- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp for Approval of an IRP-Based Avoided Cost Methodology For QF Projects Larger Than One Megawatt	))))	DOCKET NO. 03-035-14 REPORT AND ORDER

ISSUED: October 31, 2005

SHORT TITLE

PacifiCorp Large QF Avoided Cost Case

SYNOPSIS

The Commission approves an avoided cost method for pricing contracts for power purchases from Qualifying Facility projects larger than one megawatt for cogeneration facilities and three megawatts for small power production facilities.

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I. PROCEDURAL HISTORY

On October 7, 2002, PacifiCorp filed a proposed tariff Electric Service Schedule No. 38, Qualifying Facility ("QF") Procedures (Docket No. 02-035-T11). Schedule No. 38 establishes procedures for purchases of power by PacifiCorp ("Company") from QFs larger than the limit in Electric Service Schedule No. 37 (one megawatt for cogeneration facilities and three megawatts for small power production facilities). Schedule No. 38 lists the information that is required of a QF in order to get indicative pricing and sets a time frame for the Company to provide it. The introduction of this schedule addresses an impediment to non-utility generation identified in an informal investigation undertaken by the Commission at the request of the Utah Legislative Energy Policy Task Force. On November 12, 2002 the Commission suspended the Schedule No. 38 filing to allow time for comments by parties and asked the Company to respond. A QF work group including the Company, the Division of Public Utilities ("Division"), the Committee of Consumer Services ("Committee") and other interested parties was convened, followed by the Company filing a revised Schedule No. 38 on December 13, 2002. On February 24, 2003, the Commission approved the revised Schedule No. 38, and required the Company to continue the QF work group and file within 90 days an avoided cost method and a generic power purchase agreement for large QFs.

On May 27, 2003, the Company filed an application for approval of an Integrated Resource Plan ("IRP")-based avoided cost method for pricing utility purchases from QF projects larger than the cap in Schedule No. 37. In response to recommendations from the Division and the Committee, on September 24, 2003, the Commission ordered the Company to reconvene the QF work group to address unresolved capacity payment issues and to file a revised avoided cost method for large QFs within 60 days. This filing deadline was subsequently extended to February 3, 2004 to allow the QF work group more time to discuss unresolved issues.

On February 3, 2004, the Company filed direct testimony to support its request for a new generic avoided cost method for pricing QF contracts under Schedule No. 38. On March 24, 2004, the Commission issued an order establishing a procedural schedule which was subsequently revised. Parties other than the Company filed direct testimony on April 9 and 12, 2004. All parties filed rebuttal testimony on May 7, 2004, and surrebuttal testimony on May 11-13, 2004. At a May 20, 2004 hearing, parties presented a stipulation which the Commission approved in a June 28, 2004 order. Based on avoided cost, the stipulation establishes indicative capacity and energy prices for a QF project whose design capacity exceeds the limits in Schedule No. 37. The stipulation covers an interim period, which ends when the Commission issues an order adopting new avoided cost terms and/or prices for QF projects whose capacity exceeds the Schedule No. 37 limits. The stipulation's prices should be available to any QF contract approved during the interim period so long as power from the QF project is available to the Company no later than June 1, 2007, up to a cumulative cap of 275 megawatts for all QF contracts approved during the interim period. Four QF contracts based on the stipulation were approved later in 2004, accounting for approximately 175 megawatts of the 275 megawatts available under the stipulation's cap. The stipulation also establishes a task force to further study long-term generic pricing methods based on avoided cost, renewable QF issues, the impact of accounting and other debt-related issues, and green tags (renewable energy credits) related to QFs. It was anticipated the task force would complete its work by the end of 2004.

On February 11, 2005, the Commission issued a Notice of Scheduling Conference to be held on February 18, 2005, since it appeared unlikely the task force would be able to reach a consensus resolution on the issues before it in a timely manner. The absence of a consensus resolution from the task force on how larger QFs, who have no contract with the Company, should be treated was the genesis of Spring Canyon's request in Docket No. 05-035-08 and Pioneer Ridge/Mountain Wind's request in Docket No. 05-035-09, both seeking QF contracts. An order was issued on February 24, 2005 adopting a schedule, including a hearing on March 24, 2005 to resolve issues regarding the interpretation of the stipulation as it applied to the requests of Spring Canyon and Pioneer Ridge/Mountain Wind. On April 1, 2005, the Commission issued an order resolving these issues, and in addition, set a date for a conference to schedule further proceedings in the current docket intended to establish final methods of establishing QF prices based on avoided costs.

On May 2, 2005 the Company filed direct testimony in accordance with the previously established schedule. In response to a request for reconsideration by the Committee, on May 18, 2005 the Commission issued an Order of Clarification. On July 1, 2005, an Amended Scheduling Order was issued at the request and agreement of parties. On July 29, 2005, the Division, Committee and intervenors filed direct testimony. A technical conference was held on August 15, 2005 followed by a settlement conference on August 30, 2005. Parties filed rebuttal testimony on September 8, 2005. The Company filed supplemental rebuttal testimony on September 12, 2005. Parties filed surrebuttal testimony on September 19, 2005. Hearings were held on September 22, 23, 26 and 27, 2005 at which time testimony and evidence were received and witnesses cross-examined. Spring Canyon filed direct testimony, but did not participate in the hearings.

Parties to this case are: the Company, Division, Committee, UAE Intervention Group ("UAE"), US Magnesium LLC ("US Mag"), Mountain Wind LLC, Pioneer Ridge LLC ("Pioneer"), Wasatch Wind LLC ("Wasatch Wind"), Spring Canyon Energy LLC ("Spring Canyon"), Western Resource Advocates, Utah Clean Energy, Exxon Mobil, Desert Power, United States Executive Agencies, Utah Energy Office and Mountain West Consulting LLC ("Mountain West").

II. DISCUSSION, FINDINGS AND CONCLUSIONS

A. INTRODUCTION

Section 210 of the Public Utility Regulatory Policies Act (PURPA) of 1978 specifies the obligation of the Company to purchase capacity and energy made available from a QF, and to make such purchases at no more than avoided cost. Avoided costs are defined as the incremental costs to the Company of electric energy and/or capacity, but for the purchase from the QF the Company would generate itself or purchase from another source. Section 210 also specifies the obligation of the Company to make necessary interconnections with a QF, the costs of which, as approved by this Commission, are to be paid by the QF.

A QF is defined to be a qualifying cogeneration facility or a qualifying small power production facility within the meaning of section 201 and 210 of the PURPA, 16 U.S.C. 796 and 824a-3. A cogeneration facility means a facility which produces electric energy, and steam or other forms of useful energy, such as heat, which are used for industrial, commercial, heating, or cooling purposes. A qualifying cogeneration facility means a cogeneration facility which meets certain requirements that may be prescribed by the Federal Energy Regulatory Commission

(“FERC”), including minimum size, fuel use, fuel efficiency and ownership.

A small power production facility means a facility which is a solar, wind, waste, or geothermal facility, or a facility which produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, and has a power production capacity which, together with any other facilities located at the same site is not greater than 80 megawatts. A qualifying small power production facility means a small power production facility which meets certain requirements that may be prescribed by the FERC, including fuel use, fuel efficiency, reliability and ownership.

Schedule No. 37 is available to owners of QFs in all territory served by the Company in Utah and provides prices for power purchased from QFs whose design capacity does not exceed 1 MW for a cogeneration facility or 3 MW for a small power production facility. Schedule No. 37 was most recently addressed in Docket No. 03-035-T10. Schedule No. 38 establishes the process for negotiating power purchase and interconnection agreements between the Company and QFs larger than the limits set forth in Schedule No. 37. Other requirements may apply to Utah QFs seeking to make sales to third-parties, or out-of-system QFs seeking to wheel power to Utah for sale to the Company.

In order to calculate the avoided costs associated with a purchase from a QF, an approach widely used by utilities since the passage of PURPA in 1979 is termed the Differential Revenue Requirement (“DRR”) method. This method is based on two forecast scenarios over the Company’s planning horizon, and involves a comparison of the net present value of future revenue requirement for two resource portfolios. The first portfolio reflects the future resource decisions the Company would make in the absence of purchases from the QF. The second portfolio reflects the future resource decisions the Company would make if power from the QF were available to the Company at no cost. The resources selected in each portfolio are based upon a consideration of cost, risk and other characteristics. To determine an optimal resource portfolio, with and without the QF, a capacity expansion planning model and a production cost model are employed to simulate the acquisition and use of resources in the operation of the utility system. The net present value of revenue requirement is calculated reflecting the total of capital and energy costs over the planning horizon associated with each resource portfolio. In the DRR method, the avoided costs of a purchase from a QF are the differences in the net present value of revenue requirements for the two optimal resource portfolios, with and without the QF.

The Company has recently completed and filed with the Commission its IRP 2004 which identifies its optimal selection of future resources over a twenty year planning horizon, termed its Preferred Portfolio. The IRP selection process involves evaluating many different alternative resource portfolios, including stochastic and scenario analyses of the portfolios under a variety of assumptions, including electric and gas price forecasts, as well as environmental costs. Currently the Company uses a manual portfolio building process rather than a computer-based capacity expansion model. The Company testifies, therefore, it is not practical each time it receives an offer from a QF, to evaluate multiple portfolios through this IRP process in order to determine a new optimal resource portfolio, and therefore changes in capital requirements, based on a zero-cost QF resource, a key step in the DRR method. The Company, the Division and Committee support the use of a variant of the DRR method, which is a combination of a proxy method for avoided capacity costs and the Partial Displacement Differential Revenue Requirement ("PDDRR") method for avoided energy costs.

In this order, the Commission resolves differences among the parties regarding methods by which avoided capacity and energy costs are calculated and indicative prices are determined for the purpose of negotiating agreements pursuant to Schedule No. 38, and resolves other contractual issues as well. The intermittent characteristic of energy produced from wind facilities introduces issues unique to that type of QF. Therefore we first address issues regarding QFs excluding wind, then address issues regarding wind QFs. Accounting and contract issues are then addressed, followed by a brief discussion of whether Schedule No. 38 should go beyond adopting a method of determining prices and actually calculate and provide indicative prices in the schedule. Finally, the treatment of QF projects whose capacity is 100 MW or greater is addressed.

B. COGENERATION FACILITIES BETWEEN 1 AND 100 MEGAWATTS AND SMALL POWER PRODUCTION FACILITIES, EXCLUDING WIND, BETWEEN 3 AND 100 MEGAWATTS

1. Avoided Generation Capacity Cost Method

The Company, Division, Committee, US Mag and UAE propose the Proxy method for determining avoided generation capital cost. The Proxy method uses the capital cost of a proxy resource to calculate avoided generation capital cost per kilowatt. The proxy resource is identified as the next deferrable generating unit in the Company’s most recent IRP. In the Preferred Portfolio of IRP 2004, the deferrable resource is a combined-cycle combustion turbine (“CCCT”) facility, with duct firing, located at Mona, Utah, and scheduled for service in 2009. The capital cost per kilowatt is calculated using the operating characteristics and payment factor identified in the IRP for this resource, including its IRP reported non-fuel fixed and variable operation and maintenance costs. To convert the proxy plant capital cost, grossed up for revenue requirement, to an annual cost per kilowatt, the method uses the IRP resource payment factor as the basis for the real levelized annual cost of the present value of the investment and adds inflation in each year thereafter. The non-fuel variable operation and maintenance costs are converted into an annual cost per kilowatt, using the relevant reported capacity factors in Table C.28, "Supply Side Options - Resource Cost Sheet"of IRP 2004, adjusted for inflation, and this amount is added to the annual avoided capital cost calculation. This produces avoided capital costs that increase over time. No capacity payment is made in months in which the QF is unavailable for dispatch in high load hours.

UAE supports the Company's proposed Proxy method for determining generation capacity payments, described above, provided capacity payments are also available in years prior to the online date of the next deferrable IRP resource. We address the issue of the time over which capacity payments are to be made in the levelization section.

All parties support the Proxy method as proposed by the Company for calculating avoided generation capacity costs. We approve this method which is based on the next deferrable IRP resource for calculating avoided capacity costs to provide indicative capacity prices.

2. Avoided Energy Cost Method

The Company, Division and Committee propose the PDDRR method for determining avoided energy cost. UAE proposes the Proxy method for determining avoided energy cost.

To calculate avoided energy cost, the PDDRR method employs the Company's production cost model, GRID, to simulate the hourly operation of PacifiCorp's utility system. GRID is currently used by the Company to normalize its net power costs in rate proceedings. Net power costs include fuel costs and wholesale market sales and purchases. Two twenty-year GRID runs are performed to calculate hourly avoided energy cost. The first run is the existing utility system plus the planned resources contained in the Company's Preferred Portfolio in its most recent IRP; the second run is the same as the first run with two exceptions: the operating characteristics of the proposed qualifying facility are added with its energy dispatched at zero cost and the capacity of the IRP resource is reduced by an amount equal to the QF capacity. The difference in production cost between the two runs is the avoided energy cost. The indicative annual energy price, available as a fixed price over time in dollars per megawatt hour is determined by dividing the annual production cost difference by the annual proposed QF energy output. For unscheduled or non-firm energy deliveries, the method is the same with one exception: energy cost in the second GRID run is capped in each hour at the fuel cost of the deferrable IRP resource. A variable energy payment option is proposed for energy dispatched at PacifiCorp's request. It is calculated by multiplying the heat rate of the deferrable IRP resource by the cost of fuel associated with the deferrable resource, the cost of which is included in rates, multiplied by the amount of energy dispatched.

UAE's Proxy method uses a proxy resource to calculate avoided energy cost. UAE proposes alternative methods for calculating avoided energy cost depending on when the energy is delivered and whether a fixed or variable price option is requested by the QF developer. For fixed energy prices, avoided energy costs in the period prior to the 2009 online date of the Mona CCCT is defined as 93 percent of the Company's March 31, 2005 Palo Verde price forecast capped at the Mona CCCT energy cost. The Mona CCCT energy cost is calculated using the energy weighted heat rate of the CCCT including duct-fired capacity, using the capacity factors and heat rates reported in IRP 2004 Tables C.27 and C.28. For variable energy prices regardless of year, this same energy-weighted heat rate times a natural gas price index plus transportation is proposed for QF developers for energy dispatched at PacifiCorp's request.

For UAE's fixed pricing proposal, beginning in 2009, the heat rate of the CCCT portion of the plant is annually increased to reflect performance degradation. This heat rate is then used to calculate the energy weighted heat rate of the CCCT and duct-fired capacity. This increasing, weighted average heat rate is then multiplied by PacifiCorp's natural gas price forecast.

For non-firm energy or energy delivered at the discretion of the QF owner, UAE proposes a reasonable percentage of an electric index be used to calculate avoided cost. UAE proposes avoidable transmission losses also be added to the energy payment if the QF is located near the Wasatch Front load center such that losses can be avoided.

US Mag proposes a variable pricing option, often called a tolling arrangement, for energy dispatched by the Company. Payment to the QF for energy delivered in these hours would be equal to a heat rate times a natural gas price index. For energy delivered in other hours, US Mag proposes the price be equal to 93 percent of the Palo Verde electric price index. For a QF opting for a fixed price, US Mag supports use of the PDDRR method, providing certain artificial modeling constraints are removed, i.e., the cap on market transactions and lack of non-firm transmission. US Mag recommends the Proxy/PDDRR method be used to identify published prices associated with deferral of the entire IRP resource that potential QF developers could rely on until the amount of QF power under contract reaches the capacity of the next deferrable plant. These published prices can be rerun periodically as a new level of resource is under contract.

Witnesses stress the need for an avoided cost method that ensures ratepayer neutrality and at the same time encourages efficient and clean QF resource development. To accomplish both tasks, witnesses argue the method must be reasonably accurate yet also understandable and transparent.

The Company, Division and Committee recommend adoption of the PDDRR method, which uses the GRID production cost model to calculate avoided energy costs, because it is reasonably accurate, flexible, predictable, understandable, maintains ratepayer neutrality and handles as many situations as possible. These parties argue that, consistent with PURPA requirements, the PDDRR produces avoided costs that reflect the operating characteristics in a predictable way. The Committee demonstrates that PDDRR is flexible in modeling a variety of QF operating conditions, and that it provides intuitive results that vary with changing QF operating characteristics. The Committee also shows that the Proxy model proposed by UAE produces prices that are relatively insensitive to changes in QF operating characteristics. The Committee testifies that both UAE and US Mag admit that the QF must be like the IRP resource to get reasonable results from the proxy model and that when the QF operates outside the IRP resource characteristics another method should be used. US Mag notes that although the GRID model is difficult, it is quite impressive and does not oppose its use. UAE states that while it prefers the proxy model, it is not totally adverse to using the PDDRR. The Committee notes that UAE and Wasatch Wind witnesses both uncovered data errors in the model, that all parties agree must be corrected, demonstrating it is not a black box.

While the Division supports the GRID model because of its logical consistency, it identifies memory problems on the Company provided computers that must be fixed. The Committee testifies that no party argues the PDDRR method is unreasonable but rather parties fault it for being too complex. The Company and Committee argue that the complexity of a production cost model is necessary to accurately reflect the complexity of utility operations. For example, the PacifiCorp utility system includes use of coal, hydro, renewable resources and market opportunities to meet demand in addition to gas plants. The Committee testifies that production cost modeling is employed by regulatory bodies throughout the nation because it is the best way to simulate utility operations. The Division proposes training on the GRID model for a nominal fee to facilitate its ease of use among users. The Company stated it is working on providing internet access to the GRID model.

The Committee argues UAE's proxy method for avoided energy costs erroneously assumes either natural gas or market purchases will be on the margin in all hours when this is quite unlikely. When this assumption is modified to include coal output, the proxy method produces an avoided energy cost that is similar to the PDDRR method. In order to include a coal output weight in the proxy method, the Committee argues, one would need to know the appropriate level of coal output which brings the problem right back to an analysis of the Company's production costs and therefore the very circumstances the PDDRR method is designed to capture. The Company and Division provide evidence of actual operations, showing that coal resources are backed down in some low load hours, hence coal, not gas resources are on the margin. The Company testifies that the market cap assumption in GRID, an assumption limiting sales in some hours, in this case is consistent with the market cap assumption used in the GRID model in general rate cases. It is based on 48 months of market sales history. The Company additionally provides an exhibit that it states shows actual coal generation is even lower than simulated in GRID, demonstrating the reasonableness of the results associated with backing down coal resources.

Although it is not totally adverse to its use in calculating avoided energy costs, UAE testifies the GRID model is difficult to use and prefers the easier to use proxy method. US Mag testifies the proxy method for avoided energy costs is simpler and produces the same results as the PDDRR method when the QF has the same operating characteristics as the proxy model. Thus, for such conditions the proxy method should be adopted because it is simpler. UAE and US Mag dispute the number of hours coal is shown to be on the margin in low load hours in the GRID model, arguing that the market cap and non-firm transmission assumptions erroneously cause more coal output to be on the margin and this error reduces costs likely to be avoided by a QF supplying energy in low load hours. Upon cross examination, however, UAE and US Mag were unable to produce evidence to support the assertions that coal output could or should be higher than shown in GRID. Further, neither UAE nor US Mag witnesses offered testimony or evidence to demonstrate consistently liquid markets in low load hour or non-firm markets to allow Company resources to make sales in all hours. The avoided costs in low load hours account for the bulk of the difference in results in the two methods.

We are persuaded by the evidence that coal resources are backed down in some hours and use of a production cost model, including market caps, is necessary to accurately identify the production costs avoided by a QF and thereby maintain ratepayer neutrality. We therefore approve use of the PDDRR method for calculating avoided energy costs to provide indicative energy prices for a fixed price payment option for power dispatched by the Company. The variable pricing option is addressed in the tolling section. To facilitate ease of use, we direct the Company to fix the computer memory problems and provide reasonable GRID training to interested parties at no fee. We also direct the Company to continue its efforts to provide internet access to the GRID model.

3. Non-Firm Transmission

The Company and Committee exclude non-firm transmission opportunities from the GRID model. The Company testifies it cannot rely on non-firm transmission to make sales and any amount should be excluded from the analysis. UAE and US Mag propose non-firm transmission be included in GRID because such opportunities exist in utility system operations. The Division testifies that some non-firm transmission is used on a regular basis and supports inclusion of a reasonable amount of non-firm transmission in GRID but has no specific proposal for how to do this. The Committee has no objection to modeling non-firm transmission if it is legitimate but notes it has no evidence of a reasonable amount that is routinely available. In order to reflect utility operations as closely as possible, we order inclusion of non-firm transmission in the GRID model. A 48-month history of non-firm transmission, developed in a manner similar to that for market caps, shall be used as the basis for the non-firm transmission assumptions included in both the base and QF GRID runs.

4. Tolling for Dispatched Power

All parties propose a variable energy price, or “tolling” option be available at the request of QF developers. This option is for hours in which the QF is dispatched at the

Company's request. The variable energy price is calculated as a heat rate times the cost of fuel. However, the parties propose different heat rates and different fuel cost assumptions to calculate variable energy payments. UAE and US Mag propose the energy weighted heat rate of the next deferrable plant in the IRP, which includes the output of both a CCCT and duct-fired capacity, and is calculated using the capacity factors and heat rates reported in the equivalent of IRP 2004 Tables C.27 and C.28. They argue this is reasonable because it is consistent with the avoided capacity cost payment, which is based on the capacity weighted average of both the CCCT and duct-fired capacity. The Company, Division and Committee propose a heat rate equal to the CCCT portion of the plant. Upon cross examination, when it was implied that the Company, Division and Committee's choice of heat rate was end-driven, designed to reduce payments to QF's, the Division responded that this was not necessarily the case since payments are a function of the number of hours a QF is dispatched and a lower heat rate would cause the QF to be dispatched more often, possibly resulting in higher total payments.

It is our understanding that when the deferrable IRP resource is a combination plant, with both CCCT and duct-fired capability, the QF can displace the energy output of either of the plant components. For consistency with this expected displacement, we concur with use of the energy-weighted heat rate, as calculated in UAE's testimony and described in this order, when the IRP deferrable resource is a combination plant.

UAE and US Mag propose use of the Opal Natural Gas Price Index plus transportation because it is a transparent and easily verified price. The Company, Division and Committee argue use of the Opal index transfers gas price risk from the QF to the Company and its customers and propose use of natural gas costs included in the Company's Utah rates to mitigate this shift in risk. To maintain ratepayer neutrality, we approve the use of the Company's relevant fuel costs in rates as the index to use for the variable energy pricing option.

5. Non-Dispatch or Non-Firm Payments

For periods when the QF has the unilateral right to decide when PacifiCorp will purchase their power, the Company, Division and Committee propose using the PDDRR method capped at the fuel cost of the IRP deferrable resource, for indicative energy pricing. UAE and US Mag propose use of a percentage of the Palo Verde day-ahead electric price index capped at the IRP deferrable heat rate times the natural gas price index plus transportation cost for transactions whereby the QF gives day ahead notice. For all other non-firm transactions, UAE and US Mag agree with using PDDRR results.

Testimony at hearing reveals illiquid markets in day-ahead, non-firm, peak and off-peak hour electric markets at Palo Verde. Specifically, the data shows some days in which zero volumes of peak hour transactions occurred and many days in which zero volumes of off-peak hour transactions occurred. These are the markets in which parties expect the Company to sell QF energy delivered, unrequested, with day ahead notice and means the Company may not be able to sell the power at all and thus be forced to back down its other, lower cost resources so that loads and resources are in balance. Therefore, the Company, Division and Committee contend that purchases of QF power at a percentage of Palo Verde index prices, when the avoided cost may well be the lower cost of backing down a coal plant, violates the ratepayer indifference standard. We concur and approve the PDDRR method for pricing non-firm energy delivered by the QF at its sole discretion.

6. Price Adjustments

The Company, Division and Committee support avoided cost determination based on the QF's proposed operating conditions. PDDRR results will reflect QF dispatchability, reliability and availability. For the QF to be paid for avoiding capacity, it must meet the availability of the avoidable resource. We accept these adjustments.

C. TRANSMISSION AVOIDED COSTS

Parties agree avoidable transmission capital costs and losses should be included in indicative pricing and that these costs should be determined on a case-by-case basis. Parties disagree how to approach this.

UAE and US Mag propose avoided transmission capital cost be calculated as the pro rata share of the transmission capital costs associated with the next deferrable plant in the Company's IRP, unless the delivery site of the QF would not avoid such costs. Avoided transmission losses should be calculated case by case based on the QF site relative to the deferrable plant.

The Company, Division and Committee propose convening a work group to recommend to the Commission a method to identify the costs, savings and timing of avoidable transmission costs, within 21 days of the date of this order. The method is based on a case-by-case analysis performed within the existing time frame of Schedule No. 38 requirements. Currently a QF already must request from the Company's transmission organization a transmission study for the QF interconnection. These parties propose this study should be expanded to include analysis of any possible transmission avoided costs. The Division argues a case-by-case look is necessary because the IRP deferrable resource is simply a proxy for a subsequent Request for Proposals ("RFP") process to actually acquire a plant. The Division notes the currently proposed RFP includes a Lakeside unit as an eligible site that does not require the Mona transmission upgrade. The Company argues transmission capital costs are not avoidable to the same extent and in the same manner as generation plant or purchased power costs. The size and timing of transmission investment may be influenced by factors other than the incremental proxy plant. The Company explains if it were to pay the QF a cost based on avoiding a transmission investment and the investment were to go forward for other reasons, ratepayers will have paid twice for the transmission investment. The Company argues a specific study must be performed to identify both the costs and benefits of transmission relative to the existence of the QF.

We are persuaded that further examination is required to better understand the relationship of avoidable generation capital cost to avoidable transmission capital cost and losses for QFs subject to Schedule No. 38. We order formation of the proposed work group and await its report in 21 days.

D. WIND QUALIFYING FACILITIES GREATER THAN THREE MEGAWATTS

1. Avoided Cost Method for Wind QF Resources up to the IRP Target

All parties agree a Proxy approach for determining the avoided generation capacity and energy costs associated with a wind QF is appropriate for meeting the IRP planned acquisition of cost effective wind resource, the IRP target amount. The IRP target amount is defined as an accumulated target, currently 1,400 megawatts, with annual overages and underages rolled forward for the next year.

Parties agree with the Division's testimony that the Proxy method provides reasonable results when: 1) the operating characteristics of the proxy plant closely match those of the QF being evaluated; 2) the QF exactly replaces the entire capacity and energy of the proxy plant; and 3) the QF does not significantly affect other plant additions or system operations. While parties did not agree this held true for other types of QFs, they testify the unique characteristics of wind resources warrants such an approach. For example, the IRP selects as cost effective an amount of wind resource based on an analysis of managing risks associated with natural gas fuel price volatility and potential climate change policy in the context of the IRP future resource portfolio. Wasatch Wind testifies that the appropriate deferrable plant for a wind QF is the Company's IRP planned wind resources. Once the IRP wind resources are used as the next deferrable IRP resource in the PDDRR method, Wasatch Wind argues the IRP wind resource cost estimates and the PDDRR results are expected to be the same. Thus the two methods yield similar results and the simpler of the two methods, the proxy method should be adopted. However, parties do not agree on whether to use IRP wind cost estimates as the deferrable plant costs, or whether market-based wind prices are more appropriate.

Pioneer argues that many controversial assumptions are required in the IRP to calculate the IRP wind resource cost and therefore proposes a market proxy. For objectivity, simplicity and transparency, Pioneer proposes that price be set at PacifiCorp's most recent market-based wind contract executed pursuant to its renewable resource RFP. Pioneer provides this contract in confidential testimony. Pioneer argues there is no evidentiary basis for many of the pricing determinations for wind projects proposed in this case. The estimates of integration cost and capacity credit, Pioneer argues, are subjective and controversial and that the only non-subjective actual evidence available is the last non-QF wind contract entered into by PacifiCorp. Pioneer testifies that the annual prices of the last wind contact can be transferred to a QF wind project price by converting the annual prices into peak hour and off-peak hour prices and adjusting the price for wind site and project specific characteristics.

The Committee agrees with the proxy approach and proposes avoided cost be calculated as the lower of the IRP (or IRP update) wind resource cost or market price. Market price is determined by the lowest executed bid for a wind resource from the most recent renewable, market-based RFP, i.e., the winning bid. The Company and Division support the Committee's approach. In taking this approach, the Committee argues, Utah customers should be reasonably indifferent to PacifiCorp buying power from either its own developed and built wind resource, an RFP-based wind resource or a wind QF. All payments to the QF are proposed to be on a volumetric basis, dollar per megawatt hour.

Wasatch Wind proposes a proxy that is the average of the IRP cost estimate and the price from the most recent RFP wind contract. This approach, Wasatch Wind testifies, will avoid gaming in the IRP process and is a compromise of the proposal to provide indicative prices for QF wind power at the lower of the IRP cost proxy or RFP wind market price proxy. Wasatch Wind identifies what it sees as a mismatch in the IRP wind cost estimates used by the Company, Division and Committee. Specifically, a Wyoming wind capacity factor is used but no transmission to bring the power to load is included in the cost.

We are persuaded for the reasons stated by parties above that the proxy method best reflects the avoided cost of a wind QF up to the IRP target level of wind resources. This IRP target level of wind resources is not an annual target, but the cumulative target from the IRP and we decline to limit the use of the proxy method to 200 megawatts per year. Further, we accept the market price proxy as it is reasonably accurate but also simple and transparent. Administratively determined cost estimates are necessary for planning but in the end are simply the best estimates available at a point in time; a market-determined price should provide a better reflection of an actual, cost-effective wind resource. Further, in hearing, the Company testified that in future renewable RFPs, it will have a Company built next best alternative as a benchmark cost for other wind projects to compete against. Since the payment to a wind QF is the same as a wind resource procured through competitive bidding, the ratepayer indifference standard is addressed yet simplicity in identifying the cost of a wind resource is achieved.

Parties agree that project specific adjustments shall be made to account for differences in the QF wind profile when compared to the proxy wind resource. Wasatch Wind and Pioneer add transmission cost differences to this list and Wasatch Wind further adds differences in transmission costs and benefits and line losses. We agree all of these factors are worthy of consideration in determining an indicative price for wind. We find the most recently executed RFP contract, prior to the QF's request for indicative pricing, will serve as the proxy against which project specific adjustments are made to produce an indicative price for wind QFs in Utah. The most recently executed contract becomes a rolling target as new RFP contracts are executed.

2. Avoided Cost Method for Wind QF Resources Exceeding the IRP Target

The avoided cost method recommended by parties for QF wind projects that exceed the IRP target level of wind supply is the Proxy method for avoided generation capital cost and the PDDRR method for avoided energy cost. Thus, once the next deferrable IRP resource is no longer a wind resource, wind QF indicative pricing will be based, as it is for non-wind QFs, on the Proxy and PDDRR methods used for non-wind QFs discussed in Section A of this order with a few distinctions. The first is that only volumetric pricing will be available to the wind QF. No party disagrees with this. However, parties disagree on two other specific adjustments to be made to the Proxy/PDDRR calculations to account for the wind QF: how much avoided capacity cost should be reflected in payments to wind QFs and how much cost should be assumed in pricing to account for the cost of integrating the wind QF into the Company's system.

All parties agree wind QFs in excess of the IRP target level of wind resource would receive a volumetric price based on peak and off-peak prices. The Company and Division propose volumetric pricing for wind QFs that converts the next deferrable IRP resource avoided capacity cost to volumetric pricing in peak hour prices. The Company proposes to pay 20 percent of avoided capacity costs. The 20 percent capacity payment would be included solely within on-peak hours in such a way that a 35 percent on-peak capacity factor wind resource would get exactly a 20 percent capacity payment. The Committee supports the Company proposal but is not opposed to raising the capacity payment to 30 percent. The Division agrees with the Company's 20 percent position as a starting point but states the percentage of capacity payment should be updated as better information becomes available.

Wasatch Wind and Pioneer propose full capacity payments be available for energy delivered in peak hours. Thus, a wind facility with a 35 percent capacity factor in high load hours would receive 35 percent of avoided capacity cost. Wasatch Wind argues further discounting to 20 percent represents a double adjustment.

It is our understanding that the 20 percent capacity credit is used in planning to ensure reliable supply of power at peak. We are now addressing a payment issue rather than a planning issue and concur with Wasatch Wind and Pioneer that wind power delivered in high load hours should receive a capacity payment consistent with the wind QF capacity factor in high load hours.

3. Integration Costs

The Company defines the cost to integrate wind resources into its utility system as twofold: the cost of holding incremental operating reserves to accommodate wind generation on the system and maintain reliability and the expected higher operating costs due to the variable and relatively uncontrollable nature of wind generation which it refers to as "imbalance" cost. In its IRP 2004, the Company estimates the cost for imbalance at $3.00 per megawatt hour. It estimates the cost of incremental reserves assuming the need to integrate 1,000 megawatts into the system. When the cost of incremental reserves and inflation are added, the Company estimates the 20-year levelized cost in 2004 dollars to be $4.64 per megawatt hour. This cost is deducted from the PDDRR avoided energy cost results and therefore reduces payments to wind QFs. The Committee and Wasatch Wind concur with this estimate but the Committee also recommends the Commission order the Company to explore calculating integration costs directly through the GRID model.

The Division testifies that it supports the Company's method for estimating integration costs but believes the assumption of 1,000 megawatts wind penetration is too high and overstates wind integration costs at this point in time. The Division cites a study by Xcel Energy that shows integration costs increase with the penetration level of wind resource and this study estimates costs in the range of $2 to $4 per megawatt hour. The Division argues we do not know what the actual penetration of wind resource will be in the eastern control area but it may well be less than 1,000 megawatt hours and recommends $3.00 per megawatt hour, the midpoint of Xcel's range, as a reasonable starting point. Further, the Division recommends revisiting this cost estimate as soon as 300 megawatts or 10 new wind facilities are added, whichever comes first.

We find the Division's starting point is reasonable given the 1,400 megawatts of wind resource is estimated in the IRP 2004 to come from both the western and eastern control areas. The Division's recommendation to revisit this issues as real data becomes available is also reasonable and we hereby adopt it.

4. Renewable Energy Credit Ownership

The IRP 2004 recognizes the value of a Renewable Energy Credit ("REC"), a tradeable value in emerging markets, and includes this value as a credit in the evaluation of wind versus alternative supply-side resources. A value of $5.00 per megawatt hour is attributed for the first five years of service and this value declines with inflation in real terms.[1] Based in part on this credit to the cost of wind, the IRP selects 1,400 megawatts of wind power as cost effective.

All parties agree that if PacifiCorp pays for the RECs, it owns the RECs. The Company additionally proposes that it own the RECs if pricing is based on either the IRP wind resource proxy or the RFP market based price proxy. Since we adopt the RFP market-based

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[1] Appendix J of IRP 2004.

price proxy rather than any combination that would include the IRP wind resource proxy, we focus our consideration with respect to market-based wind contracts. In the RFP wind contract on record in this case, PacifiCorp paid for the RECs and therefore owns the RECs and the price includes the value of the RECs. Wasatch Wind and Pioneer propose allowing wind QFs to buy back the RECs at the IRP value and retain ownership of the RECs at its choice. When asked in hearing if it could support this proposal, PacifiCorp said it would respond the next hearing day. We have no record of a response from PacifiCorp on this proposal. In the end, we find the issue is a contractual matter between the QF and PacifiCorp. We reason that ratepayers should be indifferent whether PacifiCorp never pays for the RECs or if it buys and then sells them. Therefore, we approve Wasatch Wind and Pioneer's proposal allowing QFs to buy back the RECs at the IRP value if PacifiCorp owns the RECs in the last executed wind market-based RFP contract.

E. ACCOUNTING ISSUES

PacifiCorp testifies QF contracts may cause the Company to incur additional costs due to direct or inferred debt impacts on its financial statements and seeks to reduce its QF payments for power by the additional debt-related costs. The Company states the Emerging Issues Task Force 01-08, Financial Accounting Standard 13 and Financial Interpretation 46R require the Company to review QF contracts executed or modified after July 1, 2003 to determine 1) if it contains a lease, 2) if a lease is capital or operating and 3) if the Company is the primary beneficiary. These accounting standards require the Company to recognize its obligations under certain QF contracts as capital lease obligations which are considered debt that impacts both the Company's financial statements and credit quality. The Company further testifies, even if a QF contract is not treated as a capital lease obligation, it may have similar debt impacts pursuant to Financial Interpretation 46R and/or it would have similar debt-like impacts on the Company under guidelines established by rating agencies; these debt impacts impose additional costs on the Company; the additional costs are related to the increase in equity required to offset the QF-related inferred or imputed debt and allow the Company to maintain its credit quality; the cost is calculated as the difference between the pre-tax cost of equity and the pre-tax weighted average cost of capital times the amount of equity needed to re-balance the capital structure; the debt utilized should be the higher of the debt directly added to the Company's balance sheet due to accounting rules or the debt determined by the most transparent rating agency method; Standard & Poor's is the most transparent and uses a 50% risk factor which is multiplied by the present value of the capacity payments discounted at 10%; the Standard & Poor's method and risk factor should be used to compute the debt-related costs of QFs; QF payments should be reduced by the additional debt-related costs calculated on an agreement-by-agreement basis; and if these debt-related costs are ignored QF power is incorrectly priced and customers ultimately bear these costs.

The Division testifies the debt arising from QF contracts may affect, directly or indirectly, the cost of capital of the purchasing utility; it supports the Company's proposed treatment for capital leases; it recommends using a minimal risk factor of 15% for imputed debt by rating agencies given the ambiguities of the actual impact on the Company's cost of capital; and the debt-equivalence adjustment to QF payments should apply on an incremental basis to all QFs except those under Schedule No. 37. The Division cites reports from the Energy Information Administration, Lawrence Berkeley Laboratory and Electric Power Supply

Association, stating the first report finds no conclusive evidence that power purchases from non-utility generators raised the utility's cost of capital, the second report finds no evidence to support the debt-equivalence hypothesis, and the third report says it is difficult to ascribe any particular utility's credit rating to a single factor such as the size of purchase power obligations. The Division testifies Utah QFs are pre-approved through the regulatory process and pose little risk of non-recovery; Standard & Poor's indicates the passage of the Energy Resource Procurement Act, Utah Code 54-17-101 et seq. ("SB 26") implies the use of a lower risk factor for future Utah power purchase agreements that fall under the protection of the new legislation; there is a lack of empirical evidence supporting the debt equivalence hypothesis and the Division recommends they update the Lawrence Berkley study with the cooperation of the Company.

US Mag testifies it opposes the imputation of virtual debt on specific QF contracts saying it seems arbitrary and unreasonable and little more than another artificial barrier to QF development and cites the findings of the same Energy Information Administration 1994 study raised by the Division.

Wasatch Wind testifies it opposes the debt imputation for wind QF projects as the size of contemplated wind projects should not have a material effect on the capital structure of PacifiCorp, many variables determine the debt rating of a major corporation the size of PacifiCorp, and wind contracts can be negotiated to avoid the fixed charges of a power purchase agreement that causes investors concern.

UAE testifies the Company's proposed debt imputation for QF projects should be rejected saying the vast majority of states have not imputed any such costs to QFs, Utah businesses should not be penalized with imputed costs that other states refuse to impose, SB 26 should allow the Company greater assurance of cost recovery from resource acquisitions, Standard & Poor's states in its May 5, 2005 credit rating report on PacifiCorp that SB 26 "should substantially increase the utility's prospects for cost recovery", the Oregon Commission stated in its February 18, 2004 order it was not persuaded that the new FASB standards would have a negative effect on PacifiCorp, it would be a deterrent to Utah QF development, and states that power purchase obligations is but one of 88 cited factors considered by rating agencies such as Standard and Poor's and Moody's in determining the credit rating for PacifiCorp and utilities.

We are persuaded by UAE's evidence of 88 factors considered by rating agencies in the determination of a utility's credit rating, the potential impact of SB 26 on the Company's credit rating, the Division's reference to the insufficient empirical evidence to support the debt equivalence hypothesis and the unsupportive (of debt adjustments) findings of the studies mentioned on this record, and that it is unclear how individual QF contracts may affect PacifiCorp's credit rating and therefore cost.

F. CONTRACT ISSUES

1. Contract Term

PacifiCorp testifies contracts for the required purchase of power from QFs should be limited to a term of 20 years since the longer the term, the greater the risk to the Company and ratepayers of incurring an uneconomic power purchase agreement; the 20 year term represents an appropriate balance between a term that allows the QF to secure financing and limiting the risks that accompany long range power price forecasting; the QF may continue to sell power to the Company under PURPA requirements after the initial contract term; the contract term does not limit the period in which a QF may recoup its investment, it merely limits the period for which pricing is based on a snapshot projection of avoided costs; and the QF may petition the Commission for an exception to the 20 year contract term limit.

The Division and the Committee testify they support the Company's proposed standard limit of 20 years for a QF contract and allowing the QF to petition the Commission for an exception to the 20 year contract term limit.

UAE testifies the 20 year contract limit for QF penalizes the QF and creates uncertainty as to whether the QF will receive the real levelized capacity payment over the remaining 15 years of a plant with a 35 year life. UAE, US Mag and Wasatch Wind support a standard term of 20 years for QF contracts if the tariff allows QFs to petition the Commission for longer term contracts.

We find reasonable and accept the parties' common position providing for a standard term limit of 20 years for QF contracts with the allowance for parties to petition the Commission for longer terms.

2. Levelization

UAE testifies QF capacity payments for a 20 year contract should be levelized over the 20 year term even if the early years do not include avoided capacity costs and short-term QF capacity payments should be based on a Simple Cycle Combustion Turbine ("SCCT") for shorter term contracts. The Company opposes this adjustment arguing that the avoided front office transactions already address avoided capacity and to add SCCT avoided costs would double count avoided capacity costs.

PacifiCorp, the Division and Committee support levelizing QF capacity payments over the term of a 20 year contract given sufficient security to protect ratepayers in the event of default. They do not support levelization for short-term QF contracts.

US Mag supports an option for levelized capacity payments over the contract term and any security should be dealt with on a contract-by-contract basis. Wasatch Wind believes no security is needed for levelization of contracts as levelization by its very nature pushes cost recovery back when compared to rate making treatment received by the Company.

We find levelizing the capacity payments to QFs over the full 20 year contract term will aid in their financing. Where security is needed to protect ratepayers in the case of default by the QF, its form should be negotiated on a contract-by-contract basis.

3. Issue Resolution

PacifiCorp, Division, Committee, UAE, US Mag and Wasatch Wind all believe there is already a process in place to resolve disputes involving QF contracts or the negotiation of such and all agree that the Company's Tariff Schedule No. 38 should have language informing QFs of available informal and formal dispute resolution procedures. We concur and direct the Company to work with parties to develop a proposed revision to Schedule No. 38 incorporating language informing QFs of available informal and formal dispute resolution procedures.

G. METHODOLOGY VS PRICE

PacifiCorp states the purpose of this docket is to approve a methodology for determining avoided capacity and energy costs to be paid to QFs and not to determine specific illustrative prices for those payments. The Company believes numeric comparisons to other proposals can not accurately be made because the results of the avoided costs calculations will be QF specific and will include updated information on market prices and other factors. The Division and Committee state the purpose of this docket is to determine only an approved method and not illustrative prices. Both UAE and US Mag believe illustrative avoided capacity and energy costs should be approved by the Commission in this docket. Having earlier in this order decided upon a method of calculating avoided capacity and energy payments for QFs, we concur with the Company, Division and Committee that in this docket we will not decide on specific illustrative QF payments. Schedule No. 38 requires the Company to provide indicative prices upon a QF's request. As we have now set the method to be used, indicative pricing can be given by the Company for each unique request submitted by QFs.

H. QFS 100 MEGAWATTS OR GREATER

PacifiCorp testifies that avoided capacity and energy payments for QFs 100 megawatts or greater and seeking a contract term of ten years or more should be based on the QF winning a competitive bid in the process adopted in the Energy Resource Procurement Act, 54-17; the losing QF bidders would still be entitled to avoided energy payments based on the PDDRR method, but not entitled to avoided capacity payments; this bidding process requirement for large QFs is consistent with SB 26 requirements; and QFs may petition the Commission for a waiver of the 100 megawatt limit based on the provisions of SB 26. The Division, Committee and US Mag testify in support of PacifiCorp's proposal for QFs 100 megawatts or greater. No party opposed this position.

We concur with parties' position and will require QFs 100 megawatts or greater and seeking a contract term of ten years or more to participate in a bidding process whereby the winning QF bid will receive the bid avoided capacity and energy payments while the other bidders will only receive energy payments based on the PDDRR method. We also find QFs may petition the Commission for a waiver of the 100 megawatt limit based on the provisions in SB

26. We direct the Company to work with parties to develop a proposed revision to Schedule No. 38 incorporating language informing QFs of the bidding process requirements for QFs 100 megawatts or greater and seeking terms of ten years or more.

I. AVOIDED COST MODEL UPDATES

During the hearing, the issue of transparency was raised regarding changes made to the GRID model used in calculating avoided costs. We will require the Company to keep a record of any changes, including data inputs, made to the Proxy and GRID models used in this case. The Company shall notify the Commission and Division of any updates they make to the models used in the approved Proxy and PDDRR methods. The Division is directed to review these updates.

III. ORDER

Wherefore, pursuant to our discussion, findings and conclusions made herein, we order:

Cogeneration Facilities Between 1 and 100 Megawatts and Small Power Production Facilities, Excluding Wind, Between 3 and 100 Megawatts

1. The Proxy method, based on the next deferrable IRP resource as proposed by the Company and described in this order is approved for calculating avoided generation capacity costs to provide indicative pricing to QFs.
2. The Partial Displacement Differential Revenue Requirement method as proposed by the Company, Division and Committee and described in this order is approved for calculating avoided energy costs to provide indicative pricing to QFs for a fixed price

payment option for QF power dispatched by the Company. This method, with one adjustment, is also approved for a fixed price payment option for non-dispatchable energy delivered by the QF. The one adjustment is that avoided energy cost is capped at the fuel cost of the deferrable IRP resource.

3. We approve a variable pricing option or "tolling" option for dispatchable QF energy output using the Company's relevant fuel costs multiplied by the deferrable IRP resources heat rate.

4. Non-firm transmission shall be included in the PDDRR method using a 48 month history.

Transmission Avoided Costs

5. We direct the Company to convene a work group to recommend a method to identify the costs, savings and timing of avoidable transmission costs, for QFs subject to Schedule No. 38, within 21 days of this order.

Wind Qualifying Facilities Greater than Three Megawatts

6. We approve a market price proxy for determination of avoided costs for wind QFs up to the Company's IRP target megawatt level of wind resources. The Company's most recent executed wind contract from its Renewable RFP will serve as the proxy against which project specific adjustments are made to produce an indicative price for wind QFs in Utah.

7. For wind resources exceeding the IRP target, wind QF indicative pricing will be based, as it is for non-wind QFs, on the Proxy and PDDRR methods.

8. Wind power delivered in high load hours should receive a capacity payment

consistent with the wind QF capacity factor in high load hours.

9. We approve the Division's recommendation of $3 per megawatt hour for wind QF integration costs as a starting point. This value is to be revisited as soon as 300 megawatts or 10 new wind facilities are added, whichever comes first.

10. REC ownership is a contractual issue between the QF and the Company. QFs will be allowed to buy back the REC at the IRP REC value if the Company owns the REC in the last executed wind market-based RFP contract.

Contract Issues

11. The standard term for QF contracts is 20 years with the allowance for parties to petition for longer terms.

12. QF capacity payments may be levelized over the full 20 year contract term. Where security is needed to protect ratepayers in the case of default by the QF, its form should be negotiated on a contract by contract basis.

13. The Company is directed to work with parties to develop a proposed revision to Schedule No. 38 incorporating language informing QFs of available informal and formal dispute resolution procedures. Also the revision should include language informing QFs of the bidding process requirements for QFs 100 megawatts or greater and seeking terms of ten years or more. We further direct the Company to create on its web site (with reference to this site shown on Schedule No. 38) a transparent check list or table which incorporates the decisions in this order and allows QF developers to view the process for determining indicative pricing.

QFs Greater than 100 Megawatts

14. QFs 100 megawatts or greater and seeking a contract term of ten years or more must participate in a bidding process whereby the winning bid will receive the bid avoided capacity and energy payments while the other bidders will only receive the bid avoided energy payments based on the PDDRR method. QFs may petition for a waiver of the 100 megawatt limit based on the provisions in UCA 54-17-201 (3).

Model Updates

15. The Company is directed to keep records of changes to the models used in the Proxy and PDDRR methods approved in this case, to notify the Commission and Division of any updates it makes to the models, to provide reasonable training on these models at no fee and to continue its efforts to provide internet access to the GRID model.

This Report and Order constitutes final agency action on PacifiCorp's Application. Pursuant to U.C.A. §63-46b-12, an aggrieved party may file, within 30 days after the date of this Report and Order, a written request for rehearing/reconsideration by the Commission. Pursuant to U.C.A. §54-7-15, failure to file such a request precludes judicial review of the Report and Order. If the Commission fails to issue an order within 20 days after the filing of such request, the request shall be considered denied. Judicial review of this Report and Order may be sought pursuant to the Utah Administrative Procedures Act (U.C.A. §§63-46b-1 et seq.).

DATED at Salt Lake City, Utah, this 31st day of October, 2005.

/s/Ric Campbell, Chairman

/s/Ted Boyer, Commissioner

/s/Ron Allen, Commissioner

Attest:

/s/Julie Orchard
Commission Secretary
G#46342