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

A. My name is Stan K. Watters. My business address is 825 NE Multnomah, Portland, Oregon, 97232. My present position is Senior Vice President of the Commercial and Trading Department. My position is part of PacifiCorp's regulated merchant function.

Qualifications

Q. Please describe your education and business experience.

A. I joined the Company in 1982 and I have held various positions in engineering, finance, and wholesale prior to my current position. In my position as Senior Vice President of Commercial and Trading, I am responsible for the Company's wholesale sales and trading functions including the economic dispatch of PacifiCorp's system resources. I graduated from Oregon State University in 1981 with a Bachelor of Science in Civil Engineering.

Summary of Rebuttal Testimony

Q. What issues will you be addressing in your rebuttal testimony?

A. My rebuttal testimony addresses the following issues raised by the testimony offered by CCS and UAE:

- UAE witnesses Anderson and Townsend propose an adjustment that would remove Currant Creek and West Valley from rate base, and replace it with a "proxy" plant calculated by reference to a fictional acceleration—by two years—of the in-service date of the Lake Side project. My testimony shows that the Company's Utah customers would be worse off under this proposal, if properly calculated to reflect the costs that would be associated with such an accelerated schedule for Lake Side. My testimony also rebuts the underlying contentions of Dr. Anderson by showing that (1) the Company's load growth forecasts for Utah during the relevant periods were reasonable, and (2) the Company's power resource strategy—which included reliance on wholesale markets, in part, to serve new load—was reasonable based on information known at the time. It is only through Dr. Anderson's hindsight knowledge of the Western energy crisis that the Company's strategy is drawn into question.

- CCS witness Falkenberg proposes a disallowance of approximately $7 million associated with the Company's decision not to terminate the West Valley lease. My testimony shows that the Company's decision was in the customers' interest, and that Mr. Falkenberg's adjustment is based upon a faulty analysis with invalid assumptions.
- Mr. Falkenberg also proposes to disallow the expenses associated with the Aquila hydro hedge secured by the Company. My testimony explains how financial hedges such as these benefit customers, and therefore the associated costs should be included in rates.

Substitution of Proxy Plant for Currant Creek, West Valley

Q. Please describe the adjustment you are addressing.

A. UAE witness Anderson claims that the Company failed "to move in a timely manner to meet the surging load growth in Utah" and argues that if the Company "had not forestalled its decisions and actions," it would have been unnecessary to renew the lease for West Valley and to build the Currant Creek project. Rather, according to Dr. Anderson, the Company "could have developed the Lake Side project or another similar resource" at an earlier date. For this "proxy resource," UAE witness Townsend assumes that the Lake Side project had been brought on line approximately two years earlier, in April 2005. Based on this fictional substitution, UAE calculates an adjustment of $16.4 million, comprising an expense reduction of $12.8 million, an increase in rate base of $80.1 million, and an increase in sales revenue of $7 million.

Q. What is your response to the proposed adjustment?

A. The premise upon which the adjustment is based—that the Company was slow to react to the load growth in Utah—is flawed. Moreover, the assumptions made by Mr. Townsend in calculating the adjustment are incorrect. If the adjustment is calculated correctly, the Company's requested revenue requirement in this case would be $11.8 million higher rather than the $16.4 million reduction calculated by Mr. Townsend.

Q. Please explain why Mr. Townsend's calculations are incorrect.

A. There are a number of fundamental issues with Mr. Townsend's proposed scenario of having the Lake Side resource available by the summer of 2005 instead of the planned summer of 2007. It is not simply a matter of advancing the entire Lake Side project schedule and costs forward by two years, as Mr. Townsend assumes. His approach ignores a number of circumstances which would have existed during the time periods relevant to an assumed summer 2005 in-service date for Lake Side. Calculating the costs of the Lake Side project under the circumstances that would have existed at the time corresponding to a summer 2005 in-service date produces a far different result.

Q. Please explain how the Company performed its analysis.

A. We used the capital and operating costs (excluding fuel costs) of the Lake Side project assuming a summer 2005 in-service date. In working the schedule backward to determine the date when equipment would have been purchased, we assumed six months for an RFP process, six months to obtain a CCN approval, and a 24-month construction period.

Q. Please describe the circumstances that would have existed during the time periods corresponding to a summer 2005 in-service date for Lake Side.

A. First, the point in time in which prospective developers would have had to identify a site, specifically the Vineyard site, adjacent to and owned by Geneva Steel, would have been at a time when Geneva Steel was still actively working at being a going concern. Simply, the Vineyard site, with all the elements necessary for development for a large generation resource (land, water, emission credits, zoning) would not have been available at the time when the fictional resource would have been developed by potential bidders to an RFP. Geneva Steel did not file for bankruptcy until January 2002 and did not publicly offer to sell its land, water, and emissions credits assets until January 22, 2003. Furthermore, the bankruptcy court did not allow for the disposition of these assets until mid 2004. In summary, the site would not have existed to develop the Lake Side facility for a commercial date to meet the summer peak of 2005.

Second, the market for equipment and power plant development was much different during the 1999-2002 time frame, which is the period when developers would have had to prepare bids corresponding to the summer 2005 in-service date for Lake Side assumed by Mr. Townsend. At that time, developers and equipment suppliers simply did not know that the demand would slow and that a surplus was just around the corner. At that time, equipment prices were significantly higher, lead times were much longer, contractors secured high margins (or faced financial problems), and skilled labor was at a premium. In contrast, PacifiCorp's timing for securing the 2007 Lake Side resource was fortunate in that it occurred (1) after the resource boom, at a time when surplus equipment was available and equipment prices were depressed, and (2) after the Geneva Steel assets were available.

Q. What does the Company's analysis show?

A. Exhibit UP&L___ (SKW-1R) sets forth the results of the Company's analysis, which was provided in response to UAE Data Request Nos. 6.1 and 6.2. As described above, accepting Mr. Townsend's assumption that a fictional summer 2005 resource should be substituted for West Valley and Currant Creek would produce an increase of $11.8 million in the Company's requested revenue requirement in this proceeding. Exhibit UP&L___ (SKW-1R) presents all the supporting calculations, as well as a description of the underlying assumptions in the Company's analysis. It should also be noted that the fictional UAE "proxy plant" alternative benefits from changes in allocation factors used for seasonal versus year-round resources.

Q. Please explain how the difference in allocation factors affects the analysis.

A. For the subject test year, the plants that UAE would "remove" under its proposed adjustment – West Valley and Phase I of Currant Creek – are both Seasonal resources under the MSP Revised Protocol, and thus a higher percentage of their costs are allocated to Utah given Utah's higher loads during the season in which the plants are relied upon most heavily. The fictional "proxy plant," on the other hand, is a combined cycle combustion turbine which is a year-round resource and a lower percentage of its costs is allocated to Utah. This difference in allocation factors, which is quite apparent from Mr. Townsend's exhibit, UAE Exhibit 2.1 (TNT-1) in the column labeled "Factor %," contributes to the seeming cost advantage under UAE's incorrect calculation of the "proxy plant" comparison.

Q. What do you conclude from the Company's analysis of the UAE "proxy plant" alternative?

A. Fundamentally, as discussed below, we do not agree that any adjustment at all is warranted, given that the Company's actions with respect to resource acquisitions to serve Utah load were prudent. The reasonableness of the Company's actions is confirmed by the analysis shown in Exhibit UP&L___ (SWK-1R). Had the Company embarked down the path suggested by UAE's adjustment, our costs would have been materially higher.

Q. Please explain why the premise upon which the adjustment is based is flawed.

A. As the basis for UAE's adjustment, Dr. Anderson criticizes the Company's planning efforts during the late 1990s. Specifically, he claims that (1) the Company's power resource strategy relied too heavily on the wholesale markets, (2) the Company did not anticipate and plan for load growth in Utah and incorrectly evaluated the risks of competition, and (3) concerns about the inter-jurisdictional cost allocation issue caused the Company to delay the acquisition of new generation. I will address each of these claims.

Q. Please discuss the Company's reliance on wholesale markets for planning purposes.

A. During the periods leading up to the acquisition of Gadsby, West Valley and Currant Creek, Dr. Anderson criticizes the Company for relying on the wholesale markets rather than building or acquiring new resources. He attributes this reluctance to build to a "fear of deregulation" and a response to uncertainty regarding interjurisdictional cost allocations. In fact, the Company was taking advantage of the opportunities provided by the wholesale markets during this period. Throughout most of the late 1990s, power was available on the wholesale market at prices that were much lower than would have been produced by the Company pursuing a build option. RAMPP-4, for example, concluded that PacifiCorp did not need to make any resource acquisitions and that the Company instead should take advantage of the low-cost market power to meet its requirements. The wholesale markets during this period were marked by strong competition, with very heavy sales and purchasing volumes. With the number of new entrants into the wholesale markets, the expansion of new markets and the establishment of new trading hubs, there were many participants and market prices declined to the lowest levels in history and resulting margins on sales became extremely narrow. The market was thought to be overbuilt, and the surplus in the western region was expected to continue for several years. In

RAMPP-4, the Company projected the price of market based power to be approximately $25 per MWh (in real 1996 dollars) in 2001. Short-term firm power was viewed as a cheaper alternative to simple cycle combustion turbine (SCCT) and CCCT additions.

As Dr. Anderson notes in his testimony, the Company made the decision in 1999 to sell its ownership the Centralia coal plant, given that wholesale price forecasts at the time showed that the output could reasonably be replaced with market purchases. That the Company was able to obtain the necessary regulatory approvals to sell Centralia – including the approval from this Commission – is evidence of the prevailing view at the time that wholesale purchases could reasonably be relied upon rather than utility-owned generation for serving load requirements.

All this changed, of course, when the Western energy crisis began in May 2000. The reliance on wholesale markets that seemed so reasonable based on historical experience had to be reconsidered. Although Dr. Anderson claims in his testimony that he is not being a "Monday morning quarterback" in his criticism of the Company's chosen course of resource development, he clearly is engaging in a retrospective evaluation with the benefit of perfect hindsight. Prior to the Western energy crisis of 2000-2001, it was entirely appropriate for the Company to "buy" rather than procure a long-term resource based on the cost to "build," and Dr. Anderson would have been one of the first to object had the Company embarked on such a resource acquisition program during the late 1990s. Given the prices prevailing in the wholesale markets, it simply didn't make sense. With the benefit of knowing now about (1) how high wholesale prices can reach and (2) how the uncertainties associated with deregulation during the late 1990s actually played out, it is easy for Dr. Anderson to formulate his after-the-fact attacks on the Company's resource development strategy. Based on the circumstances known to the Company at the time, however—which is the proper test—the Company's actions were reasonable and prudent, and no basis for a disallowance has been shown.

Q. How do you respond to Dr. Anderson's claims regarding unanticipated load growth in Utah?

A. Once again, Dr. Anderson operates with the benefit of knowing how some of the uncertainties that existed at the time actually played out. A key assumption included by the Company in RAMPP-5, for example, was the loss of 10 percent of our retail load to new competitors. At the time, this was a reasonable assumption, given that in the late 1990s it was widely believed that the electric utility industry was marching inexorably toward retail competition. For example, during this period Dr. Anderson was advocating full retail access in Utah for large customers no later than April 1998 and for all customers no later than January 1999 in order to prevent Utah from "becoming an island of regulation in a deregulated market" given the "[g]rowing number of states adopting restructuring plans aimed at introducing competition in the electric market." Now that it is apparent the retail competition clamored for and predicted by the industrial customers has failed to materialize, the Company is being criticized by these same customers, apparently for failing to accurately predict how unsuccessful they would be in achieving their objectives. Similarly, the assumed sale of the Company's service territory in California did not materialize. These two factors alone have a considerable impact on whether or not load/resource balance would be achieved.

While Dr. Anderson is highly critical of the Company's forecast of Utah load growth, for the most part the Company's forecasts of energy usage in Utah were *higher* than what actually occurred, as indicated in Table 1 below.

Average Annual Growth Rates	Total Company	Utah
RAMPP-3 1993-2003	2.40%	3.07%
Actual 1993-2003	1.59%	3.51%
RAMPP-4 1996-2003	2.17%	2.77%
Actual 1996-2003	1.26%	2.49%
RAMPP-5 1998-2003	2.11%	3.29%
Actual 1998-2003	1.19%	2.66%

Q. How do you respond to Dr. Anderson's criticism of the Company's forecasting of peak loads in Utah during this period?

A. The Company's forecasting of peak loads was reasonable, based on information available at the time. What was occurring in Utah during this period, however, was a dramatic departure from prior experience with respect to air conditioning loads. The population growth in Utah during this period was accompanied by increased use of central air conditioning (rather than swamp coolers) for residential loads, which apparently is attributable to the preference of new Utah residents to install central air conditioning and their ability to pay for it. In addition, the drop in mortgage interest rates during this period enabled substantial refinancing activity that resulted in additional consumer spending on appliances and larger homes. These trends were new developments that would have been difficult to predict based on historical information at the time.

Q. Is Dr. Anderson correct that concerns about cost recovery caused the Company to delay acquisition of new generating resources?

A. No. It was entirely appropriate for the Company to express its concern in various proceedings about resource planning in the face of uncertain cost recovery given the lack of agreement about inter-jurisdictional cost allocations. However, there is absolutely no evidence that these uncertainties led to the Company actually delaying necessary resource acquisitions. Gadsby was acquired, for example, even though the cost allocation issue had not been resolved. As described above, new generation was generally not acquired because the economics at the time would not justify it, not because of uncertainties regarding cost recovery. Once the economic analysis changed, the Company moved with all due speed to acquire the necessary resources, regardless of any uncertainty regarding cost recovery.

Q. What do you conclude regarding UAE's proposed adjustment to exclude West Valley and Currant Creek in favor of a "proxy" resource?

A. No basis for making an adjustment has been shown. The Company's resource development strategy has been reasonable and prudent when evaluated under the circumstances and information known at the time, and the evidentiary foundation for a disallowance is lacking. If an adjustment were to be made as proposed by Dr. Anderson and Mr. Townsend, the result would be an increase in the requested revenue requirement in this proceeding, a result that confirms the reasonableness of the Company's resource development strategy.

West Valley Disallowance

Q. Please describe 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 ("West Valley Project"). 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. Mr. Falkenberg is critical of the Company's affiliate relationship with the owner of West Valley. How was the West Valley lease originally selected?

A. In September 2001, the Company 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. The RFP generated 52 proposals from 27 different parties. PacifiCorp took a number of 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 terms of the West Valley lease.

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 for reliability purposes. 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. PacifiCorp has two options (vesting in years three and six) to (1) terminate the lease, (2) continue with the lease under its terms and conditions as written, or (3) purchase the West Valley Project. 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 volatility of the power markets in recent years.

Q. Please describe PacifiCorp's actions with respect to the first termination option under the Lease.

A. PacifiCorp issued a notice of termination and subsequently rescinded it. 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. Such a notice must be confirmed by June 30, 2007 if the Company determines that it desires to continue with the lease agreement.

Q. What process did PacifiCorp follow before deciding to retain its lease option on the West Valley plant for an additional three years?

A. PacifiCorp issued RFP 2004-X to seek potential resources to replace the West Valley Lease. The Company solicited resource alternatives that would be available by June 1, 2005 for terms of: (1) three-years, or (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 Btu/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. You mentioned that the Company determined termination of the lease can lead to a higher risk of customer outages on both an amount basis and an exposure basis. Would you please describe that further?

A. Yes. The commercial organization for which I am responsible notified the

Company's transmission function that a network resource (West Valley) may be removed from being under our control by the summer of 2005. The transmission function studied the reliability impacts and informed us that the amount of load loss at risk would increase more than three fold, from 60 MW to 200 MW. In addition, we were informed that the exposure of such load loss would double from 100 hours per year to 200 hours per year. The customers primarily affected by this increased risk of outage are located in Southwest Salt Lake and are connected to the Oquirrh 138 kV bus. This bus serves a large portion of the Kennecott Copper load, portions of Tooele, West Jordan, South Jordan, Riverton, and Herriman. Upon making our final decision to retain the West Valley lease for at least three years, we communicated our reasoning behind the decision, including the increased risk of customer outages if the resource was removed as a network resource, to certain stakeholders including large industrial representatives.

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 Integrated Resource Plan (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 IRP assumes the lease will be terminated to be able to study other more economic resource alternatives such as the emerging intercooled aero combustion turbine design and combined cycle combustion turbine design. For example, the General Electric

LMS-100 natural gas turbines are expected to have heat rates lower than General Electric's LM-6000. As the Company implements 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.

Q. Please describe the adjustment Mr. Falkenberg is proposing with respect to the West Valley Lease.

A. CCS witness Falkenberg proposes a disallowance of approximately $7 million associated with the Company's decision not to terminate the West Valley lease. He claims that the Company should have given notice well in advance of June 1, 2004 and, further, should have issued an RFP much earlier than its RFP 2004-X process. Specifically, Mr. Falkenberg believes the Company should have considered replacement of West Valley in conjunction with RFP 2003-A, and he calculates a disallowance based on the Company selecting a particular bid in that process rather than continuing under the West Valley lease.

Q. Do you agree with Mr. Falkenberg that an adjustment is appropriate?

A. No. The Company's course of action with respect to its decision regarding the first termination option under the West Valley Lease was entirely reasonable and prudent. The Company's exercised its option to terminate the lease in a timely manner. After doing so, the Company conducted RFP 2004-X to determine if there were resources available that could replace the West Valley Lease at a lower cost to customers. As described above, the Company secured the services of an independent consultant, Lands Energy, to assist in the evaluation of responses to RFP 2004-X and in the Company's analysis of whether to continue under the

West Valley Lease. Our analysis concluded that the West Valley project was the best option, and we therefore rescinded the lease termination. Given the thorough process and analysis undertaken by the Company in connection with this resource decision, there is no basis for disallowing any costs associated with the West Valley lease.

Q. What about Mr. Falkenberg's claim that the RFP process should have been commenced earlier to a provide a "realistic option for the construction of new capacity"?

A. Mr. Falkenberg fails to acknowledge that the Company was informed by the results of the earlier RFP 2003-A process as it considered the West Valley lease. Contrary to Mr. Falkenberg's incorrect assertion, the West Valley lease is not a long-term resource. Given the termination options included in the West Valley Lease, it is effectively a 3-year resource with an option to extend. Starting RFP 2004-X earlier was not necessary in order to solicit 3-year alternatives since PacifiCorp's RFP 2003-A included a bid category that solicited for 3-year resources intended to meet our growing summer demand. As has been reported by Navigant Consulting Inc. to the Commission, the Company did not receive any viable short-term alternatives. Notwithstanding this, the Company issued RFP 2004-X to again attempt to solicit alternatives from the market.

Q. Do you agree with the manner in which Mr. Falkenberg calculated his adjustment?

A. No. He calculated his adjustment on the basis of a particular bid in the Company's RFP 2003-A, Bid No. 198. We performed an analysis under the assumptions he specified—using his proxy bid from RFP 2003-A rather than West Valley—and our analysis shows that customers would be worse off under that scenario. Exhibit UP&L___ (SKW-2R) summarizes this analysis.

Q. What does Exhibit UP&L___ (SKW-2R) show?

A. Exhibit UP&L___ (SKW-2R) compares (1) the proxy bid selected by Mr. Falkenberg, which is a simple cycle combustion turbine using 4 LM6000 units, with (2) the West Valley Lease for 3 years followed by a combined cycle combustion turbine (CCCT) for the remaining term. This second scenario (West Valley for 3 years and then a CCCT) is consistent with the assumptions used to develop the draft action plan of the IRP to be published in 2005. This comparison shows that the proxy resource used as the basis for Mr. Falkenberg's adjustment would actually *increase* costs for customers. Specifically, Exhibit UP&L___ (SKW-2R) shows a net resource value for his proxy resource that is $134.9 million less than the West Valley/CCCT choice.

Q. What do you conclude from this analysis?

A. It confirms that a disallowance is unwarranted. Not only has Mr. Falkenberg failed to show that the Company in any way acted imprudently with respect to the West Valley lease termination option, the resource he has chosen as the basis to calculate his disallowance would actually *increase* costs for customers. If Mr. Falkenberg is correct that an adjustment is warranted, the Company should receive a premium, rather than a disallowance, as a result of its decision to continue with the West Valley Lease.

Q. How do you respond to Mr. Falkenberg's argument that the Company assigns too much value to the ability of West Valley to provide reserves?

A. Mr. Falkenberg's point is that West Valley historically has been seldom needed for purposes of carrying reserves. In support of this contention, he cites the Company's response to DPU Data Request 9.7a, which shows that, on average, West Valley had only 10 mW of capacity available for spinning reserve per month in 2004. Irrespective of West Valley's historical performance, on a going-forward basis, West Valley will have the capability of carrying reserves in greater amounts. As explained in Mr. Widmer's testimony, when the units were new, they initially were dispatched at a near full capacity to meet load. As the Company's schedulers gain more experience with the units, the actual dispatch of the CT units is trending toward increased frequency of dispatch at 20 MW in order to allocate more operating reserves to the units. Given these circumstances, we believe we have assigned an appropriate value to West Valley's ability to carry reserves.

Regulatory Treatment of Financial Hedges

Q. What is Mr. Falkenberg proposing with respect to financial hedges?

A. The Company pays $1.75 million annually to Aquila to hedge its risks associated with hydro conditions. During years in which water conditions are poor, the Company receives a payment from Aquila. When actual hydro energy exceeds a certain level, the Company makes payments to Aquila. The Company proposed a balancing account to pass through the hydro costs and revenues to customers. Mr. Falkenberg's adjustment would disallow the $1.75 million annual premium, and no balancing account would be established.

Q. Do you agree with his approach with respect to financial hedges?

A. No. His opposition to hydro hedges seems to be based on three arguments: (1) ratepayers do not receive any benefits under the GRID model, (2) expected costs of the hedge exceed expected benefits, and (3) the annual premium may not be a reasonable price.

Q. How do customers benefit from the Aquila hydro hedge?

A. Customers benefit in two ways. First, the Aquila hydro hedge provides some protection for customers from the rate impacts associated with poor hydro conditions and the high power costs that are associated with poor hydro conditions. During the 2000-2001 Western energy crisis, for example, the Company experienced the second worst hydro conditions in the history of recordkeeping in the Northwest. These poor hydro conditions contributed to the extraordinary power costs that the Company deferred and ultimately recovered, at least in part, from Utah customers in Docket Nos. 01-035-29 and 05-035-36. In circumstances such as this, the Aquila hydro hedge would provide some cushion against the power cost impacts associated with poor hydro conditions. As discussed below, financial hedges provide only a partial solution with respect to power cost impacts.

Second, financial hedges such as the Aquila hydro hedge reduce the volatility of the Company's power cost expenses which, in turn, reduces the volatility of the Company's earnings. The reduced earnings volatility will be viewed positively by the financial community, which ultimately will result in lower borrowing costs for the Company

Q. How can these benefits be captured in rates?

A. We agree with Mr. Falkenberg that the power cost benefits of financial hedges cannot easily be captured in rates by the GRID model, and we have taken steps to address that issue. As Mr. Widmer describes in his testimony, the Company is proposing a balancing account that would permit any benefits provided by Aquila, or payments by the Company to Aquila, to be passed through to customers. Of course, these are not the only benefits associated with financial hedges. As described above, the reduced earnings volatility will ultimately result in lower borrowing costs for the Company. These lower borrowing costs will be flowed through to customers as the cost of capital is adjusted in future rate proceedings to reflect the improved financial profile of the Company.

Q. Please explain why financial hedges provide only a partial solution for power cost impacts.

A. The Company faces far more exposure to power cost variability than can be covered through financial hedges. Given the higher prices that are prevailing in the wholesale markets, the impacts associated with normal variation in loads and resources are much greater than historical experience. For example, the replacement power necessary in the event of a thermal outage historically was not far out of line with the Company's embedded power costs, and the impact of an extended outage was usually not significant. In today's wholesale markets, however, the difference between the costs of operating a thermal unit and the costs of replacing that unit's output on the market in the event of that unit's unavailability can be quite large. Similarly, the normalized level of wholesale power costs built into rates in rate proceedings can be far exceeded in the event of gas price spikes, price excursions in the wholesale markets, or poor hydro conditions region-wide. This "gap" between normalized power costs and actual power costs cannot be covered with financial hedges. Moreover, the exposure to power cost variability is not symmetrical.

Q. Please explain.

A. In the case of hydro conditions, for example, the exposure is not symmetrical because the positive impacts in good hydro years are far outweighed by the negative impacts in poor hydro years, so that the Company fares badly when power costs are normalized in general rate cases. The impacts simply do not "even out" over time. In good hydro years, power prices will typically be slightly lower due to the increased supply provided by hydro output. Thus, the additional revenue which the Company collects from additional hydro generation is valued at lower prices. The problem is compounded by the time of day in which the additional hydro is typically available, which is during light load hours when prices are even lower. In contrast, power price increases during bad hydro years can be substantial, and thus the costs paid by the Company to replace the lost hydro generation can be significant. Stated simply, power prices will not go down as much in good hydro years as they will go up in bad hydro years. The same is true of wholesale power costs generally – they are capable of dramatic and unpredictable ***increases***, but will not display the same range on the ***downside***. Because of this asymmetrical exposure, a power cost adjustment mechanism is necessary to give the Company a reasonable opportunity to be made whole over time.

Q. Do you agree that expected costs of the Aquila hedge exceed expected benefits?

A. No. In making that statement, Mr. Falkenberg defines benefits very narrowly. Under his narrow definition, it is not surprising that the premium costs may exceed his definition of benefits. That is the nature of an insurance-type product: in exchange for Aquila bearing the risks associated with variability in hydro conditions, Aquila is compensated for that risk through the premiums it charges. Mr. Falkenberg's definition of expected benefits does not include the financial benefits resulting from reduced volatility of power costs, as described above. When these are considered, the expected benefits exceed the expected costs, and customers are better off when the Company enters into such financial hedges. In the case of the Aquila hedge, as referenced in Mr. Widmer's testimony, the benefits (payments to PacifiCorp) have exceeded the costs (payments to Aquila) even without considering the reduction in earnings volatility.

Q. Is the annual premium reasonable in amount?

A. Yes. CCS Exhibit 6.6C, included with Mr. Falkenberg's testimony, is the financial analysis prepared by the Company before it entered into the Aquila hydro hedge. That analysis demonstrates that the $1.75 million figure is reasonable for the coverage provided.

Q. Why should the costs associated with financial hedges be included in rates?

A. Customers clearly benefit from such hedges and, under the Company's proposal, these benefits are flowed through in rates. Given that customers receive the benefits, it is reasonable that rates reflect the costs as well. Moreover, excluding such costs from rates would send a strong signal to the Company that such financial hedging transactions are not encouraged. We believe we are acting in the best interests of customers in entering such transactions. If the Commission believes otherwise—and disallowing these costs in rates would tend to send that signal—it would probably be appropriate for the Company to revisit its policies with respect to financial hedges.

Q. Does this conclude your rebuttal testimony, Mr. Watters?

A. Yes.