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SERVICE DATE

JAN 15 1992

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

In the Matter of the Petition of PacifiCorp, d/b/a Pacific Power & Light Company, for Approvals Regarding (1) Valuations and (2) Accounting in Connection with a Proposed Acquisition of Generating Resources from Colorado-Ute Electric Association, Inc.	Docket No. UE-911186(P) ORDER GRANTING PETITION AS AMENDED

On October 15, 1991, PacifiCorp d/b/a Pacific Power & Light Company (PacifiCorp or Company) filed a Petition for approvals regarding valuations and accounting in connection with its proposed acquisition of generating resources from Colorado-Ute Electric Association, Inc. (Colorado-Ute). On December 27, 1991, the Company filed an amendment to its Petition, removing its request for approval of valuations of the acquired resources. The Company does request a Commission order allowing the costs of the proposed acquisition to be recorded on the Company's books of account in the manner described in the Amended Petition.

The proposed acquisitions are part of a Joint Plan of Reorganization (Joint Plan) filed in the Colorado-Ute reorganization proceeding by PacifiCorp, Public Service Company of Colorado (PSCo) and Tri-State Generation and Transmission Association (Tri-State).

According to the Amended Petition, the Joint Plan was filed with the United States Bankruptcy Court for the District of Colorado on September 26, 1991. PacifiCorp anticipates that the Joint Plan will be confirmed by the Bankruptcy Court in January 1992. Under the terms of the Joint Plan, PacifiCorp will acquire

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 231
ADMIT ☑ W/D ☐ REJECT ☐

an 82.5 MW interest in each of Craig Units 1 and 2, a 45 MW share of Hayden Unit 1, a 33 MW share of Hayden Unit 2 (for a total of 243 MW) and two-thirds of Colorado-Ute's interest in the Trapper Coal Mine. Craig Units 1 and 2 are coal-fired generating stations located near Craig, Colorado. Hayden Units 1 and 2 are coal-fired generating stations located near Hayden, Colorado. The Trapper Coal Mine is the primary coal supply for Craig Units 1 and 2.

PacifiCorp states it expects the total purchase price for these assets to be approximately $260 million, which exceeds the depreciated book cost of these assets by an estimated $135 million. PacifiCorp seeks Commission permission to record this $135 million on its books of accounts as an acquisition adjustment.

According to the Amended Petition, the Joint Plan also includes provisions for power sale, transmission and capacity exchange agreements between PacifiCorp and the other parties to the Joint Plan. Under these provisions, PacifiCorp and PSCo will enter into an agreement for a 176 MW system power sale; PSCo and Tri-State will agree to provide PacifiCorp 67 MW of on-peak and 100 MW of off-peak transmission from Craig, Colorado to the Four Corners area; and PacifiCorp and Tri-State will enter into a 50 MW winter/summer seasonal capacity exchange agreement.

While the Company states that the proposed acquisition represents a unique opportunity to obtain resources for its customers during a limited "window of opportunity," at a cost that is less than the cost of alternative resources, the Company in this docket is not seeking a Commission decision concerning the

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ratemaking treatment of the acquired assets. In this docket, the Commission makes no determinations regarding the merits of the proposed transaction.

In past rate proceedings, the Commission has recognized that under appropriate circumstances, acquisition adjustments may be allowed for ratemaking purposes, if in the public interest. See e.g., Washington Pub. Serv. Comm'n v. Northwest Nat. Gas Co., Cause No. U-9117, 32 PUR3d 355 (Feb. 11, 1960); Washington Pub. Serv. Comm'n v. Pacific Power & Light Co., Cause No. U-9097, 33 PUR3d 433 (March 23, 1960); Washington Util. & Transp. Comm'n v. Continental Tel. Co., Cause No. U-75-46, 14 PUR4th 276 (April 2, 1976).

The appropriate amount of the purchase price to be included in PacifiCorp's ratebase should be determined in a rate proceeding, or other appropriate proceeding.

WHEREFORE, IT IS HEREBY ORDERED That:

1. PacifiCorp is authorized to record the acquisition costs of the Colorado-Ute generating resources on its books of accounts in the manner described in the Company's Amended Petition.

2. The allowance of acquisition adjustments for ratemaking purposes is a matter addressed to the Commission's discretion, based upon the Commission's duty to regulate in the public interest, considering all relevant facts and circumstances. By entering its Order in this docket, the Commission has made no determination regarding the merits of the proposed acquisition or the amount of PacifiCorp's investment that may be included in

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ratebase in a future proceeding. Such determinations are reserved for a rate proceeding, or other appropriate proceeding.

DATED at Olympia, Washington this 15th day of January, 1992.

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Sharon L. Nelson

SHARON L. NELSON, Chairman

A.J. Pardini

A.J. PARDINI, Commissioner

UE-991262/PacifiCorp
September 27, 1999
Public Counsel Data Request 23

Public Counsel Data Request No. 23:

Referring to exhibit RW-2, the line noted as "Heat Rate Improvements", provide the annual heat rates, and annual rate of improvement, for each thermal generating plant over 100 mw owned by the Company for each year since commercial operation.

Response to Public Counsel Data Request No 23:

The requested information that is readily available is provided as Attachment Response PC 23.

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Attachment PC 23

HEAT RATE COMPARISON

Actual Annual Average Net Plant Heat Rates based on HHV (Gross Calorific Value) in BTU/KWh as reported in FERC Form No. 1

	1990	1991	1992	1993	1994	1995	1996	1997	1998
PacifiCorp Owned and Operated Plants									
Coal Fired Plants:									
Carbon	11094	10863	10653	11381	11030	11304	11282	11253	11314
Centralia	10484	10527	10528	10419	10364	10638	10650	10469	10419
Dave Johnston	10948	11071	11239	10939	11040	11052	10946	11393	11270
Hunter	10381	10212	10329	10456	10404	10598	10376	11051	10699
Huntington	10233	10019	10154	10334	9950	10141	10465	9967	10159
Jim Bridger	10261	10074	10266	10347	10457	10601	10606	10499	10529
Naughton	10380	10384	10479	10690	10515	10502	10260	10740	10412
Wyodak	11865	11910	11785	11820	11883	11898	11933	12006	11968
Natural Gas Fired Plants:									
Gadsby	n.a.	11815	11560	11611	12154	11801	13023	12552	11310
PacifiCorp Owned - Operated by Others									
Coal Fired Plants:									
Cholla	n.a.	10741	10286	10617	10623	10912	10847	10711	10722
Craig	n.a.	n.a.	10180	9936	10159	10203	10002	10269	10025
Colstrip	10751	10425	10714	10838	10605	10861	10731	10806	10666
Hayden	n.a.	n.a.	n.a.	10357	10327	10347	10418	10466	10540
Natural Gas Fired Plants:									
Hermiston	n.a.	n.a.	n.a.	n.a.	n.a.	n.a.	7078	7215	7181

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UE-991262/PacifiCorp
November 30, 1999
Public Counsel Data Request No. 49

Public Counsel Data Request No. 49:

Provide any estimate the Company has prepared of the value of power from Centralia relative to market price index power at Mid-Columbia and/or California/Oregon Border, taking into account any of the following:

a) the proximity of Centralia to loads
b) ancillary service value of Centralia
c) transmission cost and losses
d) economic dispatch of Centralia during low-price periods

Response to Public Counsel Data Request No 49:

The Company has not prepared any economic studies responsive to the request other than those included in the Company's filing.

WUTC DOCKET NO. UE-991255
EXHIBIT NO. 233
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UE-991262/PacifiCorp
November 4, 1999
Public Counsel Data Request 33

Public Counsel Data Request No. 33:

Provide all avoided cost estimates prepared by the Company and filed with any regulatory commission for any purpose since January 1, 1996.

Response to Public Counsel Data Request No 33:

The requested information is provided as Attachment Response PC 33.

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825 N.E. Multnomah
Portland, Oregon 97232
(503) 464-5000

PACIFICORP
PACIFIC POWER UTAH POWER

June 4, 1999

Ms. Janice Fulker, Administrator
Regulatory and Technical Support
Public Utility Commission of Oregon
550 Capital Street, N.E.
Salem, Oregon 97310-1380

SUBJECT: **Advice No. 99-004**
Schedule 5 – Partial Requirements Service - Revised

Dear Ms. Fulker:

Pacific Power & Light Company recently received acknowledgment of its RAMPP-5 report from the Commission and with this filing is complying with the Commission requirement that the Company files for approval of its avoided costs within 30 days of the acknowledgement. These avoided costs vary from those approved by the Commission during 1996 primarily because of an increase in the expected escalation of gas prices and the Company's first deficit year has been revised from 2010 to 2000. The Company's first deficit year changes are related to the sale of the Company's 636 MW share of the Centralia generation project.

In addition, the Company requests that the Commission establish a five-year term for contracts for firm power deliveries from QF contracts as it has done for Portland General Electric. In Order No. 91-1383, the Commission states that "...the further into the future projections are made, the greater the risk that the projections will not accurately represent actual conditions at the end of the projection period." Currently, the majority of long-term power purchase contracts are negotiated for three to five years. The Company believes that longer-term contracts pose significant risks to the Company and its customers because there are significantly different values and the information is not considered reliable. For these reasons we believe it would create undue financial exposure to contract with a QF outside the Company's current five-year planning horizon.

OAR860-29-040 (5)

Standard rates for purchases from qualifying facilities with a generating design capacity of 1000 kW or less are set forth in revised Schedule 5. Pacific hereby submits an original and four copies bearing an effective date of July 21, 1999. Workpapers used to develop the revised Schedule 5 prices are provided as Attachment A, Exhibit 1.

OAR 860-29-080 (3)a

Peak and Off-Peak Energy: The prices for purchases of peak and off-peak energy, expressed in cents per kWh on a seasonally differentiated basis, are set forth in Attachment A, Exhibit 1.

OAR 860-29-080 (3) b

Pacific plans to meet future energy requirements with a balanced mix of new sources on the supply side and demand side. The appropriate timing and mix of new sources has been analyzed in Pacific's resource planning process, and is described in the report documenting that process, PacifiCorp's Resource and Market Planning Program (RAMPP-5). The timing has been revised to reflect the sale of the Company's Montana and California Distribution properties and the Centralia generation project.

For the purpose of defining long-term avoided costs, gas-fired combustion turbines have been identified as the avoidable resources. For the period 2000 and beyond, the complete cost of a combined cycle combustion turbine is identified as the avoided cost. An overview of the assumptions used to develop the Company's avoided costs is provided as Attachment B.

In addition, the Company proposes an option whereby the portion of energy costs related to the fuel cost of a combined cycle combustion turbine will be based on a published index indicative of gas prices in the Pacific Northwest. The index selected will be determined at the time of negotiations. This option will only be available if mutually agreed to by both parties.

OAR 860-29-080 (3) c

Pacific's proposed prices for purchase from qualifying facilities with a design capacity of 1000 kilowatts or less are set forth in Schedule 5. Prices for facilities over 1000 kilowatts will be determined through negotiations on a case by case basis.

Pacific intends to have this filing supercede all previously filed avoided costs, and Pacific will use these avoided costs beginning July 21, 1999.

If you have questions regarding this filing, please contact Mark Widmer at 813-5541 or me at 813-5546.

Sincerely,

Rodger Weaver

Rodger Weaver
Director, Regulatory and Strategy Support

Available:
In all territory served by Company in Oregon.

Applicable:
To qualifying facilities with a generating design capacity of 1000 kW or less.

Monthly Billing:
The monthly billing to the qualifying facility shall be the sum of the Basic Charge specified hereunder and the monthly billing for takings from Company, in accordance with the applicable schedule or schedules for the type of service received.

Basic Charge:
$5.00 per month

Generation Credit (On-Peak):
Company, in accordance with the terms of a contract between the qualifying facility and Company, shall pay, for all separately metered kilowatt-hours of qualifying facility on-peak generation, 2.71 cents per kilowatt-hour for the period November through April, and 2.52 cents per kilowatt-hour for the period May through October. Peak hours are defined as 6:00 a.m. to 10:00 p.m., Monday through Saturday.

Generation Credit (Off-Peak):
Company, in accordance with the terms of a contract between the qualifying facility and Company, shall pay, for all separately metered kilowatt-hours of qualifying facility off-peak generation, 1.74 cents per kilowatt-hour for the period November through April, and 1.55 cents per kilowatt-hour for the period May through October. Off-peak hours are defined as 10:00 p.m. to 6:00 a.m., Monday through Saturday and all day Sunday.

Parallel Operation:
Interconnection of a qualifying facility with Company's system will be permitted only under the terms of a contract between the qualifying facility and Company. Such contract shall include but not be limited to the following:

(1) The qualifying facility shall indemnify and hold harmless the Company from any and all liability arising from the operation and interconnection of qualifying facility.

(2) Qualifying facility shall provide a lockable disconnect switch to isolate qualifying facility's generation from Company's system. Such switch shall be accessible to Company and Company shall have the right to lock such disconnect switch open whenever necessary to maintain safe electrical operating conditions, or whenever the qualifying facility adversely affects Company's system.

(3) Qualifying facility shall provide an additional meter base adjacent to the delivery meter to measure the qualifying facility's total generation independently from the qualifying facility's load. For three-phase generation the qualifying facility will also provide a meter base for a kvar meter.

(4) Except for the metering, qualifying facility shall own and maintain all facilities on the qualifying facility's side of a single point of delivery as specified by Company. Qualifying facility's system, including interconnecting equipment, shall meet the requirements of and be inspected and approved by state electrical inspector and any other public authority having jurisdiction before any connection is made to Company.

Unmetered Generation:
If the qualifying facility does not desire to make sales to Company, then the requirement for separate metering of the generation shall be waived. Such generation may reduce the net delivery and billing to the qualifying facility by Company. The delivery meter will be of a type that will not reverse registration and the qualifying facility will not be compensated for unmetered incidental flows to Company.

(continued)

Qualifying Facilities with Generating Capacity Greater than 1000 kW:

Prices for purchase of capacity and energy from qualifying facilities with generating capacity in excess of 1000 kW will be established on the basis of negotiation between the qualifying facility and the Company on a case-by-case basis. These negotiations will be conducted consistent with the Commission's rules concerning qualifying facilities, Oregon Administrative Rules Chapter 860, Division 29. The following factors will, to the extent practicable, be taken into account [See OAR 860-29-040(6)]:

(a) The data filed with the Commission and available to qualifying facilities pursuant to OAR 860-29-080(3), including the avoided energy and capacity cost information presented in Appendices A, B, C, and D;

(b) The availability of capacity and energy from a qualifying facility during the system daily and seasonal peak periods, including:

(A) The ability of the Company to dispatch output of the qualifying facility;
(B) The expected or demonstrated reliability of the qualifying facility;
(C) The terms of any contract or other legally enforceable obligation;
(D) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with the scheduled outages of the Company's facilities;
(E) The usefulness of energy and/or capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
(F) The individual and aggregate value of energy and capacity from qualifying facilities on the Company's system; and
(G) The smaller capacity increments and the shorter lead times available, if any, with additions of capacity from qualifying facilities.

(c) The relationship of the availability of energy and/or capacity from the qualifying facility as derived in subsection (b), to the ability of the Company to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use;

(d) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility if the Company generated an equivalent amount of energy and/or capacity; and

(e) Relevant factors regarding the supply characteristics of the different technologies.

PacifiCorp

Attachment A

June 4, 1999

EXHIBIT 1

PACIFICORP

1999 RAMPP-5 Non-Levelized Avoided Cost Estimates
Rates in cents per kwh

Year No.	Year	0.0908 PW Factor	CAPACITY (85%) ($/kw-mo)	CAPACITY (85%) (cents/kwh)	VARIABLE ENERGY * On-Peak (cents/kwh)	VARIABLE ENERGY * Off-Peak (cents/kwh)	TOTAL FIRM ** On-Peak (cents/kwh)	TOTAL FIRM ** Off-Peak (cents/kwh)	ANNUAL AVERAGE (cents/kwh)
1	1999	0.917	0.00	0.00	2.04	1.07	2.04	1.07	1.63
2	2000	0.840	4.05	0.65	2.06	1.09	2.71	1.74	2.29
3	2001	0.770	4.18	0.67	2.12	1.15	2.80	1.83	2.38
4	2002	0.706	4.30	0.69	2.19	1.22	2.88	1.91	2.47
5	2003	0.648	4.43	0.71	2.29	1.32	3.01	2.03	2.59
6	2004	0.594	4.56	0.73	2.37	1.40	3.10	2.13	2.68
7	2005	0.544	4.70	0.76	2.44	1.47	3.20	2.23	2.78
8	2006	0.499	4.84	0.78	2.53	1.56	3.31	2.34	2.89
9	2007	0.457	4.99	0.80	2.61	1.64	3.41	2.44	3.00
10	2008	0.419	5.13	0.83	2.79	1.82	3.62	2.65	3.20
11	2009	0.384	5.29	0.85	2.87	1.90	3.72	2.75	3.31
12	2010	0.352	5.45	0.88	2.96	1.98	3.83	2.86	3.42
13	2011	0.323	5.61	0.90	3.04	2.07	3.95	2.97	3.53
14	2012	0.296	5.78	0.93	3.13	2.16	4.07	3.09	3.65
15	2013	0.272	5.95	0.96	3.22	2.25	4.18	3.21	3.76
16	2014	0.249	6.13	0.99	3.32	2.35	4.31	3.34	3.89
17	2015	0.228	6.32	1.02	3.42	2.45	4.44	3.47	4.02
18	2016	0.209	6.50	1.05	3.52	2.55	4.57	3.60	4.15
19	2017	0.192	6.70	1.08	3.63	2.66	4.71	3.74	4.29
20	2018	0.176	6.90	1.11	3.75	2.77	4.86	3.89	4.44

* 1999 variable energy rates on a cents per kwh basis are 1.95 on-peak and .98 off-peak for summer and 2.14 on-peak and 1.17 off-peak for winter. Beyond 1999 winter and summer rates reflect the CCCT average energy cost.

** Peak hours are 6 Am to 10 PM, Monday through Saturday. Of the 8760 hours in a year, 57% are on-peak & 43% are off-peak.

	1999 Capacity			
Year	DE-ESC. @ 5.90%	P.W. @ 3.00%	Capacity $/kW-mo	Total P.W.
1999	0.94	0.97	4.50	4.13
2000	0.89	0.94	4.50	3.78
2001	0.84	0.92	4.50	3.47
2002	0.80	0.89	4.50	3.18
2003	0.75	0.86	4.50	2.92
2004	0.71	0.84	4.50	2.67
2005	0.67	0.81	4.50	2.45
2006	0.63	0.79	4.50	2.25
2007	0.60	0.77	4.50	2.06
2008	0.56	0.74	4.50	1.89
2009	0.53	0.72	4.50	1.73
2010	0.50	0.70	4.50	1.59
2011	0.47	0.68	4.50	1.45
2012	0.45	0.66	4.50	1.33
2013	0.42	0.64	4.50	1.22
2014	0.40	0.62	4.50	1.12
2015	0.38	0.61	4.50	1.03
2016	0.36	0.59	4.50	0.94
2017	0.34	0.57	4.50	0.86
2018	0.32	0.55	4.50	0.79
			Total P.W.	$40.87

Total Present Worth:	$40.87	
Real Levelized 1999 Capacity in $/kW-mo:	$3.53	
Average ¢/kWh:	0.57	
Winter Season (¢/kWh):	0.57	
Summer Season (¢/kWh):	0.57	
Capacity Factor	0.85	
Total Winter Payments (Peak ¢/kWh):	2.71	(2.14+0.57)
Total Summer Payments (Peak ¢/kWh):	2.52	(1.95+0.57)
Total Winter Payments (Off-Peak ¢/kWh):	1.74	(1.17+.57)
Total Summer Payments (Off-Peak ¢/kWh):	1.55	(.98+.57)

PacifiCorp

Attachment B

June 4, 1999

UPDATED RAMPP-5 AVOIDED COST CALCULATIONS

The avoided cost calculation is based on a load and resource plan developed in conjunction with the Company's fifth Resource and Market Planning Program (RAMPP-5) report. For calculation of avoided costs, the base load growth scenario excluding the competition load loss adjustment is used. The resultant load and resource plan as described below is used to identify periods of resource sufficiency (i.e., no additional deferrable resources are needed to meet forecasted capacity and energy needs) and to identify the potentially "avoided" resources when new deferrable resources are required.

LOADS & RESOURCES

The load and resource plan used in the calculation of avoided cost is shown in Attachment 1, pages 1-3. The first page is the balance of energy requirements and resources. The second and third pages show the balance of capacity requirements and resources for the winter and summer peaks, respectively. The exhibit shows that PacifiCorp does not require any new deferrable resources to satisfy energy load and capacity until 2000. A combined cycle combustion turbine was selected as the measure of avoided cost beginning in 2000 when additional resources are needed to meet total energy and capacity needs.

The resources which are assumed to be added to the PacifiCorp system through 1999 are identified in Attachment 1. Several of these resources are committed resources, which for a variety of reasons are not considered by the Company to be deferrable. Among the committed resources are: 1) Demand-side resources which represent the Company's commitment to the development of programmatic conservation and 2) Upgrades to existing thermal, hydro, transmission and distribution systems which are part of the Company's long range maintenance and life extension programs. The wind generation project, which was placed in service during the last quarter of 1998, is a pilot project which, in addition to providing capacity and energy, will allow the Company to build capability and gain experience with new technologies. Of the Company's potential new resources, the combined cycle combustion turbine (CCCT) was selected for the calculation of avoided cost because it provides competitively priced capacity and energy, is deferrable and its cost is easily defined. For additional resources acquired beyond 2000, it can be assumed that the CCCT cost is representative of the cost of those resources.

Market Supplied Resources

The Company's ongoing participation in the informal, non-solicitation-based market and the Company's participation in the wholesale market provide the experience and knowledge necessary to obtain cost effective market purchased resources. As a result of the cost effectiveness of market purchased resources, the Company relies on the market for its shorter term energy and capacity requirements and may find the market to be the preferred option for meeting its longer term capacity and energy needs also.

AVOIDED COST CALCULATION

The avoided cost calculations can be broken into two distinct periods based on the Loads and Resource Plan: 1) Short Run: A period of energy sufficiency (1999) in which the avoided costs are based on the marginal production cost of existing resources plus the cost of purchasing summer capacity; 2) Long Run: A period (2000 and beyond) in which new resources are required to provide both summer and winter capacity and energy to meet the Company's loads. Avoided costs during the second period are based on the cost of a combined cycle combustion turbine, which the Company considers to be a reasonable proxy for the cost of future resources wether they are market purchaes or the acquisition of new supply side resources.

Short Run Avoided Costs

During periods of resource sufficiency, the Company's avoided energy costs are based in the displacement of purchased power and existing thermal resources as modeled by the Company's PD/Mac model. The model input data includes the monthly load and resource data which are the basis for the annual summary of loads and resources shown in Attachment 1. To calculate short-term avoided energy costs, two production cost model studies are performed. The only difference between the two studies is an assumed zero running cost 50 average megawatt increase in monthly system resources. The 50 average megawatt resource serves as a proxy for qualifying facility generation. The resulting differences in system production costs between the two studies represents PacifiCorp's avoided energy costs. The avoided energy cost could be thought of as the highest variable cost incurred to serve total system load from existing and non-deferrable resources.

The outputs of the production cost model run are provided as Attachment 2.

Long Run Avoided Costs

Beginning in 2000, the avoided costs are determined to be the fixed and variable costs of the planned resource which could be avoided or deferred; in this case a combined cycle combustion turbine is used as a proxy of future resource costs. Since combined cycle combustion turbines are built as base load units which provide both capacity and energy, it is appropriate to split the fixed cost of that unit into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT), usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity. Fixed costs associated with the construction of a CCCT which is in excess of SCCT costs is assigned to energy and is added to the variable production (fuel) cost of the CCCT to determine the total avoided energy cost.

The fuel cost of the combined cycle combustion turbine defines the avoided variable energy cost beginning in 2000. The gas price forecast used in the calculation of avoided costs is based on the gas cost analysis of RAMPP-5 which is shown in Chapter 4, Table 4-15.

The gas prices used in calculating avoided costs begin with a 1999 value of $1.69/MMBtu for a westside resource. This is composed of two parts: (1) commodity; and (2) transportation. The commodity component is $1.52/MMBtu, including shrinkage. The transportation cost is $.18/MMBtu and was based on Pacific Northwest transportation rates.

The gas price forecast is shown in Attachment 3.

Results

Attachment 4, shows the calculation of the avoided costs. Page 1 presents avoided capacity and energy costs and total costs combined at load factors of 75%, 85% and 95%. Page 2 shows the financial assumptions and calculation of the fixed portion of the avoided cost. Column (2) contains the avoided capacity cost. The annual capital expense of the CTs is based on the real levelized fixed cost plus all O&M expenses for each year. Page 3 combines the short run avoided energy costs, the projected fuel costs for the combustion turbine, and the fixed costs assigned to energy to calculate the avoided energy costs.

PacifiCorp Loads & Resources Projectio..

1999 Avoided Cost Base Study
(Modified RAMPP-5)

	Average Megawatts	1999	2000	2001	2002	2003	2004	2005	2006
	Requirements								
1	System Retail Load (1)	5865	6033	6195	6221	6342	6461	6582	6707
2	Firm Wholesale Sales (2)	1605	1390	1039	892	836	720	548	519
3	Total	7470	7423	7234	7113	7178	7181	7131	7226
	Existing & Committed Resources (3)								
4	System Hydro Resources	543	543	543	543	543	543	543	543
5	Thermal Resources	6040	5522	5521	5521	5521	5499	5498	5498
6	Resource Efficiencies	41	48	55	62	66	70	74	78
8	Purchases & Exchanges	1079	1060	877	703	710	704	704	704
9	Demand Side Resources (4)	48	64	82	100	118	136	156	187
10	Wind	14	14	14	14	14	14	14	14
11	Total Existing & Committed Resources	7764	7252	7092	6942	6972	6967	6988	7023
12	Balance of Existing & Committed Resources	294	-171	-142	-171	-207	-214	-142	-203

Footnotes:
(1) Source RAMPP-5 Report
(2) Source RAMPP-5 Report planning assumptions revised for new/renegotiated contracts.
(3) Source RAMPP-5 Report planning assumptions revised for new contracts
(4) Source RAMPP-5 Report

PacifiCorp Loads & Resources Projection

1999 Avoided Cost Base Study
(Modified RAMPP-5)

	Winter Peak - Megawatts	1999	2000	2001	2002	2003	2004	2005	2006
	Requirements								
1	System Retail Load (1)	7617	7830	8042	8259	8242	8435	8596	8754
2	Firm Sales (2)	2533	2312	1875	1404	1221	1016	793	785
3	Total	10150	10141	9917	9663	9463	9451	9389	9539
	Existing & Committed Resources (3)								
4	System Hydro Resources	932	932	932	932	932	932	932	932
5	Thermal Resources	7232	6604	6604	6604	6604	6369	6369	6369
6	Resource Efficiencies	41	100	100	100	100	100	100	100
8	Purchases & Exchanges	3324	3450	3260	3006	3021	2306	2310	2314
9	Demand Side Resources (4)	66	89	112	137	161	186	213	254
10	Wind	41	41	41	41	41	41	41	41
11	Total Existing & Committed Resources	11637	11216	11049	10820	10859	9934	9965	10010
	Reserve Requirement								
12	Reserve	930	930	930	930	930	930	930	930
13	(Reserve+Balance)/Requirements	15%	11%	11%	12%	15%	5%	6%	5%
14	**Balance of Existing & Committed Resources**	557	144	202	226	466	-447	-354	-459

Footnotes:
(1) Source RAMPP-5 Report
(2) Source RAMPP-5 Report planning assumptions revised for new/renegotiated contracts.
(3) Source RAMPP-5 Report planning assumptions revised for new contracts
(4) Source RAMPP-5 Report

PacifiCorp Loads & Resources Projection

1999 Avoided Cost Base Study
(Modified RAMPP-5)

	Summer Peak - Megawatts	1999	2000	2001	2002	2003	2004	2005	2006
	System Load								
1	System Retail Load (1)	7712	7931	8169	8379	8413	8565	8715	8887
2	Firm Wholesale Sales (2)	2057	1803	1524	1376	1261	1031	800	800
3	Total	9770	9734	9693	9755	9674	9596	9515	9687
	Existing & Committed Resources (3)								
4	System Hydro Resources	924	924	924	924	924	924	924	924
5	Thermal Resources	7240	6604	6604	6604	6604	6369	6369	6369
6	Resource Efficiencies	41	48	55	62	66	70	74	78
8	Purchases & Exchanges	2397	2219	2198	1934	1651	1501	1501	1501
10	Demand Side Resources	66	89	112	137	161	186	213	254
14	Wind	41	41	41	41	41	41	41	41
17	Total Existing & Committed Resources	10710	9925	9934	9703	9447	9091	9122	9167
	Reserve Requirement								
18	Reserve	930	930	930	930	930	930	930	930
19	(Reserve+Balance)/Requirements	10%	2%	2%	-1%	-2%	-5%	-4%	-5%
20	Balance of Existing & Committed Resources	10	-739	-689	-982	-1157	-1435	-1323	-1450

Footnotes:
(1) Source RAMPP-5 Report
(2) Source RAMPP-5 Report planning assumptions revised for new/renegotiated contracts.
(3) Source RAMPP-5 Report planning assumptions revised for new contracts
(4) Source RAMPP-5 Report

PacifiCorp

Attachment 2

RAMPP-5 Updated
1999 Avoided Cost Prices for Purchase Power
Summary of PD/Mac Avoided Cost Output
Mills/kWh

						Mills/kWh							
Operating Year	31 Jul	31 Aug	30 Sep	31 Oct	30 Nov	31 Dec	31 Jan	28 Feb	31 Mar	30 Apr	31 May	30 Jun	OPER-YR AVG
1998-99							18.43	15.92	16.10	18.14	14.16	13.57	7.96
1999-00	11.53	17.11	19.59	15.92	16.09	18.51							8.29

Calendar Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	OPER-YR AVG
1999	18.43	15.92	16.10	18.14	14.16	13.57	11.53	17.11	19.59	15.92	16.09	18.51	16.25

	Non-firm Energy Prices		
Deliveries During Calendar Year	Winter ¢/kWh	Summer ¢/kWh	Average ¢/kWh
1999	1.72	1.53	1.62

Seasonally Differentiated
Summer months are May-October
Winter Months are November - April

Source: Produced as the difference of two Production Dispatch Model (PD/Mac) runs: A base case including existing and committed resources, and a comparison run which includes a 50 MWa zero cost resource as a proxy for QF generation.

Each monthly figure represents the change in net power cost divided by the 50 MWa resource

Based on updated RAMPP-5 information

Attachment 3

PacifiCorp
1999 Avoided Costs
RAMPP 5
Nominal Gas Price Forecast

	Fuel Cost MMBtu /1	Fuel Escalation Rate
1999	1.69	
2000	1.77	4.73%
2001	1.85	4.52%
2002	1.93	4.32%
2003	2.06	6.74%
2004	2.15	4.37%
2005	2.24	4.19%
2006	2.34	4.46%
2007	2.44	4.27%
2008	2.69	10.25%
2009	2.78	3.35%
2010	2.88	3.60%
2011	2.98	3.47%
2012	3.09	3.69%
2013	3.19	3.24%
2014	3.31	3.76%
2015	3.43	3.63%
2016	3.55	3.50%
2017	3.68	3.66%
2018	3.81	3.66%
2019	3.95	3.66%
2020	4.10	3.66%
2021	4.25	3.66%
2022	4.40	3.66%
2023	4.57	3.66%
2024	4.73	3.66%
2025	4.91	3.66%
2026	5.09	3.66%
2027	5.27	3.66%
2028	5.47	3.66%
2029	5.67	3.66%
2030	5.87	3.66%
2031	6.09	3.66%
2032	6.31	3.66%
2033	6.54	3.66%
2034	6.78	3.66%

/1 RAMPP-5 Chapter 4, Table 4-15

Attachment 4

PacifiCorp
1999 CCCT COSTS
RAMPP-5
Summary

	Year	Avoided Firm Capacity Costs ($/kW-mo) (1)	Avoided Energy Costs $/MWh (2)	Total Avoided Costs 75% CF $/MWh (3)	Total Avoided Costs 85% CF $/MWh (4)	Total Avoided Costs 95% CF $/MWh (5)
1	1999	0.00	16.25	16.25	16.25	16.25
2	2000	4.05	16.39	23.79	22.92	22.23
3	2001	4.18	17.06	24.69	23.79	23.08
4	2002	4.30	17.74	25.59	24.67	23.94
5	2003	4.43	18.75	26.84	25.89	25.14
6	2004	4.56	19.50	27.84	26.86	26.08
7	2005	4.70	20.26	28.84	27.83	27.04
8	2006	4.84	21.09	29.93	28.89	28.07
9	2007	4.99	21.92	31.02	29.95	29.11
10	2008	5.13	23.76	33.14	32.04	31.17
11	2009	5.29	24.54	34.20	33.06	32.16
12	2010	5.45	25.38	35.33	34.16	33.24
13	2011	5.61	26.24	36.49	35.28	34.33
14	2012	5.78	27.16	37.72	36.48	35.50
15	2013	5.95	28.03	38.90	37.62	36.61
16	2014	6.13	29.03	40.23	38.91	37.87
17	2015	6.32	30.04	41.57	40.22	39.15
18	2016	6.50	31.05	42.94	41.54	40.43
19	2017	6.70	32.14	44.38	42.94	41.80
20	2018	6.90	33.27	45.88	44.39	43.22
21	2019	7.11	34.44	47.42	45.89	44.69
22	2020	7.32	35.65	49.02	47.45	46.20
23	2021	7.54	36.90	50.67	49.05	47.77
24	2022	7.77	38.19	52.38	50.71	49.39
25	2023	8.00	39.54	54.15	52.43	51.07
26	2024	8.24	40.92	55.97	54.20	52.81
27	2025	8.49	42.36	57.86	56.04	54.60
28	2026	8.74	43.85	59.82	57.94	56.46
29	2027	9.00	45.39	61.84	59.90	58.37
30	2028	9.27	46.99	63.93	61.93	60.36
31	2029	9.55	48.64	66.09	64.03	62.41
32	2030	9.84	50.35	68.32	66.21	64.54
33	2031	10.13	52.12	70.63	68.45	66.73
34	2032	10.44	53.95	73.02	70.78	69.01
35	2033	10.75	55.85	75.49	73.18	71.36

Column Notes:

(1) The fixed cost of a simple cyle combustion turbine.

(2) Combined cycle fuel cost and capitalized fixed cost of a combined cycle combustion turbine which is in excess of a simple cycle combustion turbine.

(3) Combined costs, assuming a 75% capacity factor.

(4) Combined costs, assuming a 85% capacity factor.

(5) Combined costs, assuming a 95% capacity factor.

Attachment 4

PacifiCorp

1999 CCCT COSTS

RAMPP-5

Calculation of Avoided Capacity and Capitalized Energy Costs

Cost of capital	10.26%
Discount Rate	9.08%
Inflation rate	3.00%
Real Discount Rate	5.90%

Simple cycle CT		Combined cycle CT		
1998 Capital	$390 /kW	1998 Capital	$475 /kW	
Carrying Charge	9.58%	Carrying Charge	9.36%	(assume 35 year book life for CCCT)
Non-Fuel O&M	8.49 /kW	Non-Fuel O&M	33.17 /kW	(assume 30 year book life for SCCT)

	Year	Simple Cycle Fixed Costs ($/kW-yr) (1)	Simple Cycle Fixed Costs ($/kW-mo) (2)	Combined Cycle Fixed Costs ($/kW-yr) (3)	Combined Cycle Fixed Costs ($/kW-mo) (4)	Capitalized Energy Cost ($/kW-mo) 4) - (2) = (5)	Capitalized Energy Cost 85% CF ($/MWh) (6)
1	1999	47.23		79.96		0.00	0.00
2	2000	48.64	4.05	82.36	6.86	2.81	4.53
3	2001	50.10	4.18	84.83	7.07	2.89	4.66
4	2002	51.60	4.30	87.37	7.28	2.98	4.80
5	2003	53.15	4.43	89.99	7.50	3.07	4.95
6	2004	54.75	4.56	92.69	7.72	3.16	5.10
7	2005	56.39	4.70	95.47	7.96	3.26	5.25
8	2006	58.08	4.84	98.34	8.19	3.35	5.41
9	2007	59.82	4.99	101.29	8.44	3.46	5.57
10	2008	61.62	5.13	104.33	8.69	3.56	5.74
11	2009	63.47	5.29	107.46	8.95	3.67	5.91
12	2010	65.37	5.45	110.68	9.22	3.78	6.09
13	2011	67.33	5.61	114.00	9.50	3.89	6.27
14	2012	69.35	5.78	117.42	9.79	4.01	6.46
15	2013	71.43	5.95	120.94	10.08	4.13	6.65
16	2014	73.58	6.13	124.57	10.38	4.25	6.85
17	2015	75.78	6.32	128.31	10.69	4.38	7.05
18	2016	78.06	6.50	132.16	11.01	4.51	7.27
19	2017	80.40	6.70	136.12	11.34	4.64	7.48
20	2018	82.81	6.90	140.21	11.68	4.78	7.71
21	2019	85.29	7.11	144.41	12.03	4.93	7.94
22	2020	87.85	7.32	148.75	12.40	5.07	8.18
23	2021	90.49	7.54	153.21	12.77	5.23	8.42
24	2022	93.20	7.77	157.81	13.15	5.38	8.68
25	2023	96.00	8.00	162.54	13.54	5.55	8.94
26	2024	98.88	8.24	167.42	13.95	5.71	9.20
27	2025	101.85	8.49	172.44	14.37	5.88	9.48
28	2026	104.90	8.74	177.61	14.80	6.06	9.77
29	2027	108.05	9.00	182.94	15.24	6.24	10.06
30	2028	111.29	9.27	188.43	15.70	6.43	10.36
31	2029	114.63	9.55	194.08	16.17	6.62	10.67
32	2030	118.07	9.84	199.90	16.66	6.82	10.99
33	2031	121.61	10.13	205.90	17.16	7.02	11.32
34	2032	125.26	10.44	212.08	17.67	7.24	11.66
35	2033	129.01	10.75	218.44	18.20	7.45	12.01

Column Notes:

(1) Real levelized annual cost of simple cycle CT, represents the capacity portion of fixed avoided costs.
(2) Columm (1) divided by 12.
(3) Real levelized annual cost of combined cycle CT.
(4) Columm (3) divided by 12.
(5) Column (4) minus Column (2), represents the portion of fixed costs assigned to energy.
(6) Equal to Column (5), converted to $/MWh assuming the stated capacity factor.

Attachment 4

PacifiCorp

1999 CCCT COSTS

RAMPP-5

	Year	Avoided Fuel or Purchase Cost (\$/MWh) (1)	Updated Gas Price (\$/MBtu) (2)	CCCT Energy Costs 6701 Btu/kWh (\$/MWh) (3)	Variable Avoided Energy Cost (\$/MWh) (1) + (3) =(4)	Capitalized Energy Cost 85% CF (\$/MWh) (5)	Total Avoided Energy Cost (\$/MWh) (4) + (5) =(6)
1	1999	16.25	1.69		16.25		16.25
2	2000		1.77	11.86	11.86	4.53	16.39
3	2001		1.85	12.40	12.40	4.66	17.06
4	2002		1.93	12.93	12.93	4.80	17.74
5	2003		2.06	13.80	13.80	4.95	18.75
6	2004		2.15	14.41	14.41	5.10	19.50
7	2005		2.24	15.01	15.01	5.25	20.26
8	2006		2.34	15.68	15.68	5.41	21.09
9	2007		2.44	16.35	16.35	5.57	21.92
10	2008		2.69	18.03	18.03	5.74	23.76
11	2009		2.78	18.63	18.63	5.91	24.54
12	2010		2.88	19.30	19.30	6.09	25.38
13	2011		2.98	19.97	19.97	6.27	26.24
14	2012		3.09	20.71	20.71	6.46	27.16
15	2013		3.19	21.38	21.38	6.65	28.03
16	2014		3.31	22.18	22.18	6.85	29.03
17	2015		3.43	22.98	22.98	7.05	30.04
18	2016		3.55	23.79	23.79	7.27	31.05
19	2017		3.68	24.66	24.66	7.48	32.14
20	2018		3.81	25.56	25.56	7.71	33.27
21	2019		3.95	26.50	26.50	7.94	34.44
22	2020		4.10	27.47	27.47	8.18	35.65
23	2021		4.25	28.48	28.48	8.42	36.90
24	2022		4.40	29.52	29.52	8.68	38.19
25	2023		4.57	30.60	30.60	8.94	39.54
26	2024		4.73	31.72	31.72	9.20	40.92
27	2025		4.91	32.88	32.88	9.48	42.36
28	2026		5.09	34.08	34.08	9.77	43.85
29	2027		5.27	35.33	35.33	10.06	45.39
30	2028		5.47	36.63	36.63	10.36	46.99
31	2029		5.67	37.97	37.97	10.67	48.64
32	2030		5.87	39.36	39.36	10.99	50.35
33	2031		6.09	40.80	40.80	11.32	52.12
34	2032		6.31	42.29	42.29	11.66	53.95
35	2033		6.54	43.84	43.84	12.01	55.85

(2) Fuel cost of large combined cycle combustion turbine.
(3) Total avoided variable energy costs, Column (1)+column(3)+ Column(4)
(4) Fixed energy costs, fixed cost of CCCT less fixed cost SCCT
(5) Total avoided energy costs, Column(5) + Column (6)

PacifiCorp

1999 CCCT COSTS

RAMPP-5

	Year	RAMMP-5 Avoided Cost 85% CF (¢/kWh) (1)	RAMMP-4 Updated Avoided Cost 85% CF (¢/kWh) (2)	Difference (¢/kWh) (3)
1	1999	1.62	1.46	0.17
2	2000	2.29	1.47	0.82
3	2001	2.38	1.51	0.87
4	2002	2.47	1.57	0.90
5	2003	2.59	1.63	0.96
6	2004	2.69	1.76	0.93
7	2005	2.78	1.81	0.98
8	2006	2.89	2.07	0.82
9	2007	3.00	2.10	0.90
10	2008	3.20	2.37	0.84
11	2009	3.31	2.79	0.52
12	2010	3.42	3.71	-0.29
13	2011	3.53	3.84	-0.31
14	2012	3.65	3.97	-0.32
15	2013	3.76	4.11	-0.34
16	2014	3.89	4.25	-0.36
17	2015	4.02	4.39	-0.37
18	2016	4.15	4.55	-0.39
19	2017	4.29	4.70	-0.41
20	2018	4.44	4.87	-0.43
21	2019	4.59	5.04	-0.45
22	2020	4.74	5.21	-0.47
23	2021	4.91	5.39	-0.49
24	2022	5.07	5.58	-0.51
25	2023	5.24	5.78	-0.53
26	2024	5.42	5.98	-0.56
27	2025	5.60	6.19	-0.58
28	2026	5.79	6.40	-0.61
29	2027	5.99	6.63	-0.64
30	2028	6.19	6.86	-0.66

	(1)	(2)	(3)
20 Year Net Present Value:	26.01	21.59	
20-year Nominal Levelized	2.87	2.38	0.49
20-year Real Levelized	2.25	1.87	0.38
30 Year Net Present Value:	31.89	28.07	
30-year Nominal Levelized	3.13	2.75	0.37
30-year Real Levelized	2.29	2.02	0.27
Discount Rate	9.08%		
Real Discount Rate	5.90%		

Computation of On- & Off-Peak Energy Prices to Yield Weighted Average Equal to Annual Average

	1999 Winter		1999 Summer	
Annual Average Energy A/C -- from PD/Mac runs or CCCT (input)	20.73	mills/kWh	20.73	mills/kWh
Difference -- High Top - Low Top (input)	9.72	mills/kWh	9.72	mills/kWh
% of hours on peak (input)	57.00%		57.00%	
% of hours off peak (input)	43.00%		43.00%	
On-peak weight = 100% - % hours on peak	43.00%		43.00%	
Off-peak weight = 100% - % hours off peak	57.00%		57.00%	
Add to Annual Average for On-peak = On-peak weight * Difference	4.18	mills/kWh	4.18	mills/kWh
Subtract from Annual Average for Off-peak = Off-peak weight * Difference	5.54	mills/kWh	5.54	mills/kWh
Sum of Added & Subtracted Amounts	9.72	mills/kWh	9.72	mills/kWh
On-peak = Annual Average + On-peak Adder	24.91	mills/kWh	24.91	mills/kWh
Off-peak = Annual Average - Off-peak Subtractor	15.19	mills/kWh	15.19	mills/kWh
Weighted Average of On-Peak & Off-Peak (weighted by hours on & off peak)	20.73	mills/kWh	20.73	mills/kWh

Annual Average (weighted by hours in season) Winter Hours: 4344 Summer Hours: 4416 **20.73 mills/kWh**