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 Utility Service Schedules and Electric Service Regulations	)	Docket No. 09-035-23 DPU Exhibit No. 10.0

Pre-Filed Direct Testimony

of

Joni S. Zenger, Ph.D.

Wind Prudence

PUBLIC VERSION

On Behalf of the

Utah Division of Public Utilities

October 8, 2009

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I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Dr. Joni S. Zenger. I am employed by the Division of Public Utilities (Division) of the Utah Department of Commerce as a Technical Consultant.

Q. What is your business address?

A. Heber M. Wells Office Building, 160 East 300 South, Salt Lake City, Utah, 84114.

Q. On whose behalf are you testifying?

A. The Division.

Q. Please describe your education and work experience.

A. I completed my Doctorate degree in economics at the University of Utah in early 2001. Prior to that, I earned my Bachelor's degree and Master's degree, also in economics from the University of Utah. I began working for the Division in the fall of 2000. In addition, I taught various economics and statistics courses for a ten-year period from 1996 through 2006, first at the University of Utah and then at the University of Phoenix.

Q. Have you previously testified before the Public Service Commission (Commission) of Utah?

A. Yes. Please see my attached Exhibit DPU 10.1 for a complete listing and dates.

II. PURPOSE AND RECOMMENDATION

Q. What is the purpose of the testimony that you are now filing?

A. My testimony has two purposes. The first is to identify and explain an adjustment to rate base that I propose regarding the McFadden Ridge I wind project. The second is to review the prudence of certain Rocky Mountain Power (alternatively, the Company) decisions to acquire wind generating plants and to identify certain concerns to be addressed going forward as the Company continues to acquire additional wind resources.

Q. What is the Division's recommendation on those subjects?

A. The Division recommends that the [redacted] contingency fee included by the Company in its capital costs for the McFadden Ridge I wind project be disallowed in this case, and that contingency fees be disallowed in future rate cases as they are not a capital cost. Second, the Division recommends:

- The Company should consider looking at diverse wind characteristics going forward in the acquisition of its wind portfolio.
- The Company should be required to submit a notification letter to the Commission at the time that each wind plant comes in service.
- The Commission should review the Company's strategy of building 99 MW wind farms adjacent to each other as separate projects in order to avoid the solicitation process required in Oregon for major resource additions.

- The Company needs to report detailed accounting of its capital wind projects rather than lump sum capital costs in order for the Division to complete a full prudence review of future wind projects.

III. CONTINGENCY ADJUSTMENT

Q. Please summarize your rate base adjustment.

A. The Company adds a contingency cost as a line item to each wind project's capital cost appropriations. These costs are found in forms entitled "Pacific Energy Appropriation Requests for Capital Expenditure" (APR) and in PacifiCorp wind approval documents, as provided to the Division in DPU Data Request #4.1. The total project cost is included in an appropriation request that is sent to upper management for approval for each wind project. The Division asked the Company to justify its use of contingency costs as part of the capital portion of its wind projects. The Company responded to DPU Confidential Data Request #23.32 as follows:

The Division recommends disallowing the [redacted] contingency cost on the McFadden Ridge I project as well as all future contingency costs that are not already built into contracts on a going forward basis. For this case, the contingency adjustment is [redacted] with a total Utah revenue requirement impact of [redacted].[1] Because all of the other wind plants considered in this rate case have now gone into service, their actual final costs have now been booked into plant-in-service accounts. For McFadden Ridge I, the contingency cost is merely speculative and may never be realized. When final costs for the project are known, these full costs (assuming they are prudent) should then be included in rate base for future rate cases.

Q. Will you describe the capital costs associated with the Company's wind projects?

A. Wind projects are basically turn-key projects. The majority of the costs are incurred in the wind turbine generator agreement and in the Balance of Plant (BOP) contract. There are also administrative costs, transmission substation charges, capital surcharges, access roads and communications charges, network integration charges, and other miscellaneous costs relating to getting the wind-generated power to the grid.

Turbine supply agreements and BOP contracts have extensive contingency clauses built in them in the form of vendor guarantees, damage provisions, project milestones, liability clauses, and so on. As turn-key projects, there is no need to budget for an additional contingency cost. These contingency costs appear essentially to be a device by which to

[1] Please see DPU Confidential Exhibit 10.2 for the calculation of the contingency adjustment on the revenue requirement.

avoid having to ask for another appropriation request from upper management if there are cost overruns.

The contingency costs that have been included as capital costs for projects that went into service during the base year for this rate case are listed below, along with the associated size of the project.

	MW	Contingency
McFadden Ridge I	28.5	$1,100,000
High Plains	99	5,544,000
Seven Mile II	19.5	487,500
Rolling Hills	99	2,000,000
Glenrock III	39	975,000
Total		$10,106,500

The Division currently has an outstanding data request to determine how much of the prior contingency costs were actually used (that is, whether any unanticipated costs are included in the final project cost of each wind project). The Division will study the responses to these data requests and may have additional recommendations regarding the inclusion of contingency funds in rate base. As I previously stated, I recommend disallowing the [redacted] McFadden Ridge contingency cost in this case.

The Company has acquired or built more than ten wind farms to date, including purchasing the turbines, finding a BOP contractor, acquiring land leases, and other project work. The capital costs for wind projects should be part of the Company's overall expenditure budget and should be forecasted as accurately as possible, as other capital

expenditures are treated. Ratepayers should not be required to pay the capital costs of speculative expenses that may or may not be incurred in the construction of a wind project.

IV. CONCERNS AND RECOMMENDATIONS REGARDING THE PRUDENCE OF WIND PROJECTS

Q. Did the Division review the prudence of the Company's decision to acquire the McFadden Ridge I plant?

A. Yes. We first reviewed the testimony of Company witness, Mr. Lasich, who requested a favorable prudence review of only the McFadden Ridge I project in this particular general rate case and asked that all associated project costs be placed into rate base.[2] However, the Division also looked at the Glenrock III, Rolling Hills, Seven Mile Hill II, and High Plains wind projects that were built during the base year. We looked at project need, capital costs, operating and maintenance (O&M) expenses, the decision process to move forward or cancel projects, risk, financial cost of projects, and overall net/benefit to Utah ratepayers. Division witness Mr. Matt Croft will address some of the O&M expenses, and Division witness Mr. Charles Peterson will discuss the financial and cost aspects of the projects. The Division's witness, Dr. Artie Powell, and our consultant, Mr. George Evans, will discuss wind integration costs, and I will report further concerns and recommendations of the Division.

[2] Direct Testimony of A. Robert Lasich, Docket No. 09-035-23.

Q. What kind of standard did you use to determine if the projects were in fact prudent choices for the Company to pursue and if the project costs were prudent investments on the part of the Company?

A. The Division believes the Company must abide by "the reasonableness standard," or what one would also consider prudent industry practices. Prudent industry practices include those practices, methods, standards and acts (including those engaged in or approved by a significant portion of the power industry for similar facilities in the United States) that, at a particular time, in the exercise of good judgment, would have been expected to accomplish the desired result in a manner consistent with applicable laws, safety, environmental protection, economy, and expedition.[3]

Q. Then would a decision by the Company to pursue a wind farm that might have less then desirable characteristics (such as a low capacity factor) be deemed imprudent?

A. The answer is that "it depends." Prudent industry practices are not necessarily defined as the optimal standard practice method or act to the exclusion of others, but rather refer to a range of actions reasonable under the circumstances. Utah Code Section 54-4-4(4)(a), below, provides guidance on the prudence standard:

> (4) (a) If, in the commission's determination of just, reasonable, or sufficient rates, the commission considers the prudence of an action taken by a public utility or an expense incurred by a public utility, the commission shall apply the following standards in making its prudence determination:

[3] www.secinfo.com/dC3v.7d.d.htm and also see www.puc.nevada.gov, Rule R142-09, Section 8, and see Long Island Power Authority Power Supply Agreement, p. 6.

(i) ensure just and reasonable rates for the retail ratepayers of the public utility in this state;

(ii) focus on the reasonableness of the expense resulting from the action of the public utility judged as of the time the action was taken;

(iii) determine whether a reasonable utility, knowing what the utility knew or reasonably should have known at the time of the action, would reasonably have incurred all or some portion of the expense, in taking the same or some other prudent action; and

(iv) apply other factors determined by the commission to be relevant, consistent with the standards specified in this section.

Q. Will you please discuss the project need aspect of this case?

A. Mr. Lasich identifies the project need for the McFadden Ridge I project in this case as being determined by the Company's Integrated Resource Plan (IRP).[4] The IRP uses load growth and resource need as a strategic planning tool that determines, on a long-term basis, an adequate and reliable electric supply at the lowest reasonable cost and in a manner consistent with the public interest. The IRP is supposed to determine the least cost/least risk resource plan under a reasonably wide set of potential future conditions. The result is a preferred portfolio that serves as a roadmap for the Company as to what resources need to be acquired, in what time frame, and which resource mix serves as the preferred portfolio. Mr. Lasich provides an almost identical explanation for the need for the Company's prior ten wind projects in his testimonies filed in Docket No. 07-035-93 and in Docket No. 08-035-35, respectively.[5]

[4] Direct Testimony of A. Robert Lasich, Docket No. 09-035-23, p 9, lines 205-206.
[5] Prefiled Direct Testimony of A. Robert Lasich, Docket No. 07-035-93 and Direct Testimony of A. Robert Lasich, June 2009, Docket No. 08-035-38.

His second justification for the need of the McFadden Ridge I project is the merger transaction commitments that MidAmerican Energy Holding Company (MEHC) made to acquire 1,400 MW of cost-effective, new renewable generation resources. Finally, Mr. Lasich states that the decision making process to acquire McFadden Ridge was prudent because the Company went through a methodical process of first determining the project need (as established by the IRP), then making a financial assessment of the project, followed by a consideration of the risks, and finally the overall justification for the project. According to Mr. Lasich, the benefits to Utah ratepayers are the following: the renewable resource will provide a zero incremental cost fuel source, will reduce the impact of individual generator failures, and provide the Company with valuable ownership and experience with utility scale wind projects.[6]

Q. Do you foresee any problem with this reasoning?

A. The Division generally supports the Company in pursuing renewable resources and trying to achieve its merger transaction commitments. The Company considered the relevant factors in its justification for the McFadden project, which the Division reviewed and found that the decision making process was prudent. However, the Utah Commission acknowledged neither the Company's 2007 IRP nor the Action Plan that are used in the analysis of need for this project. Disregarding that fact, the IRP is an analytical tool that determines the load and resource balance and the need and timing of the capacity

[6] Direct Testimony of A. Robert Lasich, June 2009, pp. 8-9.

additions needed in the system. With the volatility of fuel prices, the McFadden Wind project would have less risk, cost less, and is consistent with the results of the preferred portfolio. This said, the IRP does not consider specific projects, project locations, or resource characteristics. While the IRP reasonably suggests building wind resources, that alone does not mean that any single project is prudent. The Division believes that Mr. Lasich has demonstrated a need for wind projects, with the caveat that the Division cannot fully rely on the IRP analysis and results when the Commission has not acknowledged the IRP.

Q. How did the Company make the decision to move forward with the McFadden Ridge I wind project (and other projects as well)?

A. The Company used a similar approach for most of the wind projects that were filed as part of the test year for this case as it did for both of the two prior general rate cases referenced above. There were a total of ten wind projects that went into rate base in the 2007 and 2008 rate cases—Leaning Juniper I, Marengo I, Marengo II, Goodnoe Hills, Glenrock, and Seven Mile Hill projects in Docket No. 07-035-93[7] and Glenrock III, Rolling Hills, Seven Mile Hill II, and High Plains in Docket No. 08-035-38.[8] In the current docket Mr. Lasich is asking for a prudency finding for McFadden Ridge I. The Company uses the same approach in this case as was used in the past two rate cases, as described below:

[7] Prefiled Direct Testimony of A. Robert Lasich, Docket No. 07-035-93.
[8] Direct Testimony of A. Robert Lasich, Docket No. 08-035-38.

> Upon undertaking a thorough analysis which included (i) reviewing a detailed overview of the project including the contract support and counterparty guarantees, (ii) consideration of the risks, (iii) consideration of the need as established by the IRP, (iv) financial assessments, and (v) consideration of the justification for the project, Company executives made the decision that it would be in the best interests of our customers to proceed with the acquisition of this resource. The Company followed this process in determining that the resource, discussed in more detail below, is prudent and in the public interest.[9]

Q. Did the Division review the Company's process as described above?

A, Yes. When we looked at the wind projects identified above, there were times when we questioned the site location choice, the wind capacity factors, the purchase and choice of wind turbine generators, the sufficiency of wind data from the meteorological towers, and many other factors. However, the Division followed the Commission's guidelines suggesting that the Company's decision to pursue the project did not have to be the optimal choice, but rather reasonable and consistent with prudent industry standards at the time the Company had the information that was available.

Q. Did the Company acquire any of its wind projects through a Commission approved Request for Proposal (RFP) process?

A. None of the wind projects in the current case or the 2008 general rate case were required to go through the major resource acquisition competitive bidding process as each was less than 100 MW. However, the Company did acquire the Three Buttes Power Purchase Agreement through a Company RFP process termed "2008R."[10] Therefore, for the

[9] Direct Testimony of A. Robert Lasich, Docket No. 09-035-23, p. 9, lines 203-210.
[10] The Company also obtained the Mountain Wind I, Mountain Wind II, and Spanish Fork wind resources through PPA arrangements.

remaining ten wind projects, we do not know if the competitive market would have produced lower cost resources, and there was no Commission-appointed Independent Evaluator to advise the Commission on the fairness of the process.

Q. In light of the above, what other aspects of the wind projects did the Division investigate?

A. As components of the wind projects themselves, the Division also examined the purchase of wind turbine generators and the balance of plant (BOP) construction agreements for prudent decision making. The Division found that the Company did review several bids for the construction costs for the BOP portion of the wind projects. First, the engineer, procure, construct services (EPC), and collector substation transformer for the Seven Mile Hill II, Glenrock III, and Rolling Hills projects resulted from a PacifiCorp RFP issued by the Company's procurement department, with the winning bid going to Tetra Tech. The High Plains and McFadden Ridge I BOP construction projects were contracted with RES America, as both projects are interspersed on the same site.

Second, the wind turbine generators utilized at the Rolling Hills, Seven Mile Hill II, Glenrock III, and McFadden Ridge I sites were acquired based on the results of comparative bids that were submitted to the Company's procurement department for review.[11] For neither the BOP contracts nor the turbine purchases did the Company

[11] Response to DPU Data Request #7.3, August 12, 2009.

provide actual proposals from bidders (even though the Division requested them).[12] The Division reviewed the scoring sheets that were made available to us, and the Company appears to have acted reasonably and followed industry standards. However, without having been provided the actual proposals with which to judge whether the Company's scoring was itself reasonable, this remains a provisional conclusion.

Q. Please identify the disconcerting issues that the Division discovered in its analysis?

A. In the remaining portion of testimony, I will address those issues in the following order:

1. The Company's apparent strategy of building 99 MW wind farms adjacent to each other (or other, smaller projects,) as separate projects in order to avoid the solicitation process previously required in Utah and now required in Oregon for major resource additions.
2. The uniformity of wind characteristics in the Company's portfolio.
3. Optimizing wind turbine generators for each specific site.
4. Variances in BOP contracts and final project costs.
5. Other recommendations to the Commission with respect to what needs to be investigated in order to make a prudence determination for future wind projects.

Q. How has the Company pursued its acquisition of wind projects thus far?

[12] DPU Data Request # 4.6, Data Request #23.20, Data Request #23.21, Data Request #23.22 and Data Request #53.2.

A. In his Direct Testimony, Mr. Lasich describes the Company's strategy from the 2007 IRP procurement plan as follows:[13]

> *"In order to fill this requirement, the company will continue to aggressively pursue the acquisition of these resources through various approaches including new request for proposals, bi-lateral negotiations, the Public Utilities Regulatory Policy Act, and self-development." (2007 IRP at p. 229).*

Mr. Lasich also notes that all avenues of acquisition have been used, and he cites specific examples in his testimony.[14] In the 2007 General Rate Case, Mr. Lasich asked for a favorable prudency acknowledgment and that costs be placed into rate base for the Leaning Juniper I, Marengo I, Marengo II, Goodnoe Hills, Glenrock, and Seven Mile Hill II projects.[15] In the 2008 General Rate Case, Mr. Lasich asked for a favorable prudency finding for the costs of Glenrock III, Rolling Hills, Seven Mile Hill II, and High Plains.[16] In the current docket he is asking for a prudency finding for McFadden Ridge I.

Q. What concern does the Division have with the procurement strategy?

A. PacifiCorp's strategy of building wind plants has thus far been one of avoiding the previous Utah and current Oregon competitive bidding requirements under the guidelines for obtaining a major resource acquisition by building 99 MW projects adjacent to one another. In addition to the Glenrock/Rolling Hills projects identified above, the High Plains (99 MW) and McFadden Ridge I wind projects are also adjacent projects on the same or nearby site. However, in an Oregon Docket (UE 200), the Company states in a

[13] Id at p. 5, lines 94-100; (originally cited in the Company's 2007 IRP at p. 229).
[14] The Division notes that in 2008 the Company also obtained the Mountain Wind I, Mountain Wind II, and Spanish Fork II wind resources via Power Purchase Agreements.
[15] Prefiled Direct Testimony of A. Robert Lasich, Docket No. 07-035-93.
[16] Direct Testimony of A. Robert Lasich, June 2009, Docket No. 08-035-38.

data request that it "does not agree that any 99 MW wind project was sized merely to avoid the competitive bidding process.[17]

Utah Senate Bill 202, which became effective on March 18, 2008, established the revised current framework for the utility to procure new major resources. The guidelines require the Company to first issue an RFP and then, through the oversight of an independent evaluator, review the proposals that are received. The result of that process is that the terms and conditions of competitive bids provide a basis to compare resources and select the most economical choice such that ratepayers get the lowest cost resources available and pay only rates that have been deemed just and reasonable.

However, Section of the Utah Code 54-17-203 provides an exemption from many of Utah's competitive bidding requirements for renewable resources up to 300 MW under certain criteria, thereby increasing the procurement limit of 100 MW originally set in Senate Bill 26 in 2004. Oregon's rules currently require competitive bidding for all projects 100 MW or larger. It therefore appears to be more than coincidental that four 99 MW plants were built, rather than larger capacity plants on the same or adjacent sites. The table below groups the projects together by in service dates, lists the megawatt capacity, and identifies the location of each project. The grouping of projects by shaded area signifies those projects that are either adjacent to one another or that are actually interspersed. That these grouped projects have the same or similar in-service dates

[17] In the Matter of PacifiCorp 2009 Renewable Energy Adjustment Clause, Docket No. UE200. ICNU/102 Falkenberg/45.

suggests that they either are, *de facto*, single projects, or that they should have been built and planned as single projects.

Project	In Service Date	Location	MW
Glenrock I	December 31, 2008	Converse County, WY	99
Seven Mile Hill I	December 31, 2008	Carbon County, WY	99
Seven Mile Hill II	December 31, 2008	Carbon County, WY	18.5
Glenrock III	January 17, 2009	Converse County, WY	39
Rolling Hills	January 17, 2009	Adjacent to GR	99
High Plains	September 13, 2009	Albany and Carbon County, WY	99
McFadden Ridge I	October 31, 2009	Same as High Plains	28.5

Although technically the Company has not violated Utah guidelines in building adjacent 99 MW projects, without the benefit of the competitive market information that would have been provided by the bidding process, we cannot know if a more economical resource choice could have been made. The Division believes the Commission should require that the Company demonstrate that adjacent projects built within a year or two of one another have achieved optimal cost efficiencies and have not incurred extra costs by

being split into two or more separate construction phases or reclassified as separate projects.

Q. What do you mean when by your previously terminology "an apparent strategy to build 99 MW wind farms?"

A. While the Company distinguishes the Rolling Hills and Glenrock projects as separate resources, they are both on the same site, both are 99 MW capacity plants, and both have the same in-service year. The Company did not acquire the Rolling Hills project through the competitive bidding process or request a waiver for the project. In a recent case in Oregon, the Oregon Utility Commission addressed this same issue, but did not rule on whether the Rolling Hills and Glenrock projects should be treated as a single project.[18] However, the Commission did rule that Pacific Power failed to demonstrate that it prudently acquired the Rolling Hills project.

Q. Do we know if Utah ratepayers would have been better off if the smaller projects had been combined into one?

A. No. However, we do know that the Company has tried to take advantage of some economies of scale with the recently built adjacent wind projects. For example, with the Seven Mile Hill II project the Company was able to interconnect to the Freezout substation, which was previously constructed for first Seven Mile Hill project.[19] The Company was also able to avoid building several roads and operations and maintenance

[18] Oregon Public Utility Commission, Order No. 08-548.
[19] Company's Response to DPU Data Request 23.2, September 10, 2009.

centers, as these were previously built for other uses. For the Glenrock project, the Company benefited from cost savings for the project, as the transmission line running to the Windstar substation, the collector substation, the roads, and the operations and maintenance buildings were previously built. With respect to McFadden Ridge I, the transmission line running to the Foote Creek substation and from Foot Creek to Miners, as well as roads, operations and maintenance building, have all previously been built. In each of the instances above, the Company may have realized economies of scale, and thus cost savings to ratepayers, on projects that had transmission and other early construction work completed from prior projects.

Q. What were the alternative wind site locations that the Company looked at in making its procurement decisions?

A. The Division asked the Company if it had considered alternative wind sites, but the Company responded that the alternative would be an alternate energy source, not an alternative or specific wind site.[20] For example, when the Company discovered that the wind capacity factor at Rolling Hills was only [redacted] percent, the Company's apparent analysis did not examine whether the Rolling Hills wind turbines should be placed at another site, but rather whether the project should be abandoned in favor of market purchases. In his direct testimony, Mr. Lasich addresses the alternative to the McFadden Ridge I wind project considered by the Company:

[20] DPU Data Request #34.12

> Utah customers benefit from the McFadden Ridge I resource because it represents a better-long-term, cost/risk balance for the Company to generate electricity with this resource than to make purchases in the open market.[21]

Q. Will you please describe the Division's concerns with respect to the operational characteristics of diverse types of wind?

A. Yes. Mr. Lasich, in all three years of his testimony — 2007, 2008, and the current rate case — emphasizes that Utah customers benefit from each year's proposed wind plants because they provide us with "multi-shafted generation resources (thus diversifying the impact of individual generator failures). . ."[22] While the Division agrees that a diverse portfolio mix of generating units is desirable, what Mr. Lasich fails to mention is the importance of the Company also diversifying its wind portfolio. The Division believes that incorporating large amounts of wind into the generation mix means that the wind portfolio itself needs to be diverse. Recently, the Company has predominantly pursued Wyoming wind resources with somewhat similar operating characteristics.

Q. As long as there are sufficient renewable resources being procured, why is the Division concerned about the characteristics of PacifiCorp's wind portfolio?

A. Our concerns focus on both the reliability of wind resources and the associated integration costs when those resources have similar or uniform operational characteristics. The Company indicates in its IRP that it intends to continue to acquire 200 MW of wind per year over the next ten years or beyond. The Division believes that,

[21] Direct Testimony of A. Robert Lasich, June 2009, p. 8, lines 182-184.
[22] Id at p. 191-192. Also see Docket No. 07-035-93, p. 16, lines 357-360, December 17, 2007 and Docket No. 08-035-38, pp. 7-8, lines 148-152, July 17, 2008.

with thousands of megawatts of wind being placed into service to help fill the Company's capacity deficit, we should be concerned about the total wind capacity available at any given hour. The recently built Wyoming resources tend to have wind resources that are strongest in winter and frequently at night. Many are also very close to one another. The Division believes that the Company needs to acquire a diverse mix of wind resources, including wind that is diurnal, some that blows in the winter, some that blows in the summer, some that peaks in afternoon hours and during different years and seasons — overall, wind that has more variation in its characteristics. Geographic diversity is also important in order to decrease the probability that all of its wind resources will be unavailable at the same time. The current resource mix also does not contribute as much as it might to meeting summer peak demand, thus avoiding the need for expense market purchases or combustion turbine operation.

The Division asked the Company in DPU Data Request #23.28 if it had looked at projects that had some different operational characteristics from the current projects. The Company responded as follows:

> The Company makes the decision to acquire each renewable resource on a case by case basis, based on characteristics specific to that individual resource and if acquisition of the resource is expected to benefit customers. These resource specific analyses take into account expected seasonal production and, as such, inherently account for the expected net financial benefit to customers as a result of seasonal production levels. By doing so, it is not necessary for the Company to limit its consideration to resources that produce more energy during certain time periods (i.e., summer months) since the Company evaluates the overall economic viability of the resource.[23]

[23] Response to DPU Data Request 23.38, September 10, 2009.

The Division believes this is an unacceptable response and expects the Company to diversify its wind portfolio in the future. Not only is this a reliability concern, but the lack of diversity in the operating characteristics may lead to unnecessarily high integration costs for wind generation. In the Company's wind integration cost model, the similar operating characteristics of wind resources amplify the need for incremental reserves, thus, increasing the integration costs for all wind generation. As discussed in the testimony of the Division's consultant, Mr. Evans, the Company's wind integration costs assume the carrying of a [redacted] reserve factor, which seems to carry the assumption that many of its wind resources will be unavailable at the same time. Such high reserves are not reasonable and, if they are made necessary by the homogeneity of wind resources in the Company's portfolio, amplify the Division's concern on the need to diversify wind resources and locations.

Q. Has the Company evaluated wind integration costs and the capacity planning that must be addressed as large quantities if wind resources are added to the system?

A. In Appendix F of PacifiCorp's 2008 IRP, the Company discusses the impact of maintaining system reliability when large quantities of wind are integrated on PacifiCorp's system. PacifiCorp's integration costs involve statistical variability of wind and the costs of balancing this amount in the day and hour ahead, and the incremental reserve costs to do so. If all the wind is blowing at the same time – or more importantly NOT blowing at the same time, the wind integration costs are going to be higher than if the wind being added to the system had a diverse set of operating characteristics. The

Company states in Appendix F that it is actively investigating and exploring potential tools and approaches to address the consequences of adding large increments of wind resources to its system, and the Division believes that wind diversity needs to be one of the considerations.

Q. Are certain types of wind generator turbines more suitable for some projects than others? If so, please explain.

A. Yes. The Division determined that certain types of wind turbine generators models adapt better to certain conditions than other turbines and thus can optimize costs per megawatt hour of projected output. There are currently two 1.5 MW GE models available, as well as other wind turbine manufacturers, such as Clipper Liberty, Vestas, Gamesa, Mitsubishi, and Repower (to name a few). The rated wind speed[24] for the GE 1.5sle model is higher than the newer GE 1.5xle (14 versus 11.5 meters per second, or m/s).[25] The cut-out speed for the GE 1.5sle model is 25 m/s, whereas for the GE 1.5xle, the cut-out speed is 20 m/s.[26] What this means is that the GE 1.5sle model can handle stronger wind conditions (such as the Wyoming wind) than the GE1.5xle. The GE 1.5xle is more suitable for slower wind types due to its longer blade length.[27] It should be pointed out, however, the 1.5xle model was not available to the Company at the time its turbines for the five projects we have examined were purchased. Other GE 1.5 models were,

[24] The rated speed is the minimum speed at which the wind turbine will generate its designated rated power. See www.energybible.com/wind.
[25] www.ge-energy.com/wind.
[26] Id. At very high wind speeds, most wind turbines cease power generation and shut down. The wind speed at which shut down occurs is called the cut-out speed. See www.energybible.com/wind_energy/wind_speed.html.
[27] Id.

however, available that were designed to operate in higher-speed wind regimes at lower cost.[28]

The Division reviewed data responses to determine that the Company made several large purchases of the same GE 1.5sle wind turbine generators, realizing there are other models and makes of turbines that have their own site suitability based on terrain, wind conditions, wake loss, wind shear, and a myriad of other technical specifications. For instance, the Company used the same turbines for the Seven Mile Hill and Rolling Hills projects. Seven Mile Hill's average wind speed, as determined in CH2M Hill, is [redacted] whereas Rolling Hills' wind speed is [redacted], suggesting that different turbine models should have at least been considered for these two projects. Through data requests, the Division asked the Company about whether different GE 1.5 models were considered, and also asked the Company why they happened to use the same number of GE 1.5sle turbines (66) for at least four different sites in the following DPU Confidential Data Request #23.18:

[28] Turbines designed for higher winds are able to continue operating in higher winds than others due to shorter blade lengths. Smaller blades make such models impractical for low-wind sites, but their lower cost can result in more-economic projects.

The Company responded as follows:

The Company also indicated that, due to the combination of the wind turbine availability and a reasonable expectation that purchased turbines could be incorporated into a wind project prior to the expiration of the federal production tax credit, it made the decision to purchase turbines on a sole source contract. Two notification letters were filed with the Commission on June 8, 2007, and on August 1, 2007, respectively. The letters explain and justify the factors that led the Company to make the purchases at the time, as well as the terms of the sole source contracts.

Q. Can you spell out the Division's concerns on these points?

A. The Division has concerns regarding using wind turbine generators that are not optimized for each specific site. For the wind turbine generators used at the Rolling Hills site,

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] The Rolling Hills site had a relatively low wind capacity factor as compared to average Wyoming wind sites that had a net capacity factor of about 35 percent. The Division cannot determine whether another site or other turbines would have provided a greater benefit to customers. However, we do know that the specific wind turbine generator selected and other manufacturer design changes may impact the efficiency the project.

In another example, [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted] here may have been other turbines that would have been more suitable for the site had all options been considered. The Division acknowledges that the turbine supply market was tight at the time and has eased somewhat since, but encourages the Company to optimize the turbine selection for each site in the future.

[29] Company's Confidential Data Response to DPU Data Request #23.3-2.
[30] Company's Confidential Data Response to DPU Data Request #50 and McFadden Ridge I Recommendation Memo, April 17, 2009, p. 2.

The Division believes that the Company has sufficient experience in developing utility wind scale projects, that it should optimize the choice of turbines for each specific project going forward and diversify its selection of turbine models to be able to use a wider variety of sites and resources.

Q. You previously stated that secondary to the wind turbine generator costs, the balance of plant construction was one of the major project costs for wind resource additions. What are the Division's concerns in this regard?

A. The Division, in its discovery process, has noted large variances in the BOP contract costs versus what has been reported in final project costs. The first instance in which the BOP costs appear are in the Company's appropriation request forms that accompany the wind approval documents for each respective project. The Division next reviewed the contract terms between the Company and [redacted], the contractors selected for the wind projects examined. These costs are listed in the table that follows. Finally, there is yet another BOP cost that the Division obtained through DPU Confidential Data Request# 23.10-1, all of which are listed in the table below. The Company needs to explain why the BOP costs would vary this much, especially when the costs are signed and documented in a BOP contract. As illustrated in the table below, Rolling Hills and Glenrock III had a variance of millions of dollars in the amount reported in DPU #23.10-1 compared to what was listed in the BOP contract. These costs differences have not been accounted for as of the date of this filing. The Division is awaiting discovery on this issue (as well as BOP costs for High Plains) and thus we

reserve the right to make an adjustment after we have reviewed the Company's data responses on this issue.

	BOP in APR	BOP in contract	BOP in DR #23.10-1	Difference
McFadden	$11,001,000	$10,250,000	$10,277,555	$751,000
High Plains	$53,683,000			
Seven Mile II	$9,808,755	$9,755,750	$9,808,755	$53,005
Rolling Hills	$50,970,000	$44,982,976	$55,579,423	$4,609,423
Glenrock III	$29,803,699	$18,677,300	$29,803,699	$11,126,399

Q. What can you conclude about the prudency of the Company's decisions in acquiring wind resources?

A. Inasmuch as the Company has an aggressive strategy to acquire 200 MW of wind each year for the next 10 to 20 years, the Division believes we need to take a close look to make sure that all of the decisions are prudent, the costs are justified, and there is a net benefit to Utah ratepayers on future wind acquisitions. The Division intends to conduct a prudency review of all future wind projects that the Company proposes bringing into rate base. In order to so, we make the following recommendations to the Commission:

- The Company should consider looking at diverse wind characteristics going forward in the acquisition of its wind portfolio.
- The Company should be required to submit a notification letter to the Commission at the time that each wind plant comes in service.
- The Commission should review the Company's strategy of building 99 MW wind farms adjacent to each other as separate projects in order to avoid the solicitation process required in Oregon for major resource additions.

- The Company needs to report detailed accounting of its capital wind projects rather than lump sum capital costs in order for the Division to complete a full prudence review of future wind projects.

V. THE DIVISION'S FINDINGS AND RECOMMENDATIONS

Q. Will you please summarize the Division's findings and recommendations?

A. Based on the reasons discussed above, the Division proposes [redacted] contingency adjustment on the McFadden Ridge I wind project and a disallowance of contingency costs on all future wind projects. The Division finds that the McFadden project is a prudent investment and will benefit Utah ratepayers by providing a zero incremental cost fuel source, as well as a demonstrated source of needed renewable energy. Finally, the Division recommends that the Commission continue to evaluate the prudency of wind plants expected to come in service in future years with the information needs and concerns as identified above.

Q. Does this complete your testimony?

A. Yes it does.