P U B L I C

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations	))))))))))	**DOCKET NO. 09-035-23** **Exhibit No. DPU 14.0** **Direct Testimony and Exhibits** **Charles E. Peterson**

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

Direct Testimony of

Charles E. Peterson

October 8, 2009

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Testimony of Charles E. Peterson

I. INTRODUCTION AND SUMMARY

Q. Please state your name, business address and title.

A. My name is Charles E. Peterson; my business address is 160 East 300 South, Salt Lake City, Utah 84114; I am a Technical Consultant in the Utah Division of Public Utilities (Division, or DPU).

Q. On whose behalf are you testifying?

A. The Division.

Q. Please summarize your educational and professional experience.

A. I attended the University of Utah and earned a B.A. in mathematics in 1978 and a Master of Statistics (M.Stat.) through the Graduate School of Business in 1980. In 1990, I earned an M.S. in economics, also from the University of Utah.

Between 1980 and 1991, I worked as an economic and financial consultant and business appraiser for several local firms or local offices of national firms. My work frequently involved litigation support consulting and I have testified as an expert witness in both federal and state courts.

In 1991, I joined the Property Tax Division of the Utah State Tax Commission. In 1992, I was promoted to manager over the Centrally Assessed Utility Valuation Section. I have provided expert testimony regarding valuation, economic and cost of capital issues, both in deposition and formal hearing before the Utah State Tax Commission.

I joined the Division in January 2005 as a Utility Analyst; in May 2006, I was promoted to Technical Consultant. I have worked primarily in the energy section of the Division. In 2007, I earned the Certified Rate of Return Analyst (CRRA) from the Society of Utility and Regulatory Financial Analysts (SURFA).

My current resume is attached as DPU Exhibit 14.1.

Q. Please outline the projects you have worked on since coming to the Division.

A. I was involved in evaluating cost of capital issues in the 2004 rate case that was settled in February 2005. I subsequently co-authored a paper regarding the Capital Asset Pricing Model (CAPM) published in *The NRRI Journal of Applied Regulation.*[1] In 2008 I co-authored an article related to ring-fencing that was published in Public Utilities Fortnightly.[2]

In 2006 I provided written and oral testimony on cost of equity supporting the stipulation that settled most issues in the PacifiCorp general rate case in Docket No. 06-035-21. In May 2008 I provided written and oral testimony on cost of capital and related issues in both the PacifiCorp and Questar Gas Company general rate cases (Docket Nos. 07-035-93 and 07-

[1] The NRRI Journal of Applied Research, vol. 3, December 2005, Ohio State University, Columbus, OH, pp. 57-70.
[2] Public Utilities Fortnightly, Vol. 146, No. 2, February 2008, pp. 32-35, 66.

057-13, respectively). Earlier in 2009 I provided written testimony and oral testimony in support of the stipulation on Cost of Capital in the PacifiCorp rate case Docket No. 08-035-38.

I have worked on DSM, HELP, and service quality and customer guarantees involving PacifiCorp. I was the Division lead on an internal research project regarding ring-fencing that resulted in a report to the Utah Public Service Commission (Commission). I was the lead of the economics and finance group within the Division assigned to evaluate the proposed acquisition (Acquisition) of PacifiCorp (Company)[3] by MidAmerican Energy Holdings Company (MEHC). Please see Docket No. 05-035-54. I testified on behalf of the Division in PacifiCorp's purchase of the Chehalis power plant on July 17, 2008 (see Docket No. 08-035-35). I have been the lead on a number of QF contract cases.

Q. What is the purpose of your testimony in this matter?

A. My testimony focuses on the total construction costs of five wind projects in Wyoming. The projects are known as Glenrock III, Seven Mile Hill II, Rolling Hills, McFadden, and High Plains. Based upon documents and answers to data requests provided by the Company, I have analyzed and compared the capital costs of these projects. I present to the Commission my analysis and conclusions regarding these costs.

[3] Rocky Mountain Power (RMP) is an operating division of PacifiCorp primarily performing the retail distribution operations of PacifiCorp in the eastern part (i.e. Utah, Wyoming and Idaho) of PacifiCorp's system. RMP runs no electric generators, and is not a separate corporate entity from PacifiCorp. Therefore, throughout this testimony I will primarily refer to PacifiCorp, rather than RMP.

Additionally, in Part III of my testimony, I estimate the additional revenue and the adjustment to the Company's revenue requirement that results from the new contract that has been negotiated with a customer referred to as "Customer B" in Company witness C. Craig Paice's exhibits.

Q. Please outline the scope of, and basis for, your testimony.

A. The scope of my testimony is limited to an analysis of the overall construction costs related to the five wind projects described earlier. During the analysis and preparation of my testimony I reviewed documents provided through discovery including the Appropriation Requests and related reports and memoranda prepared by the Company for each wind project. I also reviewed answers to other Division data-requests pertinent to these wind projects.

With respect to revenues from Customer B, I reviewed the testimony exhibits of Company witness Mr. Paice and the proposed electric service contract and supporting testimony of Customer B.

Q. What conclusions and recommendations have you reached?

A. As discussed below and set forth on Exhibit 14.4, I have concluded that an adjustment to the Company's rate base is warranted. The total system-wide adjustment is a downward adjustment of $25,300,000. The rate base reduction in Utah is about $10,400,000, rounded; the reduction in the Utah revenue requirement is calculated to be $1,270,000, rounded.

Revenues from Customer B should be increased by [redacted]. This has the effect of decreasing the Company's revenue requirement in this rate case by [redacted].

II. ANALYSIS OF WIND PROJECT COSTS

Q. Please describe the five wind sites.

A. Exhibit 14.2 sets forth the basic information used in my analysis. The five projects and their locations are listed at the right. Glenrock III and Rolling Hills are located near Glenrock, Wyoming and are approximately one mile apart from one another. High Plains and McFadden Ridge I are located near Rock River, Wyoming, and are seemingly intermingled with one another. Seven Mile Hill II is located a few miles northwest of Rock River near Medicine Bow, Wyoming.

As shown on Exhibit 14.2, the net capacity factors for these projects range from a high of [redacted] percent for Seven Mile Hill II to a low of 33.8 percent for Rolling Hills. All of the turbines installed were manufactured by General Electric and have a nameplate capacity of 1.5 megawatts. The total number of turbines at each project and the total nameplate capacity is listed in columns 4 and 5 of the Exhibit 14.2. The projects range from the relatively small size of 13 turbines for Seven Mile Hill II, to the larger projects of Rolling Hills and High Plains which have 66 turbines each. For four of the five projects, the turbines were purchased in February or March 2008; the exception is Rolling Hills whose turbines were acquired in June 2007. The average basic cost per turbine was also the same for four of the five sites at [redacted] each; the exception was again Rolling Hills for which the turbines were purchased for [redacted] each.

Columns 11 and 12 of Exhibit 14.2 set forth the latest project costs that the Division has for these projects. Column 12 shows the calculated common-size cost per kilowatt (kW) nameplate capacity.[4] As the Exhibit shows, the cost of the top four projects appears to cluster roughly in the range of [redacted] per kW. The exception is High Plains which has a cost of [redacted] per kW.

Glenrock III, Seven Mile Hill III, and Rolling Hills were placed in service on December 31, 2008. McFadden Ridge and High Plains were placed in service in September 2009.

Q. Please describe your analysis.

A. Exhibit 14.3 sets forth the adjustments and calculations I performed to analyze the cost structures of the five wind projects. In column 4 I calculated an adjusted or "effective" megawatt capacity by multiplying the nameplate capacities by the projects' net capacity factors. Column 5 gives an adjusted cost per wind turbine. The only change in column 5 from the data on Exhibit 14.2 is that Rolling Hills' per turbine cost has been set to be equal to the other projects; this, along with an adjustment to the total project cost, is done to put Rolling Hills on the same basis as the other projects with respect to turbine costs. Another way of viewing this is that this is one way of isolating the balance of plant and other construction

[4] A kilowatt is 1/1000 of a megawatt (MW). Column 12 was calculated by dividing column 11 by 1000 times column 6.

costs from the turbine costs. As can be seen in column 7, the turbine costs for all projects are set at [redacted] per kW.

The total costs (with the Rolling Hills costs per turbine set equal to the other projects) divided by the nameplate kW are set forth in column 9. The values in column 9 are the same as in Exhibit 14.2 column 12, except for Rolling Hills, which increases from [redacted] per kW [redacted] per kW due to the assumed higher cost of the turbines. With this adjustment Rolling Hills' total cost per kW goes from a little below the costs of Glenrock III, Seven Mile Hill II, and slightly above McFadden Ridge I to a little higher than those three other projects. High Plains continues to be over [redacted] per kW higher than the other four projects.

Q. Earlier you mentioned calculating an "effective" megawatt capacity. How was that calculation used?

A. In looking at wind projects economics, one must look not only at total or per turbine costs, but must also consider the relative productivity of a project based upon its net capacity factor. A more expensive project could show better economic results due to higher expected output. Thus, Column 8 of Exhibit 14.3 sets forth the adjusted total cost of per adjusted or effective capacity of the turbines. Four of the projects exhibit a fairly narrow range of [redacted] (for Glenrock III) to [redacted] (for Rolling Hills) per kW. Seven Mile Hill II is a bit of an outlier on the low side at [redacted] per kW due to its relatively high capacity factor. Rolling Hills is the highest due to its relatively low capacity factor.

Column 10 calculates the total cost per effective kW. By this measure Glenrock III and McFadden Ridge are lying between [redacted] per kW. Seven Mile Hill II again is the "winner" coming in at [redacted] per kW. Rolling Hills and High Plains both top [redacted] per kW with High Plains having the highest cost by this measure at [redacted] per kW.

Q. By evaluating the costs using the effective kW you seemingly disadvantage sites that have relatively low capacity factors. Is it the Division's intention to discourage development of less-than-optimum wind sites?

A. No. The Division recognizes that in the future, new wind site developments will typically have lower capacity factors than older sites as the better sites get developed first. At this time the Division has no intention of making downward adjustments for relatively lower capacity factors per se, as long as other measures of prudency hold such as positive net benefits and that the development of a given site was reasonably the best alternative.

The calculation of the capacity factor-adjusted costs are presented here as information. As DPU Exhibit 14.3 shows, the differences in net capacity factors can enhance or mitigate the differences in project costs.

Q. Besides the raw differences in numbers, is there any other observation you made concerning your analysis?

A. Yes. One striking aspect of the analysis is that the larger projects have higher costs per kW than the smaller ones. This is wholly unexpected since the usual assumption is that larger projects should enjoy economies of scale, that is, larger projects, while costing more on an absolute basis, should cost less on a per unit basis.[5] The table below ranks the five Wyoming projects from smallest to largest along with their adjusted per kW costs (see DPU Exhibit 14.3, column 9):

Project	Project Nameplate MW	Adjusted Total cost per kW
Seven Mile Hill II	19.5	[redacted]
McFadden Ridge I	28.5	[redacted]
Glenrock III	39.0	[redacted]
Rolling Hills	99.0	[redacted]
High Plains	99.0	[redacted]

While Rolling Hills adjusted total cost per kW is only $10 per kW (or 0.44%) higher than Glenrock III, it is almost three times the size of Glenrock III; High Plains, though the same size as Rolling Hills, has the highest costs of all. There is no indication of economies of scale: on a kW basis, the adjusted total cost of Rolling Hills and High Plains are expected to be *lower* than the smaller projects, or at the very least, equal to the smaller projects.

Q. Since McFadden Ridge and High Plains are adjacent to one another, and Rolling Hills and Glenrock III are essentially in the same location, could the smaller projects be advantaged by their locations relative to the larger projects?

[5] In support of the economies of scale arguments see American Wind Energy Association, "The Economics of Wind Energy, February 2005, p.2. www.awea.org/pubs/factsheets/EconomicsOfWind-Feb2005.pdf, last accessed October 5, 2009,
and the U.S. Department of Energy, Annual Report on U.S. Wind Power Installation, Cost, and Performance Trends: 2007, dated May 2008, p. 12.

A. While that might be one way to look at it, the Company has stated that each project is "separate and distinct" except for the happenstance of purchasing wind turbine generators for the projects at the same time.[6] The Division also understands that the Company has argued in Oregon that the sizing of Rolling Hills and Glenrock III have nothing to do with avoiding the Oregon Commission's rule of requiring RFPs for projects of 100 MW or more.[7] Therefore, the Division has no evidence from the Company to suggest that there are really two or three "big" projects rather than five separate ones. Therefore, absent information to the contrary, the Division expects that there should be economies of scale shown for the larger projects, especially when compared to the smaller projects that are located in the same geographic location.

Q. Does the Division have any other information related to what the costs of these projects should be?

A. At this time the Division has limited information regarding what the absolute costs, as opposed to relative costs should be. The U.S. Department of Energy (DOE) in its report published May 2008, indicated that the average cost of wind projects in 2008 was expected to be $1,920 per kW up $210 from 2007.[8] However, the DOE data also suggest a fairly wide range around this average which would encompass the costs of PacifiCorp's Wyoming projects. The range for the 2008 projects is not given but the costs of the sample of projects built in 2007 ranged from $1,240 per kW to $2,600 per kW. Therefore, the Division cannot conclude that the level of the project costs, i.e. about [redacted] per kW, is out of line

[6] See response to DPU Data Request 23.18.
[7] Oregon PUC, Dockets UE 199 and UE 200. For a discussion of PacifiCorp's position see Order #08-548 in Docket UE 200, pp. 8-9.
[8] U.S. Department of Energy, Op. Cit., p.21.

when compared with projects in other states. Rather, the Division is focusing on the costs that could reasonably be expected on projects that are both physically adjacent and near in time.

The Division's data requests to the Company elicited general information on project costs, but provided little insight as to why the costs on a per unit basis should be higher for the larger projects. When the Division receives additional information from the Company or from other sources regarding the cost differences discussed in this testimony, the Division reserves the right to evaluate the additional information and revise our conclusions as necessary.

Q. What conclusions have you drawn?

A. Contrary to expectations, Rolling Hills and High Plains, the largest of the five projects, have higher per-unit costs than the smaller projects. The geographic and temporal proximity to the smaller projects suggests that prudently managed, High Plains and Rolling Hills should have lower per-unit costs than the other three projects. While the Division does not at this time have sufficient information to estimate how much lower the per-unit costs should be from the smaller projects, the Division adjusts the costs to be equal to the weighted average costs of the three smallest projects: Glenrock III, Seven Mile Hill II and McFadden Ridge I, or [redacted] per kW. DPU Exhibit 14.4 sets forth the computation of this adjustment. A positive adjustment represents a reduction to rate base, a negative number represents and addition to rate base. Adjustments to the three smaller wind projects would cancel each other.

I conclude that the Utah rate base should be reduced by $10,400,000. This results in a $1,270,000 reduction in PacifiCorp's revenue requirement.

III. ADJUSTMENT OF CUSTOMER B REVENUES

Q. What Adjustment are you making to Customer B's revenues?

A. Customer B and PacifiCorp entered into an electric service contract subsequent to the filing of the rate case [redacted] the revenues in the first year from the new contract will be approximately [redacted] higher than they would have been under the old contract.

The revenue from Customer B is annualized in the test year to reflect this increase. The [redacted] increase amounts to [redacted] in additional gross revenues from Customer B. After running this revenue increase through the Company's JAM model, the Utah revenue requirement in this rate case is reduced by [redacted] The Commission will likely rule on this contract before the end of the year and, therefore, this adjustment should be altered to reflect the Commission's order, if necessary.

IV. CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your wind project analysis.

A. I have reviewed the costs of five wind projects in Wyoming that include a mix of relatively small projects and the larger, 99 MW projects. On a per unit basis, i.e. on a per kW basis, the costs of these projects range from a low of [redacted] per kW. Contrary to expectations the larger projects display a higher per unit cost than the smaller projects. Given the close geographic and temporal proximity of the large projects to the smaller projects, prudently managed larger projects should be lower than, or at least equal to, the smaller projects on a per-unit basis.

Q. What conclusion have you come to with respect to the five wind projects?

A. I conclude that the Utah rate base should be reduced by $10,400,000 as set forth in DPU Exhibit 14.4. This reduces the Utah revenue requirement by approximately $1,270,000.

Q. What is the effect of your adjustment to Customer B revenues?

A. Revenues from Customer B should be increased by [redacted]. This has the effect of decreasing the Company's revenue requirement in this rate case by [redacted]. Once the Commission rules on Customer B's contract, this adjustment can be altered to reflect the Commission's order.

Q. Does this conclude your testimony?

A. Yes.