	$149.74	$184.07	$547.56	0.120555	$97.47	$86.60	$311.23	$236.33	0.126258	0.113786
2008	$222.88	$156.13	$191.92	$570.92	0.125698	$101.63	$90.29	$324.51	$246.42	0.131645	0.118641
2009	$232.45	$162.84	$200.17	$595.46	0.131100	$106.00	$94.17	$338.45	$257.01	0.137302	0.123739
2011	$242.51	$169.88	$208.83	$621.22	0.136773	$110.58	$98.24	$353.10	$268.13	0.143244	0.129093

Levelized Cost - 1992 Base

12 Years					0.060					0.063246	0.056354

Large Power Interruptible Rates - Alternative Proposal

San Diego Contract Model

Line	Item	Calculation	Cost
1	Escallation Rate 1991 - 1993		5.60%
2	Contract Cost / kW-Month		2.00
3	Number of Months (Nov - Feb)		4.00
4	Annual Capacity Cost	(L1*L2*L3)	8.45
5	Energy Cost (mills/kWh)		36
6	Wheeling Cost (mills/kWh)		4
7	Total Energy Cost (mills/kWh)	(L5+L6)*L1	42
8	Annual Cost - 200 hours		16.90

Peak Allocation of Combustion Turbine (30 Years)

Line	Item	Calculation	Cost
9	1/2 Fixed CT Cost ($/kW Year) - Peak Credit Number 1993$		57.07

5 Year Contract Value

Line	Item	Calculation	Cost
10	5 Year Value Adjustment - 1/4 Between 1 and 30 Contract ($/yr)	(0.75*L8)+0.25*L9	27
11	Capacity Payment ($/kw-Yr)	(0.50 * L10)	13.47
12	Energy Payment (mills / kWh)	(L10 - L11)/5	67

Additional Monthly Charge Calculations

Line	Item	Calculation	Cost
13	Sched 24 / 31 Meter Upgrade		200.00
14	Meter Life		30
15	Fixed Charge Rate (30 years)		13.26%
16	Meter Annual Cost	(L13*L15)	26.52

Additional Monthly Charges If An Interruption

Line	Item	Calculation	Cost
17	Meter Reading - Schedule 49		$0.00
18	Meter Reading - Schedule 24 & 31		$11
19	Data Processing - Schedule 49		$0.00
20	Data Processing - Schedule 24 & 31		$11

Additional Charges Per Interruption

Line	Item	Calculation	Cost
21	Notification Fax		$0.50

Large Power Interruptible Rates - Alternative Proposal

Lost Revenues

Line	Item	Calculation	Cost
22	Winter Schedule 26 - Moderation Proposal ($/kWh)		0.042437
23	Winter Schedule 31 - Moderation Proposal ($/kWh)		0.035405
24	Winter Schedule 49 - Moderation Proposal ($/kWh)		0.031225

Value of Interruptible Load

Line	Interruptle Demand Type	Calculation	$/kW -Year	$/kWh
25	Short Term Firm, 1 Year Contract	L4 & L7	$8.45	0.0422
26	Long Term Firm, 5 Year Contract	L11 & L12	$13.47	0.0673
27	Non-Firm - 50% of 1 Year Contract		$0.00	0.0422
28	Short Term Firm, 1 Year Contract - Restated		8.4	0.0425
29	Long Term Firm, 5 Year Contract - Restated		15	0.0600
30	Non-Firm - 50% of 1 Year Contract - Restated			0.0425

Credits By Schedule

Line	Interruptle Demand Type	Calculation	$/kW -Year	$/kWh
31	Schedule 36 - Short Term Firm, 1 Year Contract	L28 & L28 - L22	8.4	0.0001
32	Schedule 36 - Long Term Firm, 5 Year Contract	L29 & L29 - L22	15	0.0176
33	Schedule 36 - Non-Firm - 50% of 1 Year Contract	L30 - L22	0	0.0001
34	Schedule 38 - Short Term Firm, 1 Year Contract	L28 & L28 - L23	8.4	0.0071
35	Schedule 38 - Long Term Firm, 5 Year Contract	L29 & L29 - L23	15	0.0246
36	Schedule 38 - Non-Firm - 50% of 1 Year Contract	L30 - L23	0	0.0071
37	Schedule 39 - Short Term Firm, 1 Year Contract	L28 & L28 - L24	8.4	0.0113
38	Schedule 39 - Long Term Firm, 5 Year Contract	L29 & L29 - L24	15	0.0288
39	Schedule 39 - Non-Firm - 50% of 1 Year Contract	L30 - L24	0	0.0113