Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Mark R. Tallman, my business address is 825 NE Multnomah, Suite 600, Portland, Oregon 97232, and my present position is Managing Director of Trading & Origination, Commercial & Trading.

Q. How long have you been the Managing Director of Trading & Origination?

A. I have been the Managing Director of Trading & Origination since September 12, 2003. Prior to that date, I worked in the Origination Department, first as an Originator (beginning March 1995), then as the Manager of Origination (beginning January 1999), and finally as the Director of Origination (beginning September 2000).

Q. What did you do before working in the wholesale side of PacifiCorp's business?

A. I served in a variety of roles in PacifiCorp's engineering organization and retail distribution organization, including five years as a District Manager. I have worked at PacifiCorp for nearly 20 years.

Q. Please describe your educational history.

A. I have a Bachelor of Science degree in Electrical Engineering from Oregon State University and a Masters of Business Administration from City University. I am also a Registered Professional Engineer in the states of Oregon and Washington.

Purpose of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide information regarding the prudence of the Company's supply-side resource acquisitions since 2000. (Resource acquisitions prior to 2000 are presented in the Joint Report, which is presented as part of Mr. Duvall's testimony.)

Q. Would you please summarize your testimony in this proceeding?

A. My testimony will demonstrate the prudence of the Company's acquisition of the following supply-side resources: the lease agreement for the West Valley project (West Valley Lease); the Gadsby project; the Currant Creek project; long term power purchase agreements (PPAs) with two wind projects, Eurus Oregon Wind Power Development LLC (Eurus) and Wolverine Creek Energy LLC (Wolverine); long-term PPAs with two Qualifying Facilities (QFs), Desert Power and US Magnesium (US Mag); a long-term PPA with Deseret Generation & Transmission Cooperative (DG&T); and two generation-related agreements – a five-year generation credit agreement with Kennecott Utah Copper Corporation (Kennecott) and a five-year operating reserve agreement with US Mag. These acquisitions are discussed in order in the testimony that follows.

I. West Valley Lease

Q. Please provide a general description of the West Valley Lease.

A. The West Valley Lease is a 15-year operating lease between PacifiCorp and West Valley Leasing Company, LLC, for the output of a 200 MW gas-fired, simple-cycle combustion turbine electric generating station. The generating station consists of five nominal 40 MW units in West Valley, Utah near Salt Lake City. Exhibit No.___(MRT-2) is a copy of the West Valley Lease. West Valley Leasing Company, LLC, is a subsidiary of PPM Energy which, at the time, was doing business as PacifiCorp Power Marketing (PPM). The West Valley project's units became operational during the summer of 2002. The West Valley project has access to natural gas from both the Questar and Kern River pipelines.

Q. How did the Company make the decision to acquire the West Valley Lease?

A. PacifiCorp's service territory is divided into East (Wyoming, Utah and Idaho) and West (Oregon, Washington, California) electrical control areas. PacifiCorp's East control area, which is summer peaking, has experienced consistent growth in recent years. As a result, there was a growing imbalance between summer peak load requirements and the resources to meet it. Prior to the construction of the Gadsby Project and the acquisition of the West Valley Lease, PacifiCorp projected a resource shortage in Utah of 439 MW in July 2002, increasing to 1,262 MW by July 2009. In particular, PacifiCorp projected a need for additional flexible generation resources to allow it to meet seasonal East-side peak demand.

Q. What process was followed to acquire the West Valley Lease?

A. In September 2001, PacifiCorp issued an RFP soliciting bids for resources in excess of 25 MW and capable of delivery in or to its East control area beginning in the summer of 2002. Attached as Exhibit No.___(MRT-3) is a copy of PacifiCorp's RFP. The RFP was issued in response to projections that the Company would experience a shortage of resources. The Company's goal was to secure cost effective resources to meet its East-side capacity requirements.

Q. What level of response did the RFP receive?

A. The RFP generated 52 proposals from 27 different parties. The proposals varied widely in terms of the type of product offered and the date of availability of the resource.

Q. What steps were taken to ensure an unbiased selection method?

A. PacifiCorp took prudent and direct steps to ensure an unbiased evaluation of all proposals. For example, PacifiCorp's legal department "blinded" the proposals so that those evaluating them would not know the identity of the sponsoring company. Similarly, PacifiCorp hired a respected independent consultant to monitor and review the RFP process for non-discriminatory practices and fairness.

Q. Please describe the initial evaluation process for the RFP responses.

A. After an initial credit evaluation, the responses were separated into tiers based on their ability to meet the Company's short-term resource needs. For example, bids in the first tier had to be capable of providing firm supply during peak, or super-peak hours, commencing the third quarter of 2002 and with a point of delivery in or to PacifiCorp's eastern control area. The Company then asked a short-list of bidders, those with bids in the first two tiers, to refresh their bids and bid pricing specifically for the summer months during 2002 - 2004.

Q. Why did PacifiCorp focus on short-term resources?

A. During the RFP time period, PacifiCorp was actively engaged in updating its Integrated Resource Plan (IRP), which was due to be completed in December 2002. As a result, long-term supply proposals were held for consideration pursuant to the IRP process.

Q. Please describe the evaluation process for the short-list proposals.

A. PacifiCorp utilized a sophisticated structuring model and accepted industry practices to quantitatively evaluate the net present value based upon the delivery characteristics of the proposals under consideration. Each bid was evaluated based on the following criteria: (1) net value (PV$) against then current market; (2) net value (PV$) per 100 MW of capacity against the then current market; (3) dispatch flexibility (day of calls, day ahead calls, take-or-pay); (4) point of delivery to PacifiCorp's system; (5) delivery period (shaped June through September, annual); (6) capacity delivered (MW); (7) term (3 years, 10 years, other); and (8) firmness (firm, unit contingent). Exhibit No.___(MRT-4C) summarizes the results of these offers.

Q. Please briefly summarize the transactions that resulted from the RFP process.

A. Based on our quantitative analysis of the proposals, PacifiCorp negotiated with three counterparties to consummate the following three transactions: (1) the West Valley Lease, (2) a 100 MW day-ahead call option for delivery of physical power; and (3) a 100 MW day-ahead call option for delivery of physical power.

Q. What other alternatives to the RFP products did the Company consider?

A. Going into the RFP, the Company had projected a summer short position for its eastern control area of 439 MW in the summer of 2002, increasing to 710 MW by the summer of 2004. The Company's alternatives were to try to fill the position with one-size-fits-all power products from the forward markets or to seek out flexible power products from the RFP. Because standardized forward contracts would not have addressed the need for flexible generation resources to meet peak summer demand, PacifiCorp issued its RFP in September 2001.

Q. PacifiCorp rejected several other offers in the RFP. Why were those other offers rejected?

A. The Company rejected the other offers because they failed to provide the necessary flexibility the Company was seeking, offered products that did not meet the Company's needs, or were priced out of the market. Page two of Exhibit No.___(MRT-4C) explains the reasons why certain offers were rejected.

Q. Please describe the lease terms.

A. Under the lease, PacifiCorp has the total responsibility for operation and maintenance of the West Valley Project, provides all of the fuel used by the West Valley Project, and has the exclusive right to dispatch and receive all of the generation from the West Valley Project, as well as all of the use of the West Valley Project to produce ancillary services, such as operating reserves. The lease requires PacifiCorp to make quarterly payments of $749,150 for each of the five units ($14,983,000/year).

Q. Does the lease give PacifiCorp an option to purchase the West Valley Project or terminate the lease?

A. Yes, the lease is very flexible. The lease provides for two options (vesting in years three and six) to either terminate the lease or purchase the West Valley Project. If PacifiCorp elects to exercise either purchase option, the fixed purchase price ($138 million or $123 million, respectively) were, at the time, estimated to be near the then-depreciated book cost for the West Valley Project at the time of the purchase. These options allow PacifiCorp to hedge against changes in market prices and load forecasts in the coming years and then decide which of three paths—continuation of the lease, termination of the lease or outright purchase of the West Valley Project—is the best economic choice. PacifiCorp has elected to not exercise the first termination option, as explained in further detail later in my testimony.

Q. Please describe in more detail how the West Valley Lease addresses the Company's need for additional East-side on-peak resources and provides system benefits.

A. The West Valley Lease gives PacifiCorp full discretion to dispatch and adjust the output of the West Valley project. The West Valley project has quick-start (fast-responding) units that can be deployed as necessary in response to changing load, generation, or transmission conditions on the system. Similarly, the West Valley project can be dispatched based on changing market conditions to either displace higher cost resources or to sell excess power into the wholesale markets.

In addition, the West Valley project provides system benefits by expanding resource diversity, increasing voltage support and reliability, and reducing the risk of incurring unexpectedly high costs associated with wholesale market purchases. This level of flexibility is important to the Company because it enhances the ability of the East control area to recover from the unexpected loss of transmission import capability or the unexpected loss of other generation units. Lastly, because the West Valley project is located in the Company's major load center east of the Cascade Mountains, it avoids transmission costs and constraints historically incurred in meeting summer peak load in the East control area. In summary, the West Valley Lease gives PacifiCorp new and highly valuable flexibility in meeting its load profile, increases system reliability, and reduces the Company's exposure to transmission and energy price risks associated with volatile wholesale markets.

Q. Please describe the benefits of the structure of the West Valley Lease.

A. The structure of the Lease Agreement is particularly beneficial for several reasons. First, as noted above, it allows PacifiCorp full discretion to adjust the output of the West Valley project. Second, the purchase and termination options in the Lease Agreement allow PacifiCorp to hedge against changes in market prices and load forecasts by revisiting the economics of the transaction in three- and six-year windows. These are very attractive contractual provisions, given the recent volatility of the power markets. Finally, because the West Valley project utilizes the same model of generation units as PacifiCorp's Gadsby Project, discussed below, PacifiCorp is able to functionally integrate the resource into the Company as it if were an owned resource. This functional integration allows the Company to pursue efficiency enhancements such as the consolidation of spare parts inventory, the scheduling and procurement of major maintenance activities, and the use of employees in operating other generation projects.

Q. Please describe the operational benefits of the West Valley Lease.

A. The West Valley Lease adds flexibility and diversity to PacifiCorp's generation portfolio. Every power system that serves variable loads requires a blend of generation resources. Even though monthly energy usage may seem relatively predictable, power generation and delivery is dynamic and requires resources that can scale up and down when loads change or other unexpected events take place. Gas-fired generators, like those at the West Valley Project, are a cost-effective option to quickly balance loads and resources. Without flexible generators, PacifiCorp's alternative in its East control area is to ramp up and down other generators that have a lower incremental cost or to rely on third party suppliers who, assuming there are no transmission constraints involved, are willing to transaction for the needed delivery period (such as within the hour, next hour(s), or next day(s)). Reliance on other generators for this type of flexibility can lead to increased operating and repair costs and a decrease in fuel efficiency. Relying on third parties for this type of flexibility involves the risk that third party suppliers will not be sufficiently available. Generators such as the ones being leased allow other generation units in the portfolio to operate efficiently and provide cost-effective flexibility in meeting balancing load/resource requirements. The West Valley quick-start units have performed in just this fashion and have proven to be a valuable addition to PacifiCorp's generation portfolio by providing capacity and energy to the system, displacing more expensive power purchases, reducing transmission expenses and, during times when adequate transmission capability exists, being available for economical wholesale sales.

Q. Why was the West Valley Project structured as a lease instead of a purchase?

A. This transaction was structured as a lease in order to meet summer 2002 load service obligations, respect the validity of the IRP process, and meet the requirements of applicable state/federal laws. Because the transaction involved an affiliate, regulatory approvals for a purchase power contract could not have been accomplished in time to have the resource available to meet the 2002 summer peak. Given the imminence of the IRP, PacifiCorp wished to defer a long-term resource acquisition decision until the Company's position and resource needs became clearer. A lease under the Federal Power Act "safe harbor provision" permitted PacifiCorp to meet these objectives, while complying with all applicable laws and regulations.

Q. Does the West Valley Lease act as a system hedge against wholesale market spikes, such as those that occurred during the 2000-2001 Western energy crisis?

A. Yes. The lease reduces PacifiCorp's exposure to market extremes, which are most pronounced during high demand, system peak periods.

Q. Please describe your financial modeling methodology for the West Valley Lease structure.

A. The Company conducted a real option analysis based on the best market information available at the time, using forward price curves of January 29, 2002 Exhibit No. ___ (MRT-5C) describes the methodology used by the Company to determine the value of the West Valley Lease.

Q. What value did the Company derive for the right to use the plant to convert gas into electricity?

A. The plant was valued as a daily spark spread option (power delivered at Mona vs. natural gas delivered at Opal/Rockies) net of operating costs and benefits and net of taxes. The straight right to use the plant for fifteen years had a value of

$13,225,000 per annum. This number is the discounted free cash flow annuity for the gas/electric conversion value. Any residual value considerations are irrelevant in calculation of the tolling option because there is no up-front purchase payments and no liabilities extending past the end of the lease. Essentially, $13,225,000 per annum is the value of the tolling option premium (the right for PacifiCorp to convert gas to electricity) and does not include the value associated with the two lease termination and plant purchase options.

Q. What specific risks are mitigated through the termination and purchase options in the lease structure?

A. There is always some level of uncertainty over the value of power and gas at points far into the future. Since PacifiCorp is typically able to make electric and gas hedge transactions approximately three to five years into the future, it is prudent and valuable for PacifiCorp to explore leasing provisions that would minimize losses if the gas/electric spark spread collapses or capture additional value for customers if the gas/electric spark spread widens. The lease termination and the plant purchase provisions negotiated for Year 3 and Year 6 of the lease serve to mitigate those risks.

Q. How were the values for termination of the lease and plant purchase determined?

A. Black-Scholes option theory was used to value the special termination/purchase provisions. The option to abandon the lease was valued as a put option with the strike equal to the Net Present Value ("NPV") of the remaining lease payments against the underlying asset price (i.e., NPV of free cash flows for the remaining lease period).

The option to purchase the plant is a call option with the strike at the net book value against the underlying asset price (i.e., NPV of free cash flows until the end of the assumed book life plus the liquidation of remaining assets). To value the first purchase option, the Company explicitly calculated the residual value of the plant based on the best market information available. The nominal value of the put and call options in Year 3 of the lease is in excess of $28,568,000. For these options in Year 3 and Year 6, PacifiCorp did not have to make any up-front payment at the beginning of the lease. Instead, a premium is included in the annual lease payment. Therefore, if PacifiCorp exercises either of the lease termination options, PPM will not receive full payment for the options it granted. The inferred annualized contract option premium is $1,758,000 (the difference between the lease payments of $14,983,000/year and the $13, 225,000/year value of the gas/electric conversion option). This amount is lower than the amount determined by amortizing the $28,568,000 option value referenced above over the life of the lease ($2,110,000/year).

Q. What risk mitigation characteristics do put and call options provide?

A. A put option owner has the right to sell or deliver (put) an underlying asset on a certain date at a predetermined price (strike price) to the put option seller. A put option buyer mitigates price or value risk if the underlying asset price moves downward. A call option owner has the right to buy or receive (call) an underlying asset on a certain date at a predetermined price from the call option seller. A call option buyer mitigates price or value risk if the underlying asset price moves upward. The owner of both a put option and call option hedges both downward and upward price or value risk.

Q. What economic benefit does the lease structure provide?

A. By adding the value of the annual tolling option premium of $13,225,000 and the value of the lease termination and purchase option premium of $2,110,000 per year, the fair market value of the lease payment was $15,335,000 per annum. The lease payment of $14,983,000 per annum is below market and therefore beneficial to PacifiCorp's customers. In addition, the put and call options in Year 6 have significant value but were left out of the valuation analysis, demonstrating that additional value is associated with the West Valley Lease but, in order to be conservative, was not evaluated.

Q. Is it possible to mitigate the market risk of future higher or lower implied market heat rates that will affect the value of the plant?

A. Yes. Options to terminate a lease (put options) provide protection if the gas/electric spread collapses and drives the implied market heat rate below the heat rate of the West Valley Project. Options to purchase the West Valley Project (call options) provide protection if the gas/electric spread increases and drives the implied market heat rate above the plant heat rate.

Q. What information regarding the decision to acquire the West Valley Lease was presented to the Board of Directors?

A. The Board of Directors was briefed on the terms of the West Valley Lease and an economic analysis of the proposed project was presented. These documents are attached as Exhibit No.___(MRT-6C). The Board of Directors granted approval to ratify the West Valley Lease on March 4, 2002.

Q. Has PacifiCorp exercised its option with respect to termination of the West Valley Lease in year three?

A. Yes. The first early termination option provided PacifiCorp with the ability to issue a termination notice on or before June 1, 2004 with the additional PacifiCorp option to rescind the notice on or before September 30, 2004.

Q. Did PacifiCorp decide to retain its lease option on the West Valley plant for an additional three years?

A. Yes. Had the Company not rescinded its notice of termination, the lease would have terminated as of June 2005. Since the Company did rescind the notice of termination, the lease will continue through at least May 31, 2008. The second option requires PacifiCorp to provide notice of termination by December 1, 2006. If such a notice is given, and the Company desires to rescind it, the notice to rescind must be delivered by June 30, 2007.

Q. What steps did PacifiCorp take to thoroughly review alternatives to the West Valley Lease?

A. PacifiCorp issued RFP 2004-X to seek potential resources to replace the West Valley Lease. A copy of RFP 2004-X is included as Exhibit No.___(MRT-7). The Company solicited resource alternatives that would be available by June 1, 2005 for terms of: (1) three-years, (2) three-years with a nine-year extension at the option of PacifiCorp, or (3) up to twelve-years with a three-year minimum term.

Q. What was the response to the RFP 2004-X?

A. RFP 2004-X yielded intent to bid forms from six counterparties with three counterparties ultimately choosing to submit proposals. Proposals from the three counterparties fell into three categories: (1) a 150 megawatt market purchase for 3-years, (2) a 140 megawatt purchase for more than 12-years associated with a to-be-constructed 10,000 mmbtu/kWh natural gas fired plant, and (3) a 200 megawatt purchase from the West Valley project contingent on the project being sold to the bidder.

Q. Did PacifiCorp take proper steps to ensure the RFP process was unbiased?

A. Yes. In recognition that the West Valley Lease is an affiliate transaction, the Company retained the services of Lands Energy Inc. (a private consulting firm) to serve the role of RFP process monitor.

Q. What was the basis of PacifiCorp's ultimate decision to rescind the West Valley termination option?

A. The decision to rescind the first termination option was based on a combination of economics, the impact to reliability for our customers, and the impact to PacifiCorp's load/resource position. In consultation with Lands Energy, the three alternatives were narrowed to the 150 megawatt market alternative. This resulted in the Company comparing the attributes of the 3-year 150 megawatt market purchase proposal against the attributes of the West Valley Lease for the same 3-year period. The Company determined: (1) that the economic analysis indicated that the West Valley Lease is more economic than the market purchase alternative, (2) termination of the Lease can lead to a higher risk of customer outages (on both an amount basis and an exposure basis), and (3) the market purchase alternative adversely impacts the ability to balance the load/resource position. (The market purchase alternative did not replace the full 200 megawatts lost by terminating the Lease and would require the Company to utilize allocated firm transmission rights that are otherwise needed to balance the expected position.) Finally, retention of the Lease also retains the second option to continue the Lease, purchase the project, or terminate the Lease. The value of this second option was not included in the economic comparison of the alternative.

Q. What information regarding the decision to rescind the West Valley termination option was presented to the Board of Directors?

A. Attached as Exhibit No.___(MRT-8C) is the presentation made to the PacifiCorp Board of Directors at its September 20, 2004 meeting regarding the decision to rescind the termination notice.

Q. Given the lease will be in effect until the next option exercise period, how does the Company propose to handle the decision it will face with respect to the option to lease, purchase, or reject, effective May 31, 2008?

A. The Company's IRP studied planning scenarios as if the lease was terminated effectively May 31, 2008. This means that the long-term resource planning process was able to take advantage of the second lease option and explore a variety of portfolio alternatives. As a result, the draft action plan for the IRP was determined as if the lease is terminated to take advantage of other more economic resource alternatives such as the emerging intercooled aero combustion turbine design The General Electric LMS 100 natural gas turbines are expected to have heat rates lower than General Electric's LM-6000 design. As the Company is implementing the IRP action plan it will have the added benefit of the second West Valley Lease option in the event more economic alternatives are not viable.

II. Gadsby Project

Q. Please describe the Gadsby Project.

A. The Gadsby Project consists of three highly-efficient, 40 MW, gas turbine generators located in Salt Lake City, Utah. The three units are designated Unit 4, Unit 5 and Unit 6. Unit 4 was first synchronized to the grid on July 10, 2002. Unit 5 was synchronized on July 14, 2002 and Unit 6 was synchronized on July 29, 2002. During the period from July 10 to August 1, 2002, the units were tested at varying loads and the energy was supplied to the grid. On August 1, 2002 all three units were declared commercial and became available for dispatch.

Q. Why did the Company acquire the Gadsby Project?

A. The Company pursued the Gadsby Project because it represented a least-cost, new resource option that was consistent with the demand for summer peak capacity in PacifiCorp's East control area. PacifiCorp determined that it could build and operate the required peaking capacity less expensively than it could purchase such capacity from a third party building a similar dedicated facility in Utah. The Gadsby site already had considerable infrastructure in the form of transmission access, water, operating personnel, and maintenance facilities. Further, the Company already owned emission credits associated with the previously existing Gadsby Plant. These factors contributed to a reduced cost to install the Gadsby Project compared to a new site. As explained below, the Gadsby Project compared very favorably with the resources acquired through the RFP.

Q. Please provide additional detail about the Gadsby Project.

A. The Gadsby Project consists of three 40 MW, simple cycle, General Electric LM6000 “Sprint” gas turbine generators and other equipment typically associated with a gas-fired generating plant. Exhibit No.___(MRT-9C) provides, among other things, a description of the Gadsby Project turbines. The LM6000 is based on an “aeroderivative” design and is the most efficient unit available in its class. In order to meet local air pollution control requirements, the turbines are equipped with the latest pollution control equipment.

Q. What is the cost of the Gadsby Project?

A. The Company’s estimated total cost for the Gadsby Project at the time the acquisition decision was made was $80.4 million. The project was completed below budget; the actual cost of the Gadsby Project is $74 million.

Q. Please explain the design and operating assumptions of the Gadsby Project.

A. The Gadsby Project was designed to be operated when the incremental generation cost is below market and during instances when a resource is required with short notice (as little as ten minutes in some instances) or when PacifiCorp has load service obligations in the East control area and there is no remaining transmission import capability left. Price forecasts at the time indicated that annual average capacity factors in the range of 30-35 percent could reasonably be expected. This capacity factor anticipated that the units would operate during the heavy load hours of the peak seasonal periods and would be off-line during other hours.

Q. Has the Gadsby Project performed in accordance with those initial assumptions?

A. Yes, the Gadsby Project has met and continues to meet expectations.

Q. What would you conclude regarding the construction and operation of the Gadsby Project?

A. The Gadsby Project was completed on time and within budget. It has been, and continues to be, used and useful in providing service to the Company's retail customers.

Q. Have you prepared a comparison of the Gadsby Project with the transactions resulting from the RFP?

A. Yes. Exhibit No.___(MRT-10C) provides a comparison of the Gadsby Project with other tolling transactions from the RFP.

Q. What does the exhibit show?

A. The first column on the left shows the criteria used to analyze the four alternatives. Moving from left to right, the second, third, fourth, and sixth columns summarize the results for the Gadsby Project, West Valley Lease and other transactions. The eighth column from the left (entitled "Physical") summarizes the results for a market-based take or pay on-peak power delivered to Mona.

Q. What do you conclude from the exhibit?

A. The Gadsby Project compares very favorably with the resources acquired through the RFP. In fact, as shown in Exhibit No.___(MRT-10C), the Gadsby Project has the highest NPV benefit ($6,940,631, or $5,783,859 on a per/100 MW basis) of any of the alternatives and an overall relative ranking of number one. As a consequence, the Gadsby Project was the least-cost resource alternative.

Q. Are there any additional benefits of the Gadsby Project that are not captured in the above analysis?

A. Yes. The Gadsby Project adds to the resource diversity of PacifiCorp's generation portfolio, provides voltage support and increases reliability, and reduces the risk of incurring unexpectedly high costs associated with wholesale market purchases. These advantages have value in reliably meeting our obligation to serve and will continue to provide system-wide benefits to the Company's customers over the life of the project.

Q. What information regarding the decision to acquire the Gadsby Project was provided to the Company's Board of Directors?

A. The Board of Directors was presented with information regarding the need for a flexible thermal resources in the East control area. See Exhibit No.___(MRT-9C) for a comprehensive discussion of the need for additional resources. The Board of Directors reviewed various options to meet the demand for summer capacity, including short-term contracts, long-term contracts, purchasing power from a new merchant plant, and having the company construct its own resources. The Board of Directors also reviewed an economic analysis of the proposed project.

Q. Based on this information, what action, if any, did the Company's Board of Directors take?

A. After a careful weighing of the potential costs and benefits, the Board of Directors granted approval for the Gadsby Project on October 26, 2001.

III. Currant Creek Project

Q. On what basis did PacifiCorp determine that the Currant Creek project was needed?

A. On January 24, 2003, PacifiCorp formally published its 2003 IRP. The 2003 IRP concluded that PacifiCorp needed substantial new supply-side resources to meet its projected loads. The Company's recent supply-side resource decisions respond to this conclusion.

Q. How did PacifiCorp implement this aspect of the 2003 IRP?

A. The Company issued RFP 2003-A. A copy of RFP 2003-A is included as Exhibit No.___(MRT-11). The RFP 2003-A process used a blind bid evaluation process wherein bid responses were submitted to an external consultant (Navigant Consulting, Inc. or Navigant), which, in turn, assured that the responses were adequately blinded such that the bidding entity was not known to PacifiCorp. Navigant then supplied the blinded bid responses to the Company for evaluation.

Q. What was Navigant's overall role?

A. Navigant's overall role was: (1) to make certain that the Company evaluated its own build option in a manner that is reasonable, fair, unbiased, and comparable to the extent practicable, against other bids, and (2) to report on whether the process followed by the Company adequately met these objectives. Navigant prepared a report entitled "Navigant Consulting's Final Report on PacifiCorp's RFP 2003-A, dated September 8, 2004." A copy of this report is included as Exhibit No.___ (MRT-12).

Q. What did Navigant's report conclude?

A. Page 48 of the Navigant report concluded that:

> "PacifiCorp executed a fair and consistent process throughout the RFP to identify the most cost effective resources for meeting its projected supply needs. The criteria, tools, and types of personnel used were similar to other resource solicitations used by other investor owned and municipal utilities elsewhere."

Q. Was the decision to construct Currant Creek made due to RFP 2003-A?

A. Yes. Upon evaluating the alternatives presented via RFP 2003-A, the Company determined that the Currant Creek resource was the best alternative.

Q. Did Navigant agree with that decision?

A. Yes. Page 45 of the Navigant report states that PacifiCorp's Next Best Alternative (NBA) "was determined to be the lowest cost resource option within the context of the RFP process."

Q. Please describe the size and location of the Currant Creek resource.

A. The Currant Creek resource is adjacent to the Company's Mona Substation in Juab County, Utah. Phase One of the Currant Creek project consists of two natural gas-fired simple cycle combustion turbine generators, each with a nominal 140 MW capacity, for a total of 280 MW. Phase One of Currant Creek has a planned operation date by the summer of 2005. Phase Two of the project, planned for completion in early 2006, converts the plant to a combined-cycle combustion turbine with a total capacity of 525 MW.

Q. What costs related to Currant Creek are reflected in the Company's revenue requirement in this filing?

A. The Company has included both Phase One and Phase Two of Currant Creek in this filing. Both Phases will be operational before the conclusion of this proceeding, and thus they will both be "used and useful" at the times rates are proposed to become effective in this proceeding. As discussed in Mr. Widmer's testimony, the Company's net power cost calculation reflects the inclusion of both phases of Currant Creek. Mr. Wrigley's testimony describes the revenue requirement calculations associated with the inclusion of this resource.

Q. What is the expected cost of the Currant Creek resource?

A. The total cost of the Currant Creek resource is approximately $359 million. The cost associated with Phase One of Currant Creek is $150 million.

Q. Has the decision to construct Currant Creek been reviewed by any other commission?

A. Yes. On March 5, 2004, the Utah Public Service Commission (Utah PSC) issued an order granting a Certificate of Public Convenience and Necessity authorizing the Company to proceed with construction of the Currant Creek Project. In its Order, the Utah PSC examined five alternative courses of action that the Company could have followed to meet its summer 2005 peak deficiency: (1) rely exclusively on wholesale market power purchases, (2) re-bid the peak bid category of the 2003-A RFP, (3) re-analyze the bids already received, (4) restart negotiations with bidders, and (5) proceed with building a new resource. The Commission found that a review of these alternative actions "shows no better alternative at the present time than proceeding with building a new resource," and therefore concluded that the Currant Creek Project is required by the public convenience and necessity. (Utah PSC Docket No. 03-035-29, March 5, 2004 Order, p. 20)

Q. What information regarding the decision to acquire the Currant Creek project was provided to the Company's Board of Directors?

A. See Exhibit No.___(MRT-13C), which include the presentations made to the Board of Directors in connection with the decision to proceed with building the Currant Creek project.

IV. Wind Facilities

Q. Please describe the Eurus resource.

A. The Eurus resource, also known as the Combine Hills I Project, is a long-term PPA for the purchase of energy generated by a wind plant for delivery to PacifiCorp's 69 kV transmission system in East Walla Walla Valley, Oregon. PacifiCorp's transmission system in this area serves the Company's end-use load in and around Pendleton, Oregon and Walla Walla, Washington.

Q. What is the term and amount of the Eurus PPA?

A. The Eurus PPA is for up to 41 MW of wind generation capability and has a term that expires 20 years following the project's commercial operation date, or December 22, 2023. PacifiCorp entered into the Eurus PPA on June 17, 2003. The PPA resulted from an RFP by the Energy Trust of Oregon (Energy Trust). Under the agreement, PacifiCorp purchases the energy generated by the project and the Energy Trust purchases the renewable resource attributes or "green tags." The Energy Trust then assigns the green tags to PacifiCorp to hold on behalf of Oregon customers.

Q. Please describe the PPA for the Wolverine Creek wind project.

A. The Company on May 3, 2005 announced that it has entered into a PPA with

Wolverine Creek Energy LLC to purchase the output of a 64.5 MW wind project to be constructed in southeast Idaho and interconnected with the Company's Goshen substation. Wolverine Creek Energy LLC is a special purpose entity owned and operated by Invenergy, a developer, owner and operator of power generation and energy delivery assets headquartered in Chicago. The agreement is for twenty years, from December 1, 2005 through November 30, 2025.

Q. What process did the Company follow to make this resource acquisition?

A. This project was acquired as a result of PacifiCorp's renewable resource RFP, designated RFP 2003-B, issued in February 2004 to acquire up to 1,100 MW of renewable resources. The Company's 2003 IRP had identified 1400 MW of renewable resources as part of a least cost portfolio of resources to meet the Company's growing demand over a ten-year period. In response to the RFP, the Company received about 55 bids and 188 bid options, representing approximately 74 separate facilities, from about 35 bidders.

Q. What information was provided to the Board of Directors in connection with the Invenergy resource acquisition?

A. Included as Exhibit No.___(MRT-14C) is the Board presentation from its January 20, 2005 meeting regarding the decision to enter into the PPA for the "Goshen Wind Farm." A subcommittee of the Board subsequently met on April 14, 2005 to approve the final terms of the transaction.

Q. Is the Invenergy project included in Mr. Widmer's calculation of net power costs in this case?

A. No. The final agreement with Invenergy was reached on April 29 and announced on May 3, just two days before the filing of this case. As a result, there was not sufficient time to permit this resource to be reflected in Mr. Widmer's analysis. We will include this resource in the updated net power cost calculation in the Company's rebuttal case.

Q. What is the status of the remaining bids submitted in RFP 2003-B?

A. The Company retains well over the targeted 1,100 MW of capability on our short list for continuing negotiations.

V. <u>QF Purchases</u>

Q. Please describe the Desert Power resource.

A. The Desert Power resource is a long-term PPA for the purchase of capacity and associated energy for delivery to PacifiCorp at Rowley substation.

Q. What is the amount and term of the Desert Power PPA?

A. The Desert Power PPA is for 95 MW and has a term of January 1, 2006 through December 31, 2025. The Desert Power resource is a QF and the PPA was entered into pursuant to PacifiCorp's obligation to purchase under the Public Utility Regulatory Policies Act of 1978, or PURPA. The pricing was determined pursuant to the methodology prescribed by the Utah PSC. (Docket No. 03-0135-14).

Q. What information was provided to the Board of Directors in connection with the Desert Power acquisition?

A. Included as Exhibit No.___(MRT-15C) is the Board presentation from its September 23, 2004 meeting regarding the decision to enter into the Desert Power PPA.

Q. Please describe the PPA with US Mag.

A. The US Mag resource is a long-term PPA for the purchase of non-firm electricity from US Mag's QF in Tooele County, Utah.

Q. What is the amount and term of the US Mag PPA?

A. The PPA was originally proposed as a 36 MW QF with a 20-year term, from January 1, 2005 through December 31, 2024. The Utah PSC (Docket No. 03-035-38) approved a 5-year term, from January 1,2005 through December 31,2010. The pricing was determined pursuant to the methodology prescribed by the Utah PSC (Docket No. 03-0135-14). Just as with Desert Power, the Company was obligated to purchase this output under PURPA.

Q. What information was provided to the Board of Directors in connection with the US Mag acquisition?

A. Included as Exhibit No.___(MRT-16C) is the Board presentation from its October 21, 2004 meeting regarding the decision to enter into the Desert Power PPA.

VI. Deseret Power Generation and Transmission PPA

Q. Please describe the DG&T resource.

A. The DG&T resource is a long-term PPA for the purchase of capacity and associated energy for delivery to PacifiCorp's Mona 345 kV substation.

Q. What is the amount and term of the DG&T PPA?

A. The DG&T PPA is for 100 MW and has a term of June 1, 2005 through September 30, 2024.

Q. What information was provided to the Board of Directors in connection with the DG&T acquisition?

A. Included as Exhibit No.___(MRT-17C) is the Board presentation from its February 19, 2004 meeting regarding the decision to enter into the DG&T PPA.

VIII. Other Agreements

Q. Please describe the generation credit agreement with Kennecott.

A. Under this agreement, Kennecott would be compensated for operating its 163 MW coal-fired plant at a high output level during heavy-load hours from March through October. The generation credit has a lower cost to customers than the purchase of market power to supply the Kennecott load. The term of the agreement is from March 1, 2005 through December 31, 2009.

Q. What information was provided to the Board of Directors in connection with the Kennecott generation credit agreement?

A. Included as Exhibit No.___(MRT-18C) is the Board presentation from its February 15, 2005 meeting regarding the decision to enter into the Kennecott generation credit agreement.

Q. Please describe the operating reserve agreement with US Mag.

A. This five-year agreement would allow the Company to purchase up to 95 MW of non-spin operating reserves from US Mag for 100 hours each year. US Mag's magnesium production facility has the operational capability to shut its load off for short periods of time (two hours or less) without physically affecting its process. By purchasing non-spinning reserve from US Mag, the Company would avoid holding these reserves on our higher cost power plants. The pricing terms are based on the Company being able to dispatch 95 MW from our higher cost plants when it is economical to do so.

Q. What information was provided to the Board of Directors in connection with the US Mag operating reserve agreement?

A. Included as Exhibit No.___(MRT-19C) is the Board presentation from its December 16, 2004 meeting regarding the decision to enter into the US Mag operating reserve agreement.

Q. Does this conclude your testimony?

A. Yes.