PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 24, 2012

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Washington Utilities and Transportation Commission
1300 S. Evergreen Park Drive SW
P.O. Box 47250
Olympia, WA 98504-7250

Attention: David W. Danner
Executive Director and Secretary

RE: **Advice No 11-03, Docket No. UE-112226**
Schedules of Estimated Avoided Cost and Update to Schedule 37 – Avoided Cost Purchases from Cogeneration and Small Power Purchases

Dear Mr. Danner:

Pursuant to RCW 80.28.050 and 80.28.060, WAC 480-107-055 and WAC 480-107-095 and the Washington Utilities and Transportation Commission's (Commission) Rules and Regulations, PacifiCorp, d.b.a. Pacific Power & Light Company, (Company) submits for filing an original and two copies of proposed tariffs applicable to Pacific Power's electric service in the state of Washington. Based on discussions with Staff, the Company respectfully requests an effective date of April 13, 2012.

First Revision of Sheet No. 37.2	Schedule 37	Avoided Cost Purchases from Cogeneration and Small Power Production

On December 29, 2011, the Commission approved PacifiCorp's Market Request for Proposals (Market RFP) in Docket UE-111804 which resulted in the acceptance of a 50 MW, third quarter 2012 power purchase. On December 30, 2011 PacifiCorp filed updated avoided costs with the Commission requesting an effective date of February 29, 2012.

On February 13, 2012, based on discussions with Staff, the Company requested an extension of the proposed tariff effective date in order to allow the Company to update forward price curves and to complete additional analysis requested by Staff. The proposed rates in this filing reflect the update in the forward price curves, the addition of the Market RFP, and the extension of avoided costs from five years to ten years when compared to the Company's filing of December 30, 2011.

Also enclosed is the notice to customers, a summary page of tariff changes and the avoided cost calculation exhibit.

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

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

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, Oregon, 97232

Informal questions should be directed to Carla Bird at (503) 813-5269.

Sincerely,

William R. Griffith
Vice President, Regulation

Enclosures

Attachments and Exhibits
Attachment A: Notice
Attachment B: Summary Page of Tariffs
Attachment C: Proposed Tariff Schedule 37
Exhibit 1: Summary of the Company's avoided cost calculation methodology

ATTACHMENT A

Attachment A

NOTICE
PACIFIC POWER

Pursuant to Washington Law (including without limitation RCW 80.28.050 and -060) and the Washington Utilities and Transportation Commission's (the "Commission") Rules & Regulations, Pacific Power has filed with the Commission the original tariff schedules for electric service in the State of Washington.

Overview

The Company's current avoided cost prices and Schedule 37 became effective in February 2011. Since that time resource requirements, natural gas prices and market prices have changed, as have the Company's avoided costs. This filing updates the Company's estimated avoided cost prices and Schedule 37 based on the costs that the Company would expect to pay "but for" the Qualifying Facility resource.

The Commission will examine the Company's proposed tariff sheets. As a result of such examination, the Commission may determine that any or all of said schedules should be accepted as filed, modified or rejected.

DATED: February 24, 2012

PACIFIC POWER

By______________________
William R. Griffith
Vice President, Regulation
Pacific Power

ATTACHMENT B

The proposed tariff sheets to be revised in Pacific Power's currently effective Tariff WN U-75 are designated as follows:

First Revision of Sheet No. 37.2	Schedule 37	Cogeneration and Small Power Production

ATTACHMENT C

Schedule 37
COGENERATION AND SMALL POWER PRODUCTION

TERMS AND CONDITIONS: (continued)

6. The Company will purchase the entire output from the Seller's facility, or if the Seller wishes to reduce his net delivery and billing from the Company, the Company will purchase the net output from the Seller's facility. The metering configuration to measure such purchases will be specified in the Power Purchase Agreement and/or Interconnection Agreement.

7. The Avoided Cost rates are fixed for five years. However, these rates are recalculated every year and applicable to any seller that enters into power purchase agreement with PacifiCorp in that year.

GENERAL RULES AND PROVISIONS:
Service under this schedule is subject to the General Rules and Provisions contained in this tariff.

AVOIDED COST RATES:

Deliveries During Calendar Year	Capacity Payment $/kW - Month	Energy Payment $/MWH	
2012	$0.00	26.07	(C)
2013	$2.35	31.78	
2014	$2.39	34.84	
2015	$2.44	37.42	
2016	$2.49	40.21	(C)
2017	$2.54	42.92	(N)
2018	$2.58	46.89	
2019	$2.63	50.69	
2020	$2.68	49.28	
2021	$2.72	59.58	(N)

No capacity payment is made in 2012 because the Company is capacity surplus during the winter peak 2012. (C) (C)

EXHIBIT 1

PACIFIC POWER
AVOIDED COST CALCULATION

WASHINGTON – FEBRUARY 2012

PACIFIC POWER
AVOIDED COST CALCULATION

WASHINGTON - FEBRUARY 2012

The starting point for the avoided cost calculation is the load and resource balance developed for the Company's 2011 Integrated Resource Plan (IRP). It should be noted that many of the input assumptions for the IRP were fixed in December 2010, in order to enable filing of the IRP in March 2011. Due to the age of the input assumptions, some of the inputs have been updated for known changes for purposes of this avoided cost calculation. The avoided cost prices were also developed consistent with the west control area allocation methodology adopted for the Company in Docket No. UE-061546, Order 08.

Loads and Resources

The Company's November 2011 load forecast was used in the study.

Long-term sales and purchase contracts were updated to include information available as of mid-December 2011. These changes include the addition or revision of several long-term purchase contracts[1].

Table 1 presents the Company's west control area loads and resource balance. Table 1 shows an energy balance with a surplus of 507 aMW in 2012 declining to a surplus of 38 aMW in 2021. The winter peak has a capacity surplus of 43 MW in 2012 and a capacity deficit of over 400 MW in 2013 through 2021. The summer months have a capacity deficit in all years.

Avoided Cost Calculation

Based on the load and resource energy balance, the avoided cost calculation is separated into two distinct periods: (1) the Short Run – a period of resource sufficiency in which the avoided costs are based on the marginal production cost of existing resources plus the cost of purchasing winter capacity in the years when the winter season is capacity deficient; and (2) the Long Run – a resource deficit period in which new resources are required to provide both capacity and energy to meet the Company's resource requirements. Avoided costs during the deficit period are based on the cost of a combined cycle combustion turbine. The load and resource energy balances in the Company's west control area in Table 1 indicates resource sufficiency for all ten years, therefore, only Short Run avoided costs are included in the current filing.

[1] Additions and revisions to the long-term contracts portfolio include the termination of the Grant County 10 aMW purchase,and extension of the Seattle City Light Stateline contract .

Short Run Avoided Costs

The annual summary of load and resource balance is shown in **Table 1**, which indicates that the Company's west control area is resource sufficient in all five years. During periods of resource sufficiency, avoided energy costs are based on the displacement of purchased power and existing thermal resources calculated by the Company's production cost model, GRID. To calculate short-run avoided costs, two production cost studies are prepared using GRID. The only difference between the two studies is an assumed 50 aMW and zero cost resource. The 50 aMW resource is a proxy for qualifying facility generation. The avoided energy cost is the difference between the two studies. The outputs of the production cost model run are provided as **Table 2**.

Winter capacity costs in 2013 through 2021 are based on three-month capacity purchases. The annual value as shown in **Table 3** is one-fourth of the total fixed costs of a west side simple cycle combustion turbine (SCCT) as listed in the Company's 2011 IRP. Because energy generated by a qualifying facility may vary, avoided costs at 75%, 85% and 95% capacity factors are prepared to illustrate the impact of differing generation levels. This calculation is also shown in Table 3.

Avoided energy costs can be differentiated between on-peak and off-peak periods. To make this calculation, the Company assumed that all capacity costs are incurred to meet on-peak load requirements. On an annual basis, approximately 57% of all hours are on-peak and 43% are off-peak. **Table 4** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Table 5** shows a comparison between the avoided costs currently in effect in Washington and the proposed avoided costs in this filing.

Table 6 shows the calculation of the total fixed costs of a SCCT that are used in Table 3.

Table 1
Loads and Resources
2012 through 2021

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
aMW										
Net Load	2,245	2,264	2,285	2,290	2,294	2,315	2,320	2,326	2,328	2,329
Long Term Sales	334	259	259	219	219	219	219	219	219	219
Short Term Firm Sales	5	-	-	-	-	-	-	-	-	-
Total Requirements	2,584	2,523	2,543	2,509	2,513	2,533	2,539	2,545	2,547	2,548
Long Term Purchases	272	255	255	255	244	244	244	239	239	239
Short Term Firm Purchase	379	42	5	3	-	-	-	-	-	-
Thermal Generation	1,922	1,922	1,923	1,923	1,923	1,923	1,923	1,923	1,923	1,923
Other Generation	562	566	569	571	571	573	563	543	538	460
Reserves	(44)	(45)	(43)	(43)	(42)	(41)	(38)	(39)	(37)	(35)
Total Resources after Reserves	3,091	2,740	2,709	2,709	2,696	2,699	2,691	2,665	2,663	2,586
Surplus / (Deficit)	507	216	166	200	183	166	152	121	116	38
Percent Surplus / (Deficit)	19.6%	8.6%	6.5%	8.0%	7.3%	6.5%	6.0%	4.7%	4.6%	1.5%
Peak (July)										
Net Load	3,329	3,356	3,389	3,403	3,416	3,451	3,468	3,476	3,483	3,492
Long Term Sales	794	794	794	694	694	694	694	694	694	694
Short Term Firm Sales	-	-	-	-	-	-	-	-	-	-
Total Requirements	4,122	4,150	4,183	4,096	4,110	4,145	4,162	4,170	4,177	4,185
Long Term Purchases	537	470	336	336	302	302	302	253	253	253
Short Term Firm Purchase	-	100	-	-	-	-	-	-	-	-
Thermal Generation	1,915	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917	1,917
Other Generation	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	1,043	874
Reserves	(182)	(182)	(183)	(183)	(182)	(182)	(182)	(179)	(180)	(176)
Total Resources after Reserves	3,312	3,348	3,112	3,112	3,079	3,079	3,079	3,033	3,033	2,867
Surplus / (Deficit)	(810)	(802)	(1,071)	(984)	(1,031)	(1,065)	(1,083)	(1,136)	(1,144)	(1,318)
Percent Surplus / (Deficit)	-19.6%	-19.3%	-25.6%	-24.0%	-25.1%	-25.7%	-26.0%	-27.3%	-27.4%	-31.5%
Peak (January)										
Net Load	3,580	3,619	3,648	3,672	3,679	3,702	3,729	3,737	3,747	3,754
Long Term Sales	285	185	185	85	85	85	85	85	85	85
Short Term Firm Sales	-	-	-	-	-	-	-	-	-	-
Total Requirements	3,866	3,805	3,833	3,757	3,764	3,787	3,814	3,822	3,832	3,840
Long Term Purchases	387	358	358	358	324	324	324	280	280	280
Short Term Firm Purchase	525	-	-	-	-	-	-	-	-	-
Thermal Generation	2,075	2,075	2,077	2,077	2,077	2,077	2,077	2,077	2,077	2,077
Other Generation	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	1,125	947
Reserves	(203)	(199)	(200)	(199)	(201)	(203)	(203)	(200)	(200)	(193)
Total Resources after Reserves	3,909	3,359	3,360	3,361	3,325	3,323	3,323	3,281	3,282	3,111
Surplus / (Deficit)	43	(446)	(474)	(396)	(439)	(464)	(491)	(541)	(551)	(729)
Percent Surplus / (Deficit)	1.1%	-11.7%	-12.4%	-10.5%	-11.7%	-12.3%	-12.9%	-14.1%	-14.4%	-19.0%

Table 2
Avoided Costs ($/MWh)
Non-Firm Energy

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
GRID Production Cost Study												
2012	26.67	25.38	24.38	22.52	17.72	13.09	25.79	31.31	30.26	29.79	31.73	33.89
2013	33.81	32.19	28.77	26.91	20.24	17.93	30.58	38.05	37.99	35.94	38.26	40.53
2014	37.53	35.91	32.57	27.43	21.03	18.73	34.22	41.42	41.84	40.12	42.32	44.74
2015	40.11	38.49	34.99	30.01	23.28	21.60	36.81	44.00	44.41	42.73	44.99	47.39
2016	42.68	41.29	37.98	33.01	25.98	24.41	39.17	47.20	47.20	45.35	47.92	50.15
2017	45.32	43.98	40.73	35.42	29.14	27.18	41.88	49.98	49.95	48.11	50.61	52.56
2018	48.10	45.94	42.14	41.02	37.87	38.14	50.00	54.21	52.23	49.07	50.65	53.03
2019	48.78	47.76	43.42	46.77	46.68	48.82	58.52	58.38	54.88	49.87	50.67	53.44
2020	49.58	44.66	41.37	43.55	43.61	45.66	57.18	56.49	54.58	49.22	50.97	53.93
2021	56.99	55.70	53.30	52.82	54.20	54.79	65.69	66.98	63.40	61.31	63.43	65.86

Annual Seasonal Average

	Winter Season	Summer Season	Annual Wtd Average
2012	$26.51	$25.11	$26.07
2013	$32.08	$31.14	$31.78
2014	$35.21	$34.05	$34.84
2015	$37.75	$36.70	$37.42
2016	$40.54	$39.50	$40.21
2017	$43.23	$42.25	$42.92
2018	$45.98	$48.65	$46.89
2019	$48.42	$55.15	$50.69
2020	$47.11	$53.48	$49.28
2021	$57.95	$62.72	$59.58

Source: GRID Production Cost Study
Annual Wtd Average: Weighted by the number of days in a month

Table 3
Total Avoided Cost

Year	Avoided Firm Capacity Costs	Total Avoided Energy Cost	Total Avoided Costs At Stated Capacity Factor		
			75%	85%	90%
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
			(b)+((a)/8.76 x 0.75)	(b)+((a)/8.76 x 0.85)	(b)+((a)/8.76 x 0.9)
Avoided Resource					
2012	(1)	$26.07	$26.07	$26.07	$26.07
2013	$28.20	$31.78	$36.07	$35.57	$35.36
2014	$28.73	$34.84	$39.21	$38.70	$38.48
2015	$29.31	$37.42	$41.88	$41.36	$41.14
2016	$29.86	$40.21	$44.76	$44.22	$44.00
2017	$30.43	$42.92	$47.55	$47.01	$46.78
2018	$31.01	$46.89	$51.61	$51.05	$50.82
2019	$31.57	$50.69	$55.50	$54.93	$54.69
2020	$32.11	$49.28	$54.17	$53.59	$53.35
2021	$32.68	$59.58	$64.55	$63.97	$63.73

Columns
- (a) Table 6 Column (f) for three months (multiplied by 3/12)
- (b) Table 2 Annual Average

Note: (1) No capacity payment is made in 2012 because the Company is capacity surplus during the winter peak 2012.

Table 4
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Avoided Energy Cost	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 57%)		(b) + (c)	(c)
Avoided Resource					
2012	(1)		$26.07	$26.07	$26.07
2013	$28.20	$5.65	$31.78	$37.43	$31.78
2014	$28.73	$5.75	$34.84	$40.59	$34.84
2015	$29.31	$5.87	$37.42	$43.29	$37.42
2016	$29.86	$5.98	$40.21	$46.19	$40.21
2017	$30.43	$6.09	$42.92	$49.01	$42.92
2018	$31.01	$6.21	$46.89	$53.10	$46.89
2019	$31.57	$6.32	$50.69	$57.01	$50.69
2020	$32.11	$6.43	$49.28	$55.71	$49.28
2021	$32.68	$6.55	$59.58	$66.13	$59.58

Columns
- (a) Table 3 Column (a)
- (b) 8760 is the number of hours in the year, 57% is the percent of On-Peak Hours
- (c) Table 3 Column (b)

Note: (1) No capacity payment is made in 2012 because the Company is capacity surplus during the winter peak 2012.

Table 5
Comparison between Proposed and Current Avoided Costs

Year	Total Avoided Costs at 85% CF		
	Proposed Avoided Costs ($/MWh)	Washington Approved Avoided Costs ($/MWh)	Difference ($/MWh)
	(a)	(b)	(c) (a) - (b)
2011		$31.36	
2012	$26.07	$39.62	-$13.55
2013	$35.57	$41.75	-$6.18
2014	$38.70	$43.65	-$4.95
2015	$41.36	$45.74	-$4.38
2016	$44.22		$44.22
2017	$47.01		
2018	$51.05		
2019	$54.93		
2020	$53.59		
2021	$63.97		

Levelized Prices $/MWH (Nominal) @ 7.17% Discount Rate (1)		
5 Year (2011 - 2015)		39.96
5 Year (2012 - 2021)	43.64	

Columns
(a) Table 3 Column (d)
(b) Avoided Costs Approved by the Commission February 10, 2011

Note: (1) Discount Rate - 2011 IRP

Table 6
Total Cost of Displaceable Resources
SCCT Frame (2 Frame "F") - West Side Options (1500')

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Variable O&M	Total O&M at Expected CF	Total Resource Fixed Costs
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/kW-yr	$/kW-yr
	(a)	(b)	(c)	(d)	(e)	(f)
2010	$901	$75.77	$5.42	$13.87	$30.94	$106.71
2011		$77.51	$5.54	$14.19	$31.64	$109.15
2012		$78.67	$5.62	$14.40	$32.11	$110.78
2013		$80.09	$5.72	$14.66	$32.69	$112.78
2014		$81.61	$5.83	$14.94	$33.31	$114.92
2015		$83.24	$5.95	$15.24	$33.99	$117.23
2016		$84.82	$6.06	$15.53	$34.63	$119.45
2017		$86.43	$6.18	$15.83	$35.30	$121.73
2018		$88.07	$6.30	$16.13	$35.97	$124.04
2019		$89.66	$6.41	$16.42	$36.62	$126.28
2020		$91.18	$6.52	$16.70	$37.24	$128.42
2021		$92.82	$6.64	$17.00	$37.91	$130.73

Source: (a)(c)(d) Plant Costs - 2011 IRP - Table 6.4
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x 21%) + (c)
(f) = (b) + (e)

SCCT Frame (2 Frame "F") - West Side Options (1500')			
	405	Plant capacity	MW
$	901	Plant capacity cost	$/kW
$	5.42	Fixed O&M plus on-going capital cost	$/kW-yr
$	13.87	Variable O&M and Other Costs	$/MWH
$	6.51	Variable O&M	$/MWH
$	7.36	Fixed Pipeline Costs Included Above	$/MWH
	8.41%	Payment Factor	
	21%	Capacity Factor	

Company Official Inflation Forecast - Dated December 2011					
2011	2.30%	2015	2.00%	2019	1.80%
2012	1.50%	2016	1.90%	2020	1.70%
2013	1.80%	2017	1.90%	2021	1.80%
2014	1.90%	2018	1.90%		