In the Matter of the Application of
PacifiCorp for Approval of its Proposed
Electric Service Schedules and Electric Service Regulations

Docket 04-035-42

DPU Exhibit 7

Direct Testimony of Andrea Coon
Division of Public Utilities

December 3, 2004

Q. Please state your name and employer.

A. My name is Andrea Coon; I work for the Division of Public Utilities.

Q. What is your position with the Division?

A. I am a Technical Consultant for the Energy Group.

Q. What is your educational background and experience?

A. I have a B.S. in Economics and a Masters degree in Communications. I have also completed all the coursework towards a PhD. in Economics from the University of Utah. I have been working in electricity regulation for just over 3 years, first at the Committee of Consumer Services, and now at the Division. Over this time I have worked on a variety of energy issues with my focus on electrical issues. I have recently filed testimony before the Commission regarding special contract rates and plant certification proceedings.

Q. What is the purpose of this direct testimony?

A. The purpose of this testimony is to identify and quantify changes that should be made to PacifiCorp's Net Power Costs for the inclusion of those costs in the current Utah rate case.

Q. What is the value that PacifiCorp has filed as a Total Company Net Power Cost for its April 1, 2005 – March 31, 2006 test year?

A. As identified in the direct testimony of company witness Mark T. Widmer (page 2, line 7), PacifiCorp's Total Company Net Power Cost (NPC) for the filed test year is approximately $745 million.

Q. What do you believe the value should be?

A. Based on the adjustments described below, my analysis indicates that the appropriate Total Company NPC that should form the basis for ratemaking in Utah is $672 million, a reduction of approximately $73 million.

Q. What are the adjustments that account for this $ 73 million reduction?

A. There are 10 issues listed below that account for this reduction. Each is listed with the corresponding reduction according to issue-by-issue runs. In addition there is an adjustment at the bottom to account for the changes that come from running issues 1, 2, 3, 4, 8 and 9 simultaneously, which gives the total of $73 million.

	Issue	Reduction
1.	Revision to Utah Load Forecast	$28.5 million
2.	CT Commitment and Quick Start Reserve	$13.6 million
3.	Revision to Forecast of System Losses	$12.6 million
4.	More Appropriate Regulation Amounts	$8.5 million
5.	Gadsby Steam Generation Too High	$5.0 million
6.	BPA Peaking Contract	$3.3 million

7.	Hydro Load Following	$3.0 million
8.	Weighting of Vista Hydro Scenarios	$1.5 million
9.	Revision of CT Forced Outage Rate	$0.2 million
10.	Inclusion of New Wind Resources	$1.2 million
	Effect of Overlapping	($4.43 million)
	TOTAL:	**$72.97million**

It is important to note that four of these adjustments are still estimates and will be firmed up later in the proceeding. Also, it is important to note that there are several issues that I will not address at this time because PacifiCorp has indicated these will be included in its rebuttal testimony. These issues include revised generation and reserves from curtailable contracts and DSM programs, the Swift Hydro facility, and updated market prices. I reserve the right to review, adopt, or reject these changes later in this proceeding.

Q. Please describe the issue labeled as "Revision to Utah Load Forecast" that accounts for approximately $28.5 million of your proposed NPC reduction.

A. In his testimony on sales, Company witness Reed Davis showed a 5.9% growth in Utah sales from the last year of actual data to the test year. PacifiCorp corrected this growth rate in DPU 6.7 and DPU 9.47, however so that in the test year as filed, Utah sales are projected to increase 9.6% over the last year of actual, or almost twice as much as what was shown in Mr. Davis' testimony. This is an increase of approximately 4.7% per year. The Division believes that some change is necessary in this area. Specifically, the Division does not agree with the abnormally high projections as compared to average growth rates.

The historical Utah sales value shown in Exhibit DPU 7-1 is taken from Data Request DPU 9.45. These data did not include sales for the period ending March 2004, so those data were taken from Data Request DPU 9.47. The data show that the five-year average annual growth rate for Utah sales is 3.0% and the most recent four years have an average annual growth rate of 1.7%. The growth rate used by PacifiCorp of 4.7% per year is considerably higher than these figures. In order to develop a more historically consistent estimate, the 5-year average growth rate of 3.0% was used. This reduced Utah sales by 686,935 MWH. This becomes approximately 749,894 MWH when losses are included using the same rate of losses as PacifiCorp used in its base runs.

This adjustment reduces NPC by $28,548,126 when run through GRID, but may or may not decrease final rates due to fewer projected MWH over which to allocate fixed costs. The Division realizes that the growth rate will impact numerous other areas of the case including allocation and revenues; preliminary examination indicates that revenues may decline by more than $35 million. A data request for the calculations necessary to complete the overall adjustment has been issued to PacifiCorp and is outstanding. The Division will complete this adjustment and file amended testimony upon receipt of the necessary information from PacifiCorp.

Q. Please describe the issue labeled as "CT Commitment and Quick Start Reserve" that accounts for approximately $13.6 million of your proposed NPC reduction.

A. The dispatch of the Gadsby and West Valley combustion turbines (CT) in GRID is incorrect. These CTs are not being dispatched in GRID in a manner consistent with either actual dispatch or normal utility practice. The heat rates for these units from the model are also inconsistent compared to historical values. In actuality, the Gadsby and West Valley CTs generally are dispatched near their maximum capacity. Because these CTs have steep heat rate curves, there are large penalties in both heat rate and cost for dispatching them at low capacities.

In PacifiCorp's GRID run, the three Gadsby CTs never operate above half capacity. This is also true for one of the West Valley CTs. Overall, the West Valley CTs operate at much lower capacities in GRID than they do in actuality.

It appears that the CT commitment logic in GRID is not correctly handling PacifiCorp's CTs. The model should be programmed to allow the CTs to provide reserves even when the CTs are off-line. Instead, the model appears to be committing CTs and then running at half capacity in order to provide reserves. A revised GRID analysis was performed whereby each of the CTs was committed at an artificial minimum capacity of 0.001 MW to "trick" GRID into appropriately simulating the commitment of the CTs. This yields an adjustment of $13,585,047 as a reduction to PacifiCorp's NPC.

Q. Please describe the issue labeled as "Revision to Forecast of System Losses" that accounts for approximately $12.6 million of your proposed NPC reduction.

A. PacifiCorp claimed in DR DPU 11.7 to have used the value of 9.9329% for total system losses, which includes line losses and transformer losses, as a percent of total sales in its test year cost calculation. This rate is higher than actual losses in recent years and the Division has not seen justification for raising the rate above that experienced in the recent past. Losses over the last five years, shown in Exhibit DPU 7-2, have fluctuated between approximately 8.7% and 9.9%, with a five-year average of 9.269%. This seems to be a small difference, but when it is applied to over 50 million MWH in sales, using this five-year average value reduces the GRID test-year energy requirements by approximately 336,786 MWh and results in a reduction in NPC of $12,602,986.

Comparing forecasted sales with load in GRID shows that losses in GRID are not what PacifiCorp claimed in its data response. Losses in GRID are 9.9999%. Adjusting this level of losses to the 5-year average would reduce energy requirements by a further 33,299 MWH. This larger adjustment is included in the calculation of the effect of overlapping issues.

Q. Please describe the issue labeled as "More Appropriate Regulation Amounts" that accounts for approximately $8.5 million of your proposed NPC reduction.

A. PacifiCorp's GRID modeling appears to require too many reserves; this is reflected by the CTs holding excessive amounts of spinning capacity as previously discussed. Total reserves consist of spinning, non-spinning and regulating reserves. The North American Electric Reliability Council (NERC) fixes the formulas for spinning and non-spinning reserves. The NERC requirement for regulating reserves necessitates that PacifiCorp carry sufficient additional spinning reserves needed to put the system back into balance within 10 minutes of a disturbance. In GRID, PacifiCorp calculates regulating reserves based on the change in load from one hour to the next. PacifiCorp also sets a minimum and maximum amount of regulating reserves of 50 MW and 125 MW, respectively, on each side of the system (i.e., both east and west). However, a review of actual operations and a comparison of GRID results with actual unit operation suggest that such modeling parameters in GRID are too high and inappropriately elevate the test year NPC results. Specifically, the modeled dispatch and heat rates of the CTs in GRID indicate that the level of regulating reserves in GRID is not consistent with actual dispatch and, therefore, actual reserves.

Revised GRID runs were performed to attempt to correct this. The first adjustment was to reduce the level of regulating reserves on the west side. The west side is hydro heavy and therefore does not require many regulating reserves beyond the level of spinning and non-spinning reserves already required. Therefore, the DPU GRID modeling set a minimum and maximum amount of regulation in the west at 0 MW and 50 MW, respectively. The limits on regulation in the east were set to 0 MW and 125 MW (minimum and maximum, respectively) and the transfer of reserves from west to east was increased from 100 MW to 200MW. Theses changes were made in an attempt to force GRID to more closely simulate actual CT generation and not because these are the perfect way to model regulation.

These modeling changes, however, did not fully resolve this complex issue. The CT dispatch and heat rates were improved over the filed PacifiCorp test year GRID results but still did not perfectly match historical dispatch and heat rates. Thus, the NPC reduction of $8,456,803 is conservative.

Q. Please describe the issue labeled as "Gadsby Steam Generation Too High" that accounts for approximately $5.0 million of your proposed NPC reduction.

A. The level of generation and costs for the Gadsby Steam units in GRID is much higher than recent actual. GRID's test year generation at the Gadsby steam plant is approximately 70% or 111,200 MWH higher than generation for calendar 2003. GRID's generation for January through September is 228% or 154,377 MWH higher than actual generation for the January through September period in 2004. Actual generation in these comparisons is calculated from the hourly data in DR DPU 11.3b.

Q. Are there other reason's that generation from the Gadsby steam units should be less than it is in GRID?

A. Yes. The addition of the Currant Creek combustion turbines means that the Gadsby steam units would probably be needed even less than they were in 2003 and 2004. This further emphasizes that GRID's generation and cost for the Gadsby steam plant are too high.

Q. What are the reasons for the Gadsby steam plant's generation and cost in GRID being too high?

A. There appear to be two key reasons, though it could be a combination of several factors. First, as discussed in several places in this testimony, GRID seems to be carrying significantly more operating and regulation reserves on its generation units than in actuality. In trying to reach this reserve level, GRID is dispatching the Gadsby steam units. Unlike the new combustion turbines, the Gadsby steam units are capable of carrying reserves only when they are dispatched. The higher than actual level of operation of the Gadsby steam units is just another indicator that reserves are too high in GRID.

The second reason that GRID dispatches the Gadsby steam units at too high a level is that GRID appears to ignore operations and maintenance costs when making its commitment and dispatch decisions. The Gadsby steam units have high O&M costs – total costs of the units were $91/MWH according to PacifiCorp's FERC Form 1. For most of PacifiCorp's units, variable O&M costs are relatively small. Variable O&M appears to be an important consideration for the Gadsby steam units, however. Therefore, since GRID is dispatching the steam units more than in practice, GRID may not be adequately accounting for variable O&M in making its dispatch decisions.

Q. What is the size of the adjustment for the Gadsby steam plant?

A. We are still developing GRID runs that result in the Gadsby steam plant being simulated in a manner that more closely resembles actual operation. Our current estimate is that this could reduce NPC by about $5 million, but it may be higher. We expect to have a final number by December 10, 2004.

Q. Please describe the issue labeled as "BPA Peaking Contract" that accounts for approximately $3.3 million of your proposed NPC reduction.

A. PacifiCorp has a contract with the Bonneville Power Administration (BPA) for BPA to provide capacity to PacifiCorp during the day and for PacifiCorp to return the power at night. The contract is somewhat complex with many specific details to be accounted for, such as the level of capacity, the specific hours of take and return and the weekend operation. In the test year, the BPA Peaking contract has a maximum take of 460 MW, so this is quite a large contract.

Q. How is this contract modeled in GRID?

A. GRID models the BPA "take" with a similar load shape on most weekdays. GRID starts the "take" at 230 MW for a couple of hours, increases it to 345

MW for a three hours, then reaches full capacity of 460 MW for a few hours and then reverses the morning ramp up.   This simple approach does not match actual operation and does not achieve full value for the contract.

Q. How can greater value be achieved for the BPA contract?

A. Greater value can be achieved by making the BPA "take" follow changes in load more closely. This would also make the model results resemble actual practice more closely. The BPA contract cannot follow load exactly, but since load changes in a similar pattern each day in a season, the BPA contract can and has followed load to a certain extent in actual practice.

Q. What is the advantage of following load and how does it lead to cost savings?

A. GRID does not follow load closely with either hydro or the BPA peaking contract. Therefore, GRID is following load with either the CTs or the coal units. Hydro sources, either PacifiCorp's own hydro generation or the BPA peaking contract, are good units to follow load with. One reason that these are good is that the hydro can ramp up and down very quickly. The second is that hydro is typically less expensive to run than are any of the fossil fuel resources.

Q. How does the DPU plan to model the BPA Peaking contract in its alternative run?

A. There is no easy way to fix the BPA peaking contact in GRID. Therefore, the DPU plans to use actual BPA take and return in a GRID run. Running actual BPA Peaking contract take and return should result in lower costs than GRID projected in the base case. We are currently working on completing this run and expect to have a final number no later than December 10, 2004.

Q. Please describe the issue labeled as "Hydro Load Following" that accounts for approximately $3.0 million of your proposed NPC reduction.

A. Like the BPA peaking contract, hydro generation does not follow load as well as it could. Hydro is only modeled in a rough fashion in GRID. Hydro is assigned a priority weight, but does not actually follow the changes in load. Instead, GRID makes the CTs, CCs and the coal units follow load too much. This is not the lowest cost approach and not the way it is done in actual operation. GRID does not appear to have optimized hydro generation.

Q. Did you estimate a cost savings from a more optimal method of hydro generation?

A. Like the BPA Peaking contract, actual hydro generation should be inserted into GRID to see if it results in lower costs than GRID's crude hydro dispatch algorithm. Using actual operation should save about $3 million compared to the base case GRID modeling. This number is based upon estimates of changing power purchase patterns. We are currently working on completing this run and expect to have a final number no later than December 10, 2004.

Q. Are there any adjustments or considerations that will be needed in order to perform this modeling?

A. Yes. Actual generation from 2003 should be scaled up to the average level. Since actual generation was significantly below average in 2003, using the actual would not have been an accurate comparison. Also, when putting in actual generation, the reserves from these hydro units were lost. Thus, reserves should be added back to a comparable level as was used in actual practice during average hydro conditions.

Q. Please describe the issue labeled as "Weighting of Vista Hydro Scenarios" that accounts for approximately $1.5 million of your proposed NPC reduction.

A. PacifiCorp's hydro assumptions in GRID are based on a new hydro model called Vista. Vista develops 19 hydro scenarios, and each of them is weighted with the same probability of occurrence (5.26%, or $1/19^{th}$) in GRID. PacifiCorp's approach, which essentially uses weights based on a uniform distribution, assigns too much weight to extreme weather scenarios such as high rainfall or extreme drought, meaning that it does not assign an appropriate weighting for the mid-range hydro scenarios that are more likely to occur. Further, PacifiCorp's hydro scenarios are skewed, but their weights ignore this skewness.

Using weights developed from a normal distribution more closely matches actual historical weather conditions and places more emphasis on the likely mid-range scenarios and less emphasis on the extremes. Though the weights are from a normal distribution, they are slightly skewed to account for the skewness in PacifiCorp's hydro scenarios. Exhibit DPU 7-3 compares the uniform PacifiCorp distribution to a normal distribution, where the probability weight on the middle scenario is the highest and probabilities decline toward the extremes or tails. Note that the probabilities associated with the two end scenarios increase slightly to reflect the probability of all weather scenarios out to the highest rainfall or most extreme drought.

Applying probabilities from a normal distribution to Vista's 19 hydro scenarios reduced NPC by $1.553,929 million.

Q. Please describe the issue labeled as "Revision of CT Forced Outage Rate" that accounts for approximately $0.2 million of your proposed NPC reduction.

A. As described in PacifiCorp's attachment to its response to DPU DR 9-29, in determining the test year forced outage rates (FOR) for the Gadsby and West Valley CTs, PacifiCorp averaged two years of historical FOR and two years of anticipated FOR represented by the manufacturer. They performed this calculation incorrectly, however. They included only 3 numbers in the calculation, but still divided by four to get an average. Thus, the CT Forced outage rates in GRID are incorrect.

The DPU believes that a mere correction to PacifiCorp's arithmetic is not the appropriate approach, however. The Gadsby and West Valley CTs will be about four years old during the test year, which is roughly the time that units transition to a mature FOR. It is inappropriate to use a FOR that places so much weight on the CTs performance during the early years, when units typically suffer higher FOR. Therefore, a DPU GRID run was performed where the CTs' FOR was lowered to an estimate of a mature FOR of 4.2%. Making this change resulted in a reduction in NPC of $175,745.

Q. Please describe the issue labeled as "Inclusion of New Wind Resources" that accounts for approximately $1.2 million of your proposed NPC reduction.

A. PacifiCorp issued a request for proposals (RFP) for 1,100 MW of renewable resource capacity on February 5, 2004, with the bids due on March 9, 2004. The RFP anticipated that 100 MW of resources would be sought for 2005, with an additional 200 MW annually through 2010. It is my understanding that PacifiCorp selected a short list, but that the negotiation process with the bidders of these projects stalled during much of 2004 because of the uncertainty surrounding the extension of the federal production tax credit (PTC). Hence, specific projects have yet to be contracted. However, Congress extended the PTC on September 23, 2004, with an expiration date of December 31, 2005. Thus, for renewable projects to receive the benefits of the PTC, they must be operating by the end of next year. Given PacifiCorp's advanced stage in its renewable solicitation, it is in an ideal position to capitalize on the PTC extension and secure projects for 2005.

PacifiCorp's current GRID modeling does not include any additional renewable energy projects from the Company's solicitation. This is unlikely to be the case in reality. Arguably, given the current expiration of the PTC at the end of 2005, it may make sense for PacifiCorp to advance its procurement of renewable capacity from what was slated for later years. PacifiCorp stated in DR DPU 16.20 that it intends to have 100 MW on line by the end of 2005, but did not include it in its base GRID run because the contract had not been finalized. They further state that they intend to include 100 MW of wind in their rebuttal testimony. In subsequent discussion on December 1, 2004, PacifiCorp indicated that wind will not be included in the GRID update. Therefore, the DPU evaluated a case that assumes that the originally intended 100 MW of renewable resources would be added by October 1, 2005 and provide 6 months of energy. The analysis included a wind project with a 30% capacity factor added to the system with a price of $35/MWh. The resulting reduction was approximately $1.2 million.

Q. Do you have any other issues to address?

A. Just one. I have been examining the prudence surrounding the West Valley CT lease, but have not as yet been able to complete this analysis. Therefore, I will reserve this issue for discussion at a later time in this proceeding.

Q. Does this conclude your direct testimony?

A. It does.