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Memorandum

To: Public Service Commission
Ric Campbell, Chair
Connie White, Commissioner
Ted Boyer, Commissioner

From: Division of Public Utilities
Irene Rees, Director
Judith Johnson, Energy Section Manager
Artie Powell, Technical Consultant

Date: April 6, 2004

Subject: Schedule 37, Docket No. 03-035-T10

ISSUE

On or about September 12, 2003 PacifiCorp filed proposed changes to Schedule 37. This schedule provides the standard avoided cost rates for purchases from qualifying facilities ("QFs") with a capacity of less than one megawatt. According to PacifiCorp's application, the updated avoided costs were consistent with the acknowledged IRP and followed the three-stage methodology ordered by the Commission in Docket 01-2035-01. The Division of Public Utilities (the "Division") recommended adoption of these rates. The Committee of Consumer Services (the "Committee"), however, recommended "the Commission take no action until PacifiCorp's assumptions … can be compared to those used in the Next Best Alternative ("NBA") for RFP-2003A."[1] The Commission, based on PacifiCorp's forecasted load and resource balance, denied the proposed changes and ordered PacifiCorp to re-file its avoided costs using the avoided cost method approved in Docket No. 94-2035-03. PacifiCorp refilled its avoided costs on or about January 30, 2004. This memo provides the Division's analysis of PacifiCorp's latest filing and recommendation to the Commission.

[1] Committee of Consumer Services, Memo dated 4 November 2003, Docket 03-035-T10.

In addition to PacifiCorp's application, a group consisting of The Utah Energy Office, Wind Tower Composites LLC, Utah Clean Energy Alliance, Wasatch Clean Air Coalition, Renewable Energy Development Corporation, and Tasco Engineering (the "Petitioners") filed a petition requesting the Commission revise Schedule 37 increasing the limit from 1-MW to 5-MW for wind-powered resources. This petition was filed on or about January 30, 2004. This memo also contains the Division's initial comments and recommendation concerning increasing the megawatt limit contained in Schedule 37.

RECOMMENDATION

With some minor adjustments discussed herein, the Division recommends the adoption of the avoided cost rates as the basis for payments to QFs of less than 1 MW. The Division also recommends that the limit be increased to 5 MW on an experimental basis with no restrictions on fuel type. The Division further recommends that a total 25 MW maximum for new small QF projects be used before the rates must be updated. The Division proposes that the experiment run for two-years at the end of which the Division will report to the Commission.

DISCUSSION AND ANALYSIS

Avoided Cost Calculations

On or about September 12, 2003 PacifiCorp filed proposed changes to Schedule 37. This schedule provides the standard avoided cost rates for purchases from qualifying facilities ("QFs") less than one megawatt in size. According to PacifiCorp's application, the updated avoided costs were consistent with the acknowledged IRP and followed the three-stage methodology ordered by the Commission in Docket 01-2035-01. In this methodology avoided costs are based on (i) market prices for the first twelve months, (ii) the costs of a simple cycle combustion turbine ("SCCT") for the following 22 months, and (iii) the costs of a combined cycle combustion turbine ("CCCT") thereafter. The Commission adopted the three-stage methodology in Docket No. 01-2035-01. In that docket, however, PacifiCorp was peak and energy deficient in all years. According to PacifiCorp's September filing, its load and resource balance is, on average, sufficient until 2007 – the winter peak is sufficient until 2008, while the summer peak is deficient starting in 2003. According to the Commission's order in Docket 94-2035-03, a proxy plant method[2] should be used for years when PacifiCorp's load and resource balance is deficient and a differential revenue method should be used when PacifiCorp's load and resource balance is sufficient. Consequently, the Commission ordered PacifiCorp to re-file its avoided costs using a differential revenue method for the period of sufficiency and a proxy plant method for the period of deficiency. PacifiCorp re-filed its avoided cost on January 30, 2004.

The Division notes that PacifiCorp is, according to its filing, resource deficient for all years in the summer, but doesn't require resources in the winter until 2008. Accordingly, PacifiCorp's avoided costs should be based on the proxy plant method post-2007 when PacifiCorp is resource deficient in all years and seasons. In the years between 2004 and June 2007 (inclusive) PacifiCorp's costs should combine the proxy plant method for the summer months when it is resource deficient and the differential revenue method for the winter months when it is resource sufficient. (See Table 1).

A review of PacifiCorp's filing indicates that this is indeed what PacifiCorp has done in its re-filing of avoided costs. On page one of the re-filed proposed avoided costs PacifiCorp states,

> [T]he avoided cost calculation is separated into two distinct periods: (1) the Short Run – the period of energy sufficiency (2004-June 2007) in which avoided costs are based on the marginal production cost of existing resources **plus** the cost of purchasing summer capacity; and (2) the Long Run – the period (July 2007 and beyond) in which new resources are to provide both summer and winter capacity and energy to meet the Company's resource requirements.[3]

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[2] The proxy plant method includes short-term capacity purchases.

[3] "PacifiCorp's Avoided Cost Calculation," Schedule 37 – Avoided Cost Purchases from Qualifying Facilities, Docket 03-035-T10, January 10, 2004, p. 1. (Emphasis added).

Table 1: Avoided Cost Methodology

	Load and Resource Balance		**Methodology**
Year	Summer	Winter	Differential Revenue/ Proxy Plant
2003	Deficient	Sufficient	Combined
2004	Deficient	Sufficient	Combined
2005	Deficient	Sufficient	Combined
2006	Deficient	Sufficient	Combined
2007	Deficient	Sufficient	Combined
2008	**Deficient**	**Deficient**	Proxy Plant
⋮	⋮	⋮	⋮
2028	**Deficient**	**Deficient**	Proxy Plant

1. Short-Run Avoided Costs, 2004 through June 2007

In the short-run, during periods of resource sufficiency, avoided costs are based on two production cost studies or two runs of the GRID model. The first run, or base case, is completed with the Company's existing power purchases and thermal resources. The second run includes a 10 Mw (zero cost) resource. The difference between the studies provides the energy only, or off-peak, price for the period.[4]

During periods of resource (capacity) deficiency, namely June through August, the capacity price is determined by the proxy plant method. In this case, the proxy plant is assumed to be Currant Creek's SCCT. Since the published avoided costs rates are annual and not monthly rates, and since the proxy plant is utilized for only three months of the year, PacifiCorp uses

[4] *Ibid.* Table 2, Off-Peak Prices.

¼ of the total capacity value as the capacity price for an annual payment. The on-peak price is then the capacity price plus the off-peak price.[5]

Table 2: Short-Run Avoided Cost Calculations

Off-Peak	GRID(With 10 MW Resource) – GRID(Without 10 MW Resource)
On-Peak	Off-Peak + ¼ *(Annual Capacity Value of SCCT)*(8,760*CF)

2. Long-Run Avoided Costs, July 2007 and Beyond

In the long-run, July 2007 and beyond, when the Company is resource deficient and needs capacity and energy both in the winter and summer, avoided costs are based on the cost of a combined cycle combustion turbine, Currant Creek.[6] The avoided cost calculations include both energy and capacity costs. The capacity cost is assumed to be equivalent to the fixed costs of the underlying SCCT. Any fixed costs associated with the CCCT beyond those of the SCCT are rolled into the total energy costs.[7]

Key Assumptions

1. Gas Prices

Gas prices used in this filing are the Company's official "Market Price Projections." These prices are a blend of the Company's market gas curve and the gas prices used in the Midas model. The exact blend is described on page 3 of the Company's filing.

PacifiCorp's gas prices begin in 2004 at approximately [CONFIDENTIAL] /MMBtu and decline to approximately [CONFIDENTIAL] in 2011, an average annual decrease of about 3%. From 2012 to 2028 gas prices increase from [CONFIDENTIAL] to approximately [CONFIDENTIAL], an average annual increase of approximately 2.8%. Overall,

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[5] *Ibid.* Table 2, On-Peak Prices.

[6] The avoided cost calculations for 2007 are based on 6 months of the short-run costs and 6 months of the long-run costs.

[7] *Op.cit.,* "PacifiCorp's Avoided Cost Calculation," Table 3, Capitalized Energy Costs.

PacifiCorp's gas prices increase by approximately [CONFIDENTIAL] per year on average. This pattern is different from the pattern seen in EIA's gas price forecast.

In EIA's forecast,[8] prices decline by about 1% per year from 2004 to 2011, and then increase by approximately 1% per year from 2012 to 2025. From 2011 to 2016, the increase in EIA's forecast is roughly the same as PacifiCorp's, about 3%. From 2016 to 2025, however, EIA's forecast levels out at approximately $5, whereas, PacifiCorp's forecast continues to escalate. A comparison of the two forecasts reveals that in the early years, from 2004 to 2008, PacifiCorp's forecast is slightly higher than EIAs; for the middle years, from 2009 to 2018, PacifiCorp is slightly lower than EIA; and for the later years, PacifiCorp's forecast is higher. (See Figure 1).

Figure 1: Comparison of PacifiCorp and EIA Gas Forecasts [CONFIDENTIAL]

The difference between PacifiCorp and EIA's forecasts range from [CONFIDENTIAL]. Overall, however, PacifiCorp and EIA's forecasts differ by only approximately [CONFIDENTIAL] on average per year. Thus, using an EIA type forecast would have little affect on the avoided costs. In fact using EIA's forecast only changes the 20-year levelized total cost from ¢4.66 to ¢4.70/kWh, a change of less than 1%.

2. Resource Costs

In its original comments to this docket, the Committee argued that, "The information used in PacifiCorp's NBA should reflect its best commercial estimate of constructing" a new plant. PacifiCorp's most recent filing indicates that the costing information for the proxy plant is that of Currant Creek. (See Table 8, page 3). However, in response to DPU data request 2.5, PacifiCorp explained that, "The proposed rates are not based on either the Currant Creek project under construction or the expansion of that project. They are based on an additional Greenfield unit located within the 'Utah Bubble'."[9] In its order rejecting the originally filed

[8] Energy Information Administration Web site, http://www.eia.doe.gov/oiaf/aeo/gas.html.

[9] PacifiCorp's response to DPU Date Request 2.5, Docket No. 03-035-T10, March 18, 2004.

QF rates, the Commission (quoting from an earlier order) states, "Avoided costs will change as economic and financial circumstances affecting them do."[10] The Division anticipated that the re-filed QF rates would reflect Currant Creek's costs and not the older IRP estimates for a SCCT and CCCT plant.[11]

In testimony, on behalf of PacifiCorp (Docket No. 03-035-29), Rand Thurgood indicated that the costs associated with Currant Creek were [CONFIDENTIAL] per kW-year for fixed O&M, [CONFIDENTIAL] per MWh for variable O&M in combined cycle mode, and [CONFIDENTIAL] per MWh variable O&M for the duct firing.[12] In contrast, in its filing for this case (Docket No. 03-035-T10), PacifiCorp proposes a fixed O&M cost of [CONFIDENTIAL] per kW-year and variable O&M costs of [CONFIDENTIAL] and [CONFIDENTIAL] per MWh respectively for the combined cycle and duct firing portions of the proxy plant. If Currant Creek's costs[13] are used in the QF rate calculations, the total levelized price increases from that proposed by PacifiCorp, ¢4.66/kWh, to ¢4.70/kWh, an increase of less than 1%.

3. Heat Rates

The heat rates proposed and used by PacifiCorp in its re-filed QF rates are also slightly different from those reported for Currant Creek. PacifiCorp uses respectively [CONFIDENTIAL] and [CONFIDENTIAL] for the heat rates for the SCCT and CCCT. The heat rates for Currant Creek are [CONFIDENTIAL] for the SCCT and a weighted average heat rate of [CONFIDENTIAL] for the CCCT/duct firing. However, adjusting the heat rates has no significant affect on the calculated QF rates.

4. Load and Resource Balance

[10] Commission Order, Docket No. 03-035-T10, November 21, 2003, p. 5.

[11] The capacity sizes for the SCCT and CCCT used by PacifiCorp in developing the proposed QF rates are equivalent to Currant Creek. (See Table 8 of PacifiCorp's re-filed rates). This supports the Division's argument that the costs should be the same as those for Currant Creek.

[12] Direct Testimony of J. Rand Thurgood, Docket No. 03-035-29, November 2003, pp. 18-19.

[13] Mr. Thurgood's testimony does not provide separate O&M costs for Currant Creek over the period when the plant operates in SCCT mode. However, since the QF rates only depend on the SCCT for a couple of years, any differences in the rates due to more accurate cost estimates would be negligible.

In a recent update to its IRP, PacifiCorp estimates that the load/resource deficit for the summer of 2005 will be approximately 1,049 MW. However, in Table 1 of its re-filed QF rates the summer deficit for 2005 is reported as 694 MW. In response to a data request,[14] PacifiCorp explained that this apparent difference is the result of three factors. First, the data used in the QF filing is more recent and reflects the system resource balance, whereas the IRP update reflects the east-side (Utah) portion of PacifiCorp's system. Second, The avoided costs calculations reflect the Currant Creek project. Finally, the avoided cost analysis uses an August peak whereas the IRP update uses a July peak. While these differences affect the magnitudes of the load and resource balance, since the timing of resource deficits is not affected, these differences appear to have a negligible affect on the QF rates.

5. Discount Rates and Payment Factors

The discount rates, with the exception of that used in calculating the payment factors, are those used in the IRP, 7.52%. The discount rate used in deriving the payment factors in Table 8 of PacifiCorp's filing is 7.5%. Adjusting the discount rate, however, does not significantly affect the avoided costs rates.

Avoided Costs Rates

1. PacifiCorp's Proposed Rates

The rates proposed by PacifiCorp are, on a total or all-in price, about 12% higher than the current authorized rates for Schedule 37. (See Table 3 below).

Table 3: Proposed Avoided Cost Prices

			Peak Energy		Off-Peak Energy		Total Price
	Capacity	Energy (Avg)	Winter	Summer	Winter	Summer	85% CF
	$/kW-Month	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh	¢/kWh
Current	5.99	3.21	4.99	4.99	3.23	3.19	4.17
First Proposed	6.04	3.62	5.5	5.43	3.68	3.56	4.65
Second Proposed	6.49	3.61	5.36	5.53	3.55	3.68	4.66
% Change From Current Approved Rates							
First Proposed	0.83%	12.77%	10.22%	8.82%	13.93%	11.60%	11.51%
Second Proposed	8.35%	12.46%	7.41%	10.82%	9.91%	15.36%	11.75%

[14] PacifiCorp's response to DPU date request 1.9, Docket No. 03-035-14.

The current total price (at an 85% capacity factor) is ¢4.17. The proposed rate is ¢4.66. However, this proposed rate does not reflect any of the adjustments discussed above. For example, this proposed rate does not reflect the more recent cost estimates for Currant Creek.

2. Division Adjustments

The Division recommends four adjustments to the avoided cost rates filed by PacifiCorp. Taken together, the adjustments increase the total avoided cost rate by approximately 1.3%. See Table 4 below for a summary of the Division's adjustments.

(a) Payment Factors

The intent, according to PacifiCorp, of the payment factor "is to determine the revenue requirement stream to the utility necessary to exactly recover the costs of an assumed $100,000 investment."[15] Assuming a $100,000 investment, and given the Companies tax rates, capital structure, costs of capital, and other assumptions a stream of yearly costs is calculated. The present value of this stream of costs is then levelized using a real discount rate. The payment factor is then the ratio of the levelized payment to the $100,000 investment. While adjusting the discount rate for the payment factors has no appreciable effect on the Avoided cost rates, the Division believes these discount rates should be consistent.

The payment factors used by PacifiCorp and reported in Table 8 of its filing are for the SCCT and CCCT respectively 9.7% and 8.7%. However, as previously noted, these factors are based on a 7.5% discount rate, whereas, the discount rate used in other calculations in deriving the avoided costs rates, as well as in the IRP, is 7.52%. If the discount rate is adjusted, the payment factors are for the SCCT and CCCT 9.45% and 8.49%.

(b) Heat Rates

The heat rates used by PacifiCorp utilized by PacifiCorp in deriving the avoided cost rates are [CONFIDENTIAL] for the SCCT; [CONFIDENTIAL] for the CCCT; and

[15] PacifiCorp's response to DPU data request 2.1, Docket No. 03-035-14, March 24, 2004.

[CONFIDENTIAL] for the duct firing. The heat rates for Currant Creek are [CONFIDENTIAL]; [CONFIDENTIAL]; and [CONFIDENTIAL] respectively. While the Division supports the Committee's contention that the most recently available information on costs and heat rates should be utilized in calculating avoided cost rates, adjusting the heat rates has no appreciable affect on the avoided cost rates in this case.

(c) SCCT & CCCT Costs

As discussed above, the fixed and variable O&M costs used by PacifiCorp for the CCCT plant are slightly different from those for Currant Creek. Adjusting the costs increases the avoided cost rates by a little less than 1%.

(d) Calculation Correction

In Table 8, page 1, under the heading 'Simple Cycle Excluding Transmission Costs," PacifiCorp reports the fixed and variable O&M costs as [CONFIDENTIAL] /kW-year and [CONFIDENTIAL] /MWh respectively. These costs are actually the O&M cost for the CCCT. Adjusting the calculations to reflect the SCCT costs increases the total avoided costs from ¢4.66/kWh to ¢4.67/kWh.

Overall, the adjustments raise the total avoided cost rate from PacifiCorp's proposed rate of ¢4.66/kWh to ¢4.72/kWh. (See Attachment A for a complete statement of the revised tariff).

Table 4: Adjusted Avoided Cost Rates

PacifiCorp's Proposed Total Price ¢4.66/kWh

Division Adjustment	Marginal Effect	Cumulative Effect	Avoided Cost Price ¢/kWh
Payment Factors	Negligible	Negligible	4.66
Heat Rates	Negligible	Negligible	4.66
O&M Costs	1.07%	1.07%	4.71
Calculation Correction	0.21%	1.29%	4.72

Raising the Limit

Currently, a QF selling power to PacifiCorp under Schedule 37 is limited in size or capacity to 1 MW or less. The Petitioners in this case have requested that this capacity limit be increased to 5 MW for wind-powered QFs. The request is based on three arguments. First, the current limit doesn't take into account the relatively low capacity factor of wind-powered resources. Second, the Petitioners claim that the change would make Schedule 37 more consistent with the Commission's IRP Standards and Guidelines. Finally, the Petitioners argue that the change will help "promote clean, efficient, and economic resource acquisition."[16]

According to the Petitioners, recent technological advancements have increased the minimal efficient scale for wind-powered resources from something less than 1 MW to approximately 1.8 MW for land-based sites and 3 MW for offshore installations. Most wind-powered resources, however, operate at approximately a 30% capacity factor, which implies that the output would be between 0.54 MW to 1 MW. Thus a wind-powered QF, taking advantage of

[16] "Petition for Tariff Revision," Docket No. 03-035-T10, p. 2.

the latest technology and economies of scale would be roughly equivalent, at least from a total output or production perspective, to a fossil fuel QF of 1 MW.

The Commission's IRP Standards and Guidelines recognize that resources differ with respect to "their dispatachability, certainty of output and risks associated with environmental externalities."[17] The Petitioners argue that increasing the limit is necessary to ensure consistent and comparable treatment between potential QF projects.

Finally, the geographical diversity of small wind projects will, according to the Petitioners, help mitigate the risk associated with fuel price volatility, and will allow for strategic location of production closer to loads within the Utah bubble, thus avoiding the transmission difficulties of bringing power into the Wasatch Front.[18]

While these arguments are compelling, PacifiCorp, in response to a data request,[19] has expressed several concerns with raising the current limit. First, PacifiCorp points out that, "The published rates are a one size fits all approach ... However, the published rates do not truly represent the costs these smaller QFs allow the Company to avoid." This is due to the difference in operating characteristics each QF has compared to the proxy plant used to derive the published rates. Second, given that the published rates do not reflect the true avoided costs, the limit of 1 MW or less minimizes any subsidy borne by retail ratepayers. If the limit were to be increased, PacifiCorp recommends that two changes be made to the methodology:

1. Increase proportionally the size of the of the 10 MW zero-cost resource used in GRID. For example, if the limit is raised to 5 MW, increase the resource to a 50 MW zero-cost resource.
2. Establish a cap on the total MW that are eligible for the standard published rates before the rates must be updated.

In the same Data response PacifiCorp calculated what the published rates would be if the limit were raised to 10 MW and the zero-cost resource were increased proportionately to 100

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[17] *Ibid.*, p. 2.

[18] "Petition for Tariff Revision," Docket No. 03-035-T10, pp. 2-3.

[19] DPU Data Request 2.2, Docket No. 03-035-T10, March 18, 2004.

MW. The "new" all-in rate would be ¢4.61/kWh, whereas, the currently proposed rate is ¢4.66/kWh.[20] This represents a change of approximately 1%. If the limit were raised to 5 MW as the Petitioners have requested the impact would be even less.

In response to a separate data request, PacifiCorp indicates that the number of QFs currently providing power under the published rates is minimal. According to PacifiCorp, there are three small QFs in Utah with a total capacity of approximately 2.2 MW. However, PacifiCorp's response indicates that there are a number of potential QFs in Utah, which total approximately 238 MW. If a limit increase were to attract a number of new wind projects and all the other potential QFs are developed, the subsidy borne by ratepayers could potentially be substantial.

Therefore, considering the Petitioner's arguments and the concerns raised by PacifiCorp, the Division recommends that the limit be increased to 5 MW on an experimental basis with no restrictions on fuel type. The Division also recommends that a total 25 MW maximum be used before the rates must be updated.[21] The Division proposes that the experiment run for two-years at the end of which the Division will report to the Commission.

CC Rea Peterson, Division of Public Utilities

John Stewart, PacifiCorp

Douglas Larson, PacifiCorp

Roger Ball, Committee of Consumer Services

Kelly Francone, Committee of Consumer Services

[20] These prices do not reflect the changes recommended by the Division in this memo.

[21] The 25 MW limit is arbitrary but allows for 5 QF projects of 5 MW or less to be integrated into the system before the rates would need to be updated.

Attachment A
Division's Revised Tariff Utah Schedule 37
Proposed Prices

Year	Capacity Price $/kW-mo	Energy Only Price ¢/kWh	On-Peak Energy Prices Winter ¢/kWh	On-Peak Energy Prices Summer ¢/kWh	Off-Peak Energy Prices Winter ¢/kWh	Off-Peak Energy Prices Summer ¢/kWh	Total Price @ 85% Capacity Factor ¢/kWh
2004	1.56	3.12	3.75	3.37	3.31	2.93	3.37
2005	1.59	4.19	4.07	5.20	3.62	4.75	4.44
2006	1.63	3.96	4.01	4.84	3.55	4.38	4.23
2007	4.46	3.60	4.55	5.17	3.55	3.65	4.32
2008	7.43	3.45	5.55	5.55	3.45	3.45	4.65
2009	7.62	3.43	5.58	5.58	3.43	3.43	4.66
2010	7.81	3.29	5.50	5.50	3.29	3.29	4.55
2011	8.00	3.30	5.56	5.56	3.30	3.30	4.59
2012	8.20	3.37	5.69	5.69	3.37	3.37	4.69
2013	8.41	3.44	5.81	5.81	3.44	3.44	4.79
2014	8.62	3.50	5.94	5.94	3.50	3.50	4.89
2015	8.83	3.59	6.09	6.09	3.59	3.59	5.01
2016	9.05	3.70	6.26	6.26	3.70	3.70	5.16
2017	9.28	3.80	6.42	6.42	3.80	3.80	5.29
2018	9.51	3.90	6.59	6.59	3.90	3.90	5.44
2019	9.75	4.01	6.77	6.77	4.01	4.01	5.58
2020	9.99	4.13	6.96	6.96	4.13	4.13	5.74
2021	10.24	4.25	7.15	7.15	4.25	4.25	5.90
2022	10.50	4.37	7.34	7.34	4.37	4.37	6.07
2023	10.76	4.49	7.54	7.54	4.49	4.49	6.23
Levelized Rate	6.55	3.66	5.43	5.60	3.59	3.73	4.72
$/MWh		36.61	54.27	56.00	35.93	37.28	47.17

Discount Rate	7.52%
Capacity Factor	85.00%