BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR APPROVAL OF A GENERAL RATE INCREASE OF $232.4 MILLION PER YEAR OR 13.7 PERCENT	)))))))	**DOCKET NO. 10-035-124**

PUBLIC SURREBUTTAL TESTIMONY AND EXHIBITS OF

MARK T. WIDMER

ON BEHALF OF

UTAH INDUSTRIAL ENERGY CONSUMERS (UIEC)

July 19, 2011

Q. ARE YOU THE SAME MARK T. WIDMER THAT PREVIOUSLY PROVIDED TESTIMONY IN THIS PROCEEDING?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony rebuts various parts of the testimony of PacifiCorp witnesses Mr. Duvall, Mr. Apperson and Mr. Bird related to issues which are still being contested by the Company.

SURREBUTTAL UPDATE AND GENERAL COMMENTS

Q. HAVE YOU REVIEWED THE COMPANY'S NPC REBUTTAL UPDATE?

A. Yes. However, my review was limited due to the short period of time available before surrebuttal testimony was due.

Q. DO YOU SUPPORT THE COMPANY'S UPDATES?

A. I am generally opposed to updates with the exception of corrections, new or revised contracts and known and measurable changes. Other updates that the Company springs on Parties at such a late stage of the regulatory process, burdens an already short period for review. In keeping with that, I support many but not all of the Company's updates. I support adjustments for corrections, known and measureable adjustments for updated contracts, revised contracts, and new contracts including new STF transactions buried within the Official Forward Price Curve (OFPC) update, the Bear River adjustments, which were adopted by the Company and the hydro outage period update because this change was adopted by the Company during the discovery process. The specific adjustments I do not support are the OFPC update, update to start-up O&M, the portion of coal costs tied to index changes, and the Utah QF extension. I do not support the OFPC update because it is not timely, is more complex than other adjustments because it affects numerous inputs and components to NPC and does not fit a true definition of known and measureable like new or revised contracts do. Correspondingly, I do not support the portion of the coal cost update tied to index adjustments because it is similar in nature to the OFPC adjustment. I do not support the start-up O&M update because the adjustment is not timely and lastly, I do not support extending QF contracts without a signed contract because they are not known and measurable.

Q. ON PAGE 10 OF MR. DUVALL'S REBUTTAL TESTIMONY HE STATES: "WHILE THE COMMISSION EXPRESSLY ADOPTED THE EBA TO ADDRESS THE GROWING DISPARITY BETWEEN FORECAST AND ACTUAL NPC, THE VOLUME AND MAGNITUDE OF THE NPC ADJUSTMENTS IN THIS CASE THREATEN TO INCREASE THAT DISPARITY AND WORK AT CROSS-PURPOSES WITH THE EBA. DO YOU HAVE ANY COMMENTS REGARDING THE DIFFERENCE BETWEEN ACTUAL AND NORMALIZED NPC DISCUSSED BY MR. DUVALL?

A. Yes. While the difference between actual and normalized NPC is a comparison, it is not a perfect comparison because several of the components of net power costs are normalized over long-term periods. For example, hydro conditions are normalized over a minimum of 30 years and in many cases significantly more. Since hydro generation has a zero generation cost, differences between actual and normalized NPC can be very large for individual years or a period of years, but it does not necessarily mean there is a recovery problem. It could just be a timing issue. For example, over a 30 year period a river could have 15 poor hydro years and 15 good hydro years, which over the 30 year period are equivalent to normalized hydro generation in rates. Of course, in many instances it is more complicated than just differences between actual and normalized hydro generation. The whole point here is that differences between actual and normalized NPC require a more detailed analysis before it can be determined if there is a recovery problem.

Q. GIVEN MR. DUVALL'S COMMENTS ON THE NUMBER OF ADJUSTMENTS PROPOSED IN THIS CASE, SHOULD THE COMMISSION BE CONCERNED ?

A. No. It should not matter if there is one or 40 adjustments. If there are input errors within the model, logic flaws with the model or inappropriate modeling assumptions, they should be corrected. The Company has the burden of proof to support its request for a rate increase. If the Company can refute proposed adjustments with verifiable evidence the adjustments should be rejected by the Commission. If the Company cannot refute adjustments proposed by the Parties with verifiable evidence, they do not deserve recovery of the costs.

Q. ON PAGE 12 OF MR. DUVALL'S TESTIMONY HE STATED THAT "NPC MODELING ADJUSTMENTS SUCH AS THOSE PROPOSED IN THIS CASE WHICH SIGNIFICANTLY DECREASE THE GRID RESULTS REDUCE THE OVERALL ACCURACY OF THE NPC FORECAST." IS THIS COMMENT CONSISTENT WITH THE COMPANY'S ACTIONS?

A. No. In many cases the Company has vigorously contested many of these adjustments only to later come back and settle for a lower result than the Company proposed. The most recent example would be Wyoming Docket No. 20000-384-ER-10, where the Company filed rebuttal testimony which accepted two out of 40 proposed NPC adjustments only to later agree to a settlement that allowed recovery of roughly 66% of the outstanding adjustments.

Q. IS THE TESTIMONY FILED IN OREGON A VALID BENCHMARK TO THE EVALUATION OF THE COMPANY'S BENCHMARK IN THIS CASE AS MR. DUVALL SUGGESTS?

A. No. The test year is different and that alone makes the comparison invalid. Further, there has not been a completed review of the Company's Oregon filing. In my 25 plus years in the utility regulatory area I cannot recall the Company being granted 100%

recovery of NPC in a general rate case proceeding. In fact, stipulations adopting recovery of less than 100% of the requested cost recovery have been more of the norm in recent years. As such, Mr. Duvall's Oregon testimony on forecast NPC is not a valid benchmark for the appropriate level of NPC in this docket.

Q. BESIDES USING AUTHORIZED NPC TO DETERMINE BASE RETAIL RATES, WILL THE AUTHORIZED NPC ALSO BE USED TO CALCULATE THE ENERGY BALANCING ACCOUNT (EBA) BASE FOR RECOVERY OF DEFERRED COSTS?

A. Yes. The monthly EBA base is equal to the Utah allocated share of the monthly sum of authorized NPC minus swap transactions, plus wholesale wheeling revenues recorded to FERC account 456.1, divided by monthly Utah base MWh.

Q. DO YOU HAVE A RECOMMENDATION FOR THE FINAL DETERMINATION OF AUTHORIZED NPC?

A. Yes. The proposed value of various adjustments can be impacted by the order of the adjustment relative to other adjustments and the final composition of Commission adopted adjustments. Therefore, I recommend that the Commission require a final GRID run that incorporates only the Commission adopted adjustments to determine the final authorized NPC.

SPECIFIC UPDATES

Adjustment 1. **<u>CAL ISO WHEELING AND SERVICE FEES</u>**

Q. MR. DUVALL STATES ON PAGE 48 OF HIS REBUTTAL TESTIMONY THAT YOU RECOMMEND REMOVAL OF THE CAL ISO WHEELING EXPENSES AND FEES. IS THAT AN ACCURATE STATEMENT?

A. No. As explained in my direct filed testimony, my adjustment imputes a conservative benefit of the Cal ISO transactions that is merely equal to the incremental cost of the Cal ISO wheeling expenses and fees that are incurred to facilitate wholesale transactions with Cal ISO.

Q. DO YOU AGREE WITH MR. DUVALL THAT THE COMPANY WILL ENTER CAL ISO TRANSACTIONS DURING THE RATE EFFECTIVE PERIOD?

A. Yes, but Mr. Duvall misses the point. The test year only includes the Cal ISO wheeling expenses and fees. It does not include the higher margin / lower cost Cal ISO wholesale transactions, which are the sole justification for incurring the incremental Cal ISO wheeling expenses and fees. If the Commission allows the recovery of the Cal ISO wheeling expenses and fees in the GRC without my proposed adjustment, the Company will recover 100% of the Cal ISO wheeling expenses and fees and only 70% of the benefits of the Cal ISO transactions through the EBA. Therefore, the Company's proposed NPC includes a mismatch. The underlying revenues should be included in base retail rates.

Q. IS MR. DUVALL CORRECT WHEN HE CONTRADICTS YOUR STATEMENT THAT THE COMPANY EXECUTES TRANSACTIONS WITH THE CAL ISO TO SERVE LOAD, NOT TO EARN A MARGIN?

A. Of course not. The Company makes both wholesale sales and purchases with the Cal ISO. The Company makes wholesale sales in the markets where it gets the highest price or margin above its cost. If the Company does not earn a margin above its variable costs it should not make the sale. The Company also makes wholesale purchases at the lowest cost available to serve wholesale and retail load obligations or to displace higher cost resources on its system. The lower the cost of the purchases, the higher the margin the Company earns from overall system operations. My position is supported by the Company's response to WIEC 6.11 from Wyoming Docket No. 20000-384-ER-10, which states that the Company executes the most economic transactions available. The Company's complete answer to this response is shown on page 12 of my direct filed testimony.

Q. ARE YOU RECOMMENDING THAT THE COMPANY ELIMINATE CAL ISO AS A COUNTER PARTY?

A. No and if the Company were to do so it would be imprudent on their part to not enter the most economic transactions available.

Q. IS MR. DUVALL CORRECT WHEN HE STATES THAT REMOVING THE CAL ISO AS A COUNTER PARTY WOULD LIMIT THE COMPANY'S ABILITY TO FULLY UTILIZE THE MARKET AND CAUSE NPC TO INCREASE?

A. While it is true from the perspective of actual operations, it is not true for this general rate case. The Company's proposed NPC does not model the acquired Cal ISO transmission capacity and does not include any executed CAL ISO wholesale transactions. Wholesale balancing transactions executed by GRID are done so with only the existing transmission system and therefore, do not provide justification for the inclusion of the Cal ISO expenses unless the benefit derived from the incurrence of those expenses is also included.

Q. DID MR. DUVALL PRESENT ANY NEW INFORMATION TO SUPPORT HIS RECOMMENDATION?

A. No. Mr. Duvall still has not presented any evidence to support his modeling of the Cal ISO wheeling expenses and fees without the inclusion of the corresponding benefit of the wholesale sales and purchase transactions.

Adjustment 2. **<u>RESERVE SHUTDOWNS</u>**

Q. IS YOUR RESERVE SHUTDOWN ADJUSTMENT PREDICATED ON A BELIEF THAT PACIFICORP INCORRECTLY CALCULATES THE FORCED OUTAGE RATES?

A. No. My issue is with the GRID model's utilization of those outage rates. Put another way, the GRID model has a flaw if the intent of the model was to use PacifiCorp's calculated forced outage rates. As previously stated, the Company's forced outage rates are calculated after reserve shutdowns, while GRID assumes that the outage rates are calculated prior to reserve shutdowns. As demonstrated in Exhibit___(MTW-2) and Exhibit___(MTW-3) of my direct testimony, this flaw causes the overstatement of generation lost due to forced outages.

Q. MR. DUVALL STATES THAT EXHIBIT___(MTW-2) IS NOT ILLUSTRATIVE OF HOW GRID FUNCTIONS BECAUSE THE ANALYSIS ASSUMES THAT THE GRID MODEL WILL IDENTICALLY PLACE THE FACILITY ON RESERVE SHUTDOWN IN THE SAME MANNER IN WHICH IT OCCURRED IN ACTUAL OPERATIONS. IS THAT A RELEVANT ISSUE?

A. No. The assumption used in my exhibits is merely a simplifying assumption that is used to isolate the inconsistent manner in which GRID uses PacifiCorp's forced outage rates. If GRID's utilization of PacifiCorp's forced outage rates was consistent, the results of my workaround included in Exhibits MTW-2 and MTW-3 would not have produced the same level of lost generation as shown in my PacifiCorp calculation example in Exhibit___ (MTW-2).

Q. DID MR. DUVALL'S REBUTTAL PROVIDE ANY ANALYTICAL INFORMATION TO REFUTE EXHIBIT___(MTW-2) AND EXHIBIT___(MTW-3).

A. No. While Mr. Duvall has made various claims he has not presented any analytical information to refute my exhibits, their demonstration of the problem, and the reasonableness of my proposed workaround. As they say, the proof is in the pudding.

Q. ARE OTHER WORKAROUNDS USED IN GRID?

A. Yes. Workarounds have not been uncommon for GRID. For example, the Company has adopted thermal plant screens as a workaround to correct GRID commitment logic flaws. The Commission should also adopt my proposed workaround to solve GRID's inconsistent utilization of forced outage rates.

Adjustment 3. **<u>GADSBY 4, 5, AND 6</u>**

Q. MR. DUVALL'S REBUTTAL TESTIMONY STATES THAT WHILE IT IS TRUE THAT A MUST RUN SETTING FORCES GADSBY UNITS 4, 5, AND 6 TO OPERATE IN ALL HOURS, THE MUST RUN SETTING ENSURES THAT THESE GAS UNITS ARE COMMITTED AND ABLE TO CARRY RESERVES AS IS OFTEN DONE IN REAL TIME OPERATIONS. DO YOU AGREE THAT TREATING UNITS AS MUST RUN PRODUCES RESULTS CONSISTENT WITH ACTUAL OPERATIONS?

A. No. Actual 2010 operation data for these generation units does not corroborate Mr. Duvall's statement. In fact, the data shows that roughly one-half of the time the Gadsby units didn't carry any reserves and therefore, were not committed. Gadsby 4 only carried spinning reserves for 4,471 hours and carried non-spin reserves during 165 other hours that it was not carrying spinning reserves and in total carried reserves for approximately 53% of actual annual hours. Gadsby 5 only carried spinning reserves for 4,256 hours and carried non-spin reserves during 140 other hours that it was not carrying spinning reserves and in total carried reserves for approximately 50% of actual annual hours. Gadsby 6 only carried spinning reserves for 4,344 hours and carried non-spin reserves during 155 other hours that it was not carrying spinning reserves and in total carried reserves for approximately 50% of actual annual hours.

Q. HAS THE NUMBER OF HOURS THAT GADSBY 4, 5, AND 6 CARRIED RESERVES DURING THE FIRST SIX MONTHS OF 2011 INCREASED FROM 2010?

A. No. The number of hours that these units carried reserves decreased significantly. During the first six months of 2011, Gadsby units 4, 5 and 6 carried reserves approximately 34%, 32% and 33%, of total hours, respectively. By no stretch of the imagination does this kind of actual operation provide justification for assigning a must run status to these units so they can carry reserves for 100% of the annual hours modeled in GRID. For this reason, the Commission should adopt my recommendation to eliminate the must run status for Gadby units 4, 5, and 6.

Adjustment 4. **<u>MORGAN STANLEY CALLS</u>**

Q. SINCE FILING YOUR DIRECT TESTIMONY HAVE YOU LEARNED MORE ABOUT PACIFICORP'S REASONING FOR ENTERING THE MORGAN STANLEY CALL OPTION CONTRACTS?

A. Yes. I learned that the Company did not expect the contracts to be dispatched all of the time and that they were also purchased to capture value in the event that market prices exceeded the very high call option strike prices. In 2007 rebuttal testimony,[1] Mr. Duvall stated:

> ….option contracts are purchased to provide reliability and capture value when market prices increase. When the Company buys an option contract, the Company looks for out-of-the-money contracts that have a lower premium as a means providing reliability while keeping costs low, **because the contracts are not expected to be dispatched all of the time.**

It should be noted that since the breakeven prices were approximately 148% of the 2011 expected market price, the likelihood that these contracts would be dispatched during normal operations was very slim at best. From this it is clear that the Company did not need the capacity or energy for normal expected conditions. Rather, these contracts were essentially bets on abnormal conditions where market prices would spike significantly higher.

[1] Greg Duvall Rebuttal Testimony Utah Docket No. 07-035-93

Therefore, it is unlikely these contracts provided any plant deferral value to rate payers. In the end, the only part of the story that holds together is that the Company purchased the contracts to capture value if market prices did increase considerably above that which it had forecast. This is most likely because the Company did not have an Energy Balancing Account (EBA) at the time. Thus, the captured value would have helped to offset the costs the Company might incur in the event of very high market prices, that it may not have been able to pass on to retail customers. For this reason alone the contract should not be considered to be prudent.

Q. BEYOND ENTERING THE MORGAN STANLEY CALL OPTION CONTRACTS, HAS THE COMPANY BOUGHT ANY STF SUPER-PEAK ENERGY FOR THE TEST YEAR TO SERVE UTAH LOAD?

A. No. The Company did not purchase any STF super-peak energy for the Morgan Stanley call option contracts' effective months. Given the fact that the Company did not expect the Morgan Stanley contracts to dispatch under normal conditions, it does not appear that there was an issue of serving Utah Area load requirements, for the period in question, at the time of contract execution. Once again, this points to the contracts being executed to provide a shareholder benefit.

Q. MR. DUVALL CLAIMED IN REBUTTAL TESTIMONY THAT THE MORGAN STANLEY CALL OPTION CONTRACTS WERE PART OF A GROUP OF FRONT OFFICE TRANSACTIONS THAT A 2004 IRP STUDY SHOWED PROVIDED A PRESENT VALUE REVENUE REQUIREMENT BENEFIT OF $639 MILLION AS A RESULT OF DISPLACING NEW GENERATING RESOURCES. DO YOU HAVE ANY COMMENTS?

A. Yes. Super peak call options with a Mona market POD such as the Morgan Stanley call options were not included in the referenced IRP study. The study included 200 MW of HLH Front Office transactions, which were apparently displaced in actual operations with the Morgan Stanley super-peak call options that were not expected to be dispatched during normal operations. The fact that they were not expected to dispatch does not support plant deferral. For these reasons, the referenced study should be ignored.

Q. ON PAGE 63 OF MR. DUVALL'S TESTIMONY HE DISCUSSES VARIOUS ALTERNATIVES TO THE CALL OPTION CONTRACTS AND STATES THAT IF THE CALL OPTION CONTRACTS ARE REMOVED FROM NPC THEY WOULD NEED TO BE REPLACED BY FIXED PRICE PURCHASE POWER CONTRACTS BASED ON THE NOVEMBER 2005 MARKET PRICES FOR 2001. DO YOU AGREE?

A. No. The Company's actions do not suggest they would have done that. Despite the Company's rebuttal NPC showing that they need to purchase approximately 50,000

MWh during super peak hours for July and August of the test year, the Company has not bought any STF energy since the Morgan Stanley contracts were executed. This demonstrates there was not an urgency to purchase energy to meet Utah area load requirements and that there was no inability on PacifiCorp's part to serve Utah area load requirements without the Morgan Stanley contracts. This also points to the Company entering the hedges to protect shareholders.

Q. HAS THE COMPANY PREVIOUSLY TESTIFIED THAT THE CALL OPTION PREMIUMS SHOULD BE REMOVED FROM NPC IF THE CONTRACTS ARE NOT DISPATCHED?

A. Yes. In Oregon Docket UE 191, while I was working at PacifiCorp, I testified that call option premiums should be removed from NPC if the contracts are not dispatched.

Q. WHAT IS YOUR RECOMMENDATION HERE?

A. For the reasons explained above and in my direct testimony, the Commission should disallow recovery of the Morgan Stanley call option contract costs.

Adjustment 5. <u>SHORT TERM TRANSMISSION</u>

Q. MR. DUVALL CLAIMS THAT YOU ARE REJECTING YOUR OWN PROPOSAL. IS THAT AN ACCURATE STATEMENT?

A. No. My adjustment simply improves the short-term transmission normalization method so that it includes the benefit of transmission capacity that was excluded from the Company's filing, to be consistent with actual operations. Failure to include this transmission capacity would pass the associated transmission capacity benefits to shareholders at the expense of customers.

Q. IS YOUR ADJUSTMENT CONSISTENT WITH HOW THE COMPANY NORMALIZES THE PORTION OF SHORT TERM TRANSMISSION CAPACITY THAT IS INCLUDED IN THE COMPANY'S FILING?

A. Yes. The incremental short-term transmission capacity that I included in NPC is calculated in the same manner, using the same 48 month period data, that the short-term transmission capacity already included in the Company's filing was calculated. Consequently and contrary to Mr. Duvall's assertion, the workpapers I prepared, which support my testimony and proposed adjustment, did demonstrate that the Company's normalization methodology should be revised so that customers receive the associated benefits of this transmission capacity.

Q. DID THE COMPANY PROVIDE ANY JUSTIFICATION OF WHY THE BENEFITS OF THE SHORT TERM TRANSMISSION IN QUESTION SHOULD CONTINUE TO BE PASSED THROUGH TO SHAREHOLDERS?

A. No. Mr. Duvall has not made any such argument and therefore, has not met the Company's burden of proof. For this reason, the reasons discussed above and in my direct testimony, the Commission should adopt my proposed adjustment.

Adjustment 6. <u>BLACK HILLS SHAPING</u>

Q. MR. DUVALL RECOMMENDS THAT THE LOGICAL COURSE OF ACTION IS TO USE GRID TO OPTIMIZE WHOLESALE SALES CONTRACTS IN THE SAME MANNER THAT IT IS USED TO OPTIMIZE PURCHASE CONTRACTS. DO YOU AGREE WITH HIS RECOMMENDATION?

A. No. It is obvious that Black Hills, who owns the right to dispatch the contract, knows more about its system and dispatches the contract in the manner that is most beneficial to Black Hills. Since Black Hills' dispatch of the contract is so different than the GRID dispatch, it is clear that the contract should be dispatched based on historical experience not how GRID thinks the contract should be dispatched.

Q. COULD BLACK HILLS DISPATCH OF THE CONTRACT BE A ONE-TIME ANOMALY?

A. No. Black Hills has consistently dispatched the contract in a manner much different than GRID. If it were an anomaly, some of the recent years dispatch would be consistent with GRID. But that is not the case. As shown on Surrebuttal Exhibit UIEC __(MTW-SR1)

Confidential, the historical dispatch of the Black Hills contract is much different than the GRID dispatch in each year.

Q. DO YOU AGREE THAT IT IS NOT FAIR OR CONSISTENT TO NORMALIZE DIFFERENT CONTRACTS USING DIFFERENT RULES?

A. Not in the case of the Black Hills contract. It would be unfair to dispatch the contract with GRID because it would allow the recovery of more costs than the Company incurs serving the contract during actual operations. Further, as I explained above, Black Hills owns the dispatch rights to the contract and it should be dispatched in the manner that they historically dispatch the contract. In the same light, PacifiCorp owns the dispatch rights to various purchase power contracts and they should be dispatched in the manner that PacifiCorp would dispatch the contracts, which is how they are dispatched in GRID. So, my recommendation to dispatch the Black Hills contract based on actual information does not suffer from fairness or consistency issues as Mr. Duvall has asserted. Further, Mr. Duvall's recommendation on this adjustment is inconsistent with his own reference to the Commission's Test Period Order. In his rebuttal testimony he quoted the following comment from the Commission: "the Commission placed all Parties on notice that as it considered 'evidence supporting forecasts in this proceeding, especially deviations from historical trends, [the Commission] will give substantial weight to data reflecting actual verifiable experience.'" Clearly, UIEC's recommendation is consistent with the Commission's statement and Mr. Duvall's proposed Black Hills modeling is not.

Adjustment 8. **DC INTERTIE ADJUSTMENT**

Q. DO YOU AGREE THAT THE PRUDENCE OF THE DC INTERTIE AGREEMENT SHOULD BE BASED ON INFORMATION THAT WAS AVAILABLE AT THE TIME OF CONTRACT EXECUTION?

A. Yes.

Q. WHY IS PRUDENCE OF THE DC INTERTIE AGREEMENT AN ISSUE?

A. The lack of used and usefulness for the test year is directly related to the contract term difference between the Southern California Edison (SCE) Winter Power Sale Agreement (WPSA) and the DC Intertie agreement, which was executed to facilitate the WPSA agreement. The WPSA had a fixed term at the time of contract execution and was terminated pursuant to contract terms on January 1, 2002, while the DC intertie agreement basically extends into perpetuity because it is tied to the life of the AC Intertie. Because of this term difference it is imperative that it be determined whether the Company was prudent in executing an expensive transmission agreement into perpetuity, when the intended purpose of the agreement was merely to facilitate the WPSA, which had a finite term.

Q. HOW DO UTILITIES TYPICALLY SUPPORT DECISIONS TO ENTER CONTRACTS?

A. Typically utilities prepare studies including economic analyses of various alternatives to determine which transaction is the best alternative.

Q. HAS PACIFICORP PROVIDED ANY STUDIES OR ECONOMIC ANALYSES TO JUSTIFY THE EXECUTION OF THE DC INTERTIE CONTRACT?

A. No. The Company has not provided any information to demonstrate the prudence of the contract. Therefore, the Company has not met its burden of proof.

Q. DO YOU AGREE WITH MR. DUVALL'S QUANTIFICATION OF BENEFITS OF THE REAL TIME TRANSACTIONS WITH THE COST OF THE CONTRACT?

A. No. The DC intertie contract is not comparable to the BPA peaking contract. The peaking contract allows the Company to take energy from the BPA system during on-peak hours and return the energy during off-peak hours. In other words it allows the Company to convert off-peak energy into on-peak energy. The DC Intertie contract has no such provision so the comparison is invalid. Further, the BPA contract does not extend into perpetuity like the DC Intertie contract.

Q. DO YOU HAVE ANY COMMENTS ABOUT MR. DUVALL'S CLAIM THAT IF THE DC INTERTIE CONTRACT WERE NOT AVAILABLE TO THE

COMPANY THAT IT WOULD HAVE TO BE REPLACED WITH A NEW 200 MW RESOURCE?

A. Yes. This assumption is really just part of the prudence issue of the DC Intertie contract. We don't know if the contract as it exists today was more prudent than other alternatives. For that matter we don't even know if the Company compared alternatives to the DC Intertie contracts. All we know is that the Company's acquisition of the limited term WPSA was facilitated with a transmission contract that extends into perpetuity, which is not used for customers during the test year. For these reasons the Commission should disallow recovery of the contract cost.

Q. WHAT IS YOUR RECOMMENDATION?

A. The Commission should deny recovery of the contract costs in this case because the contract does not provide any benefits to customers during the test year and the Company has failed its burden of proof to provide any studies or other reasonable information which demonstrates the prudence of their decision to enter the contract. Further, it is also worth noting again that my recommendation is consistent with the Washington Commission's disallowance of the DC Intertie contract costs because the contract is not being used during the test year as was the case in the Washington docket.

Adjustment 9. **<u>CENTRALIA PTP WHEELING</u>**

Q. DID THE COMPANY PREPARE AN ECONOMIC ANALYSIS TO SUPPORT THEIR ACQUISITION OF THE CENTRALIA PTP TRANSMISSION CONTRACT?

A. Yes. However, as discussed in my following testimony the Company failed to adequately review and/or test the risk of competing bids for the transmission, which ultimately led the Company to base its request for a five year contract term on insufficient information.

Q. ON PAGE 56 OF MR. DUVALL'S REBUTTAL TESTIMONY HE STATES: BECAUSE THE CONTRACT WAS UNAVAILABLE ON A YEAR-BY-YEAR BASIS, IT SHOULD NOT BE EVALUATED IN THAT MANNER FOR RATEMAKING PURPOSES. DO YOU AGREE THAT THE CONTRACT WAS NOT AVAILABLE ON A YEAR-BY-YEAR BASIS?

A. No. The contract was in fact available on a year-by-year basis. Page 4 of Confidential Attachment UIEC 14.1, states: [redacted] So, the year-by-year term option should be considered in any regulatory review of the contract.

Q. WHAT WAS PACIFICORP'S MAJOR CONSIDERATION WHEN DECIDING WHAT CONTRACT TERM IT WOULD REQUEST?

A. According to Mr. Duvall's rebuttal testimony, the Company was concerned that it had firm transmission rights to serve load during a period of potential change to resource and transmission portfolio mix and about the number of parties competing for the same transmission capacity. Based on this reasoning, the Company bid for a five year contract term, because they thought it was industry standard for rolling-over contracts for successive terms and would discourage other bidders.

Q. WAS THE COMPANY EVER AT RISK OF LOSING THE CENTRALIA PTP TRANSMISSION RIGHTS?

A. No. The Company had the right of first refusal, whether they bid one year, five years or more. So, they were never at risk of not having these firm transmission rights. The only perceived risk they had was that someone might have bid for a longer term or a higher price. However, the transmission capacity did not have an unlimited value, so there may not have been much exposure to higher prices and a longer term.

Q. DID THE COMPANY PREPARE AN EVALUATION OF POTENTIAL COMPETING BIDDERS?

A. No. According to the Company they did not prepare an evaluation.

Q. DO YOU FIND FAULT WITH THE COMPANY'S EXECUTION OF THE FIVE YEAR CONTRACT TERM WITHOUT AN EVALUATION OF THE RISK OF COMPETING BIDS?

A. Yes. Given the [redacted] million annual cost of this five year contract, the Company should have undertaken a study to determine whether it was likely that there would have been competing bidders to be better informed of the proper bid term. The shorter the contract term, the higher the likelihood that the Company could minimize contract costs.

Q. WHAT IF THE STUDY ON COMPETING BIDS HAD BEEN INCONCLUSIVE?

A. If the study was undertaken and proved to be inclusive or information was not available so that such an evaluation could have been made, the next logical step that should have been taken was to request an annual term contract to determine if there were any competing bidders. Whether there were or there weren't competing bids, this process would have provided the Company with the information necessary to bid for the optimal contract term so it could minimize costs and provide greater assurance that the contract would be fully utilized. Since the Company failed to undertake these actions to prudently evaluate the contract term and because the contract, for almost all practical purposes is not used and useful during the test year, I continue to recommend that the Commission adopt my recommendation to disallow all but the very limited portion of the capacity that is being used by the Company.

Adjustment 13. **<u>NAUGHTON 3 OUTAGE</u>**

Q. MR. DUVALL CLAIMS THAT BECAUSE THE COMPANY ACTED PRUDENTLY BY NEGOTIATING A LIQUIDATED DAMAGE CLAUSE WITH THE CONTRACTOR AND EXERCISING THAT CLAUSE WHEN POOR CONTRACTOR PERFORMANCE NEGATIVELY IMPACTED THE OUTAGE, THAT IT SHOULD BE ALLOWED TO RECOVER OUTAGE COSTS AGAIN BY INCLUDING THE OUTAGE IN NPC. DO YOU AGREE?

A. No. Mr. Duvall appears to miss the thrust of my recommendation. My proposed adjustment is not based on the Company prudently dealing with the liquidated damage issue, it is based on imprudence on the Company's part for hiring an under qualified contractor. It also included the fact that the Company had already collected $500,000 in liquidated damage fees for replacement power costs, which was not passed through to customers. I do not believe customers should be asked to pay for imprudent Company actions or pay the Company for replacement power costs that they were already paid for.

Q. DID MR. DUVALL ADDRESS YOUR ISSUES OF COLLECTING REPLACEMENT POWER COSTS TWICE AND THE IMPRUDENT HIRING OF AN UNDERQUALIFIED CONTRACTOR?

A. No. For these reasons, I continue to recommend that the Commission disallow the inclusion of the imprudent outage in NPC.

Adjustment 17. **<u>MARKET CAPS</u>**

Q. WHAT BENCHMARK HAS PACIFICORP USED AS A STANDARD TO DETERMINE WHETHER THE MARKET CAP ADJUSTMENT IS APPROPRIATE?

A. As discussed recently in Mr. Duvall's rebuttal testimony in Wyoming Docket No. 20000-ER-384-10, the Company's standard benchmark has been a comparison of proposed coal generation to the 48-month historical average. Based on my experience, if coal generation has been egregiously higher than the historical average, it has generally been considered that market caps are necessary. It has also been previously recognized that even with market caps coal generation does not have to be equal to or below the historical average. For example, in Wyoming Docket No. 20000-ER-03-198, authorized coal generation exceeded the historical average by approximately 193,000 MWh, even though market caps were utilized.

Q. MR. DUVALL CLAIMS THAT YOU FAILED TO ACCOUNT FOR THE IMPACT OF INTEGRATING WIND GENERATION ON COAL GENERATION. DO YOU AGREE WITH HIS TESTIMONY?

A. No. Mr. Duvall's testimony is either misleading or is a holdover from another docket. I did not specifically address the impact of wind integration on coal generation because it was not necessary. My proposed NPC, which included wind integration, with the exception of making Gadsby units 4, 5, and 6 must run units, which I discussed earlier in this testimony, required no further analysis, because as shown on Table 2 of my direct testimony, my proposed coal generation was lower than PacifiCorp's proposed coal generation. Since PacifiCorp believed their higher level of coal generation was reasonable, there was no reason to do further analysis.

Q. HAVE YOU PREPARED AN UPDATE TO TABLE 2 IN YOUR DIRECT TESTIMONY?

A. Yes. I updated the Company's rebuttal NPC to include my adjustments which are still being contested, that impact coal generation. As shown in the following Table 1, the answer is still the same. The UIEC NPC study which does not include market caps, still shows less coal generation than in PacifiCorp's Rebuttal NPC. Therefore, from a coal generation perspective the market caps are no longer necessary.

Table 1
Coal Generation
MWh /1

	HLH	LLH	Total
PacifiCorp Rebuttal	24,994,228	19,088,100	44,082,328
UIEC /2	24,964,500	19,010,233	43,974,733
Difference	29,728	77,868	107,595

/1 June 2012 test year
/2 PacifiCorp Rebuttal Plus UIEC Adj. that affect coal generation

Q. HAVE YOU PREPARED ANOTHER ANALYSIS WHICH SHOWS THAT MARKET CAPS ARE NOT NECESSARY TO PREVENT GRID FROM RUNNING THE COAL GENERATION UNITS TOO MUCH?

A. Yes. I compared the HLH coal generation from two GRID runs. The first run was PacifiCorp's rebuttal NPC and the second run was PacifiCorp's rebuttal NPC adjusted to exclude market caps for all markets except Mona. The runs showed virtually identical coal generation during HLH. Once again, this information does not support the utilization of market caps because coal generation runs too much during HLH.

Q. DO YOU AGREE WITH THE COMPANY THAT MODELING WIND INTEGRATION IN GRID REDUCES COAL GENERATION BELOW THE 48-MONTH HISTORICAL AVERAGE?

A. That is a hard question to answer because there are so many moving parts. If one were to assume that the Company has calculated wind integration reserves correctly, which according to Mr. Falkenberg's testimony is not the case, and one assumes that none of the other adjustments proposed by the parties that impact coal generation are appropriate, then the Company's analysis shows that normalized coal generation is lower than the 48-month historical average. However, that analysis still does not demonstrate that a market cap adjustment is appropriate as discussed in my following testimony.

Q. THE FOOTNOTE ON PAGE 45 OF MR. DUVALL'S TESTIMONY SUGGESTS THAT WITHOUT MODELING WIND INTEGRATION GRID PRODUCES MORE COAL GENERATION THAN DURING THE 48-MONTH HISTORICAL PERIOD. IS THAT A MEANINGFUL COMPARISON?

A. No. Mr. Duvall's analysis is an apples-to-oranges comparison. During the normalized period, the system is different than the historical period in a number of ways. These differences cause GRID to produce more coal generation during the normalized period than occurred during the historical period. Those differences include, higher retail loads, more coal generation capacity and the addition of the Energy Gateway transmission system. Then there are also various normalizing adjustments proposed by the Parties, which if adopted would further increase coal generation. For example, if the Commission adopts my proposed Naughton 3 outage adjustment, the result would be more low cost coal generation. It should also be noted that increases in wind integration reserve requirements and load following reduce normalized coal generation. The whole point to this is that in order for the Company's analysis to be valid, which it is not, test year differences would have to be normalized. Therefore, the Commission should ignore the Company's testimony on its analysis because the analysis is invalid.

Q. DID YOU ATTEMPT TO PREPARE SUCH AN ANALYSIS?

A. Yes. However, the Company was not able to provide the actual amount of wind integration reserves and load following reserves carried on coal generation for all years of the 48-month historical period. So, it was not possible to complete such an analysis.

Q. DOES PACIFCORP ACTUALLY CURTAIL ECONOMIC COAL GENERATION?

A. They don't know. In response to WIEC data request 24.6,[2] the Company was asked to provide the amount of economic generation that was curtailed during on and off-peak hours for the 48-month period ended June 2010 due to a lack of market. In response they stated, "The Company does not have the requested information." This is not supportive of the necessity of market caps.

Q. DOES PACIFICORP USE MARKET CAPS IN OTHER PROCESSES OR ANALYSES SUCH AS BUDGETING, 10 YEAR PLANNING, RESOURCE ACQUISITION ANALYSIS OR INTEGRATED RESOURCE PLANNING?

A. No. According to the Company, market caps are not modeled in any of their internal processes. In response to UIEC Data Request 9.5 PacifiCorp stated:

> …the Company states that the market cap methodology used in this case is designed to model normalized net power costs for regulatory purposes. Because no business group other than the Net Power Costs group conducts such modeling, no other group in the Company has reason to utilize this methodology.

[2] Wyoming Docket No. 20000-ER-384-10

Q. CAN YOU PROVIDE SOME SPECIFIC EXAMPLES OF BUDGETS OR ANALYSES THAT DID NOT USE MARKET CAPS?

A. Yes. Market Caps were not used in the 10 Year Plan NPC, which is a forecast of actual NPC according to PacifiCorp's response to UIEC 6.46. In that response PacifiCorp stated:

> … the NPC studies used in the budget context are designed to forecast actual NPC as accurately as possible in the face of changing variables…

If market caps are not used in a forecast that is designed to be as accurate as possible because the Company is forecasting expected earnings and making plans regarding the future operation of the system, market caps should not be used for normalized NPC. Other examples of analyses where the Company did not use market caps are the $6.0 billion Energy Gateway transmission project, the Lakeside 2 analysis and the APEX analysis. It is well known that the economics of large resource acquisitions depend a great deal on how much energy can be sold in the wholesale market, because large resources are never a perfect fit for the Company's load profile. Yet, the Company does not model market caps which would have a direct bearing on the economics of various resource alternatives.

Q. IS THERE AN APPARENT PATTERN IN THE COMPANY'S USE OF MARKET CAPS?

A. Yes. When the Company is spending its money to acquire resources and wants to recover the cost from customers or receive approval to acquire a resource, markets caps are not used, which coincidently makes the resources look more economic. On the other hand, when the Company is requesting rate increases from the Commission, market caps are employed in NPC, which coincidently increases NPC. This situation itself provides the Commission enough evidence to reject the use of market caps. The following testimony provides further evidence supporting the rejection of market caps.

Q. MR. DUVALL CLAIMS THAT SETTING WHOLESALE MARKET CAPS BASED ON THE 48-MONTH AVERAGE OF HISTORICAL WHOLESALE SALES PROPERLY CAPTURES THE LIQUIDITY OF THE WHOLESALE MARKET. DO YOU AGREE?

A. No. Mr. Duvall's statement would only be accurate if market conditions during the 48-month historical period were identical to the normalized period and that is simply not the case. For example, the Company's system is different, loads are different, market prices for natural gas and electricity are different, hydro conditions are different, the WECC system and other electrical provider systems are different. These differences invalidate a strict adherence to the historical volume of wholesale sales as proposed by the Company because system differences produce different results which are not comparable.

Q. HAVE YOU REVIEWED THE RESULTS OF GRID RUNS WITH MARKET CAPS AND WITHOUT MARKET CAPS?

A. Yes. The run differences are in stark contrast to what we have heard from PacifiCorp over the years and are in contrast to how GRID was designed to operate. For many years we have heard that PacifiCorp is able to use its large transmission system to monetize market price differences between various market hubs by buying energy at lower market priced hubs and reselling that energy at higher priced market hubs. That is just the opposite of what happens when the Company uses market caps. As shown on the Table 2 below, the market caps force GRID to reduce the amount of cost effective system balancing purchases it makes at lower priced markets and resells at higher priced markets. This is contrary to what PacifiCorp has told us over the years and especially troubling given the high hydro runoff in the Northwest and price differentials between market hubs.

Table 2			
GRID Balancing Sales and Purchases			
MWH			
		Adjusted	
	PacifiCorp	PacifiCorp	
	<u>Rebuttal /1</u>	<u>Rebuttal /2</u>	<u>Difference</u>
System Balancing Sales	8,507,558	9,562,514	1,054,957
System Balancing Purchases	6,337,008	7,290,823	953,815
/1 Rebuttal filing			
/2 Rebuttal NPC adjusted to exclude market caps			

Q. ARE THE RESULTS SHOWN IN TABLE 2 CONSISTENT WITH MR. DUVALL'S OWN TESTIMONY?

A. No. On page 47 of his rebuttal testimony regarding an arbitrage adjustment proposed by OCS witness Mr. Falkenberg, Mr. Duvall states:

> GRID fully utilizes the transmission included in the model to make arbitrage transactions through system balancing sales and purchases. There are many hours when GRID is simultaneously purchasing power from one market and selling to a different market at a higher price. By definition, this is arbitrage. As a result, NPC are lower than they otherwise would be without these arbitrage transactions. In GRID, system balancing sales and purchases act as a proxy for future short-term firm sales and purchases, including arbitrage transactions, and are eventually replaced with real transactions.

As shown on Table 2, the market cap adjustment is preventing the GRID model from doing what Mr. Duvall says GRID is supposed to do.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. For all of the forgoing reasons I discussed above, the Commission should reject the Company's proposed use of market caps, with the exception of the market caps for the illiquid Mona market.

Adjustment 21. <u>NATURAL GAS SWAPS</u>

Q. MR. BIRD TESTIFIED THAT YOU PREVIOUSLY TESTIFIED IN A WYOMING DOCKET[3] THAT THE COMPANY SHOULD DIVERSIFY ITS MARKET PRICE RISK BY HEDGING ON A NEAR TERM, INTERMEDIATE TERM AND A LONG TERM BASIS AS OPPOSED TO HEDGING EVERYTHING ON A NEAR TERM BASIS. DO YOU BELIEVE THAT TESTIMONY IS INCONSISTENT WITH THE TESTIMONY DR. MALKO FILED IN THIS DOCKET?

A. No. First and foremost, in the Wyoming docket [redacted] Second, I advocated more diversification in the form of near term, intermediate term and long–term contracts as opposed to doing everything on a near term basis. Neither of these points is inconsistent

[3] Wyoming Docket No. 20000-315-EP-08

with Dr. Malko's proposed adjustment in this docket, which is predicated on the need for more diversification for natural gas swaps. Further, while the Company has attempted to say UIEC is critical of all of the Company's natural gas hedging, that is not the case. Dr. Malko's proposed adjustment specifically relates to natural gas swap transactions.

Q. FROM MR. BIRD'S TESTIMONY IT APPEARS THAT YOU WERE ADVOCATING INTERMEDIATE AND LONGER TERM HEDGING DESPITE THE FACT THAT MARKET PRICES WERE VERY HIGH AT THE TIME OF YOUR WYOMING TESTIMONY. IS THAT THE CASE?

A. Of course not. My testimony regarding the Company having had great experience in terms of controlling costs with longer term hedging was in reference to the long-term Hermiston natural gas contract, which I view as an opportunistic hedge that has significantly reduced NPC over the term of the contract. This is also consistent with Dr. Malko's testimony.

Q. DO YOU AGREE WITH MR. APPERSON'S SUGGESTION THAT THE ANALYSIS PREPARED FOR DR. MALKO'S PROPOSED ADJUSTMENT IS INCOMPLETE?

A. No. If the intent of the adjustment were to propose an adjustment relative to the Company's entire hedging program he would be correct, but that is not the intent of Dr. Malko's adjustment, which focuses only on the natural gas swaps. One could draw an analogy to an investment portfolio, where an investment manager used various strategies for a client. If a component of that strategy continually lost money, while the other components made money, it would not be prudent for the investment manager to revise his entire investment strategy. Rather, the prudent thing to do would be to revise the strategy component that was not performing as Dr. Malko is recommending in this case.

Q. DO THE INCORRECT SIGNS ON THE ELECTRICITY SWAPS IDENTIFIED BY MR. APPERSON ON EXHIBIT___(MTW-5) IMPACT DR. MALKO'S PROPOSED ADJUSTMENT?

A. No. However, they have been corrected through an errata filing.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

CERTIFICATE OF SERVICE
(Docket No. 10-035-124)

I hereby certify that on this 19th day of July 2011, I caused to be emailed, a true and correct copy of the foregoing **SURREBUTTAL TESTIMONY AND EXHIBITS OF MARK T. WIDMER ON REVENUE REQUIREMENT ON BEHALF OF UIEC** to:

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