

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND)	
TRANSPORTATION COMMISSION,)	
)	Docket No. UE-050684
Complainant,)	
)	Docket No. UE-050412
vs.)	
)	<i>(consolidated)</i>
PACIFICORP d/b/a PACIFIC POWER &)	
LIGHT COMPANY)	
)	
Respondent.)	

EXHIBIT NO. ___(RJF-11)

DIRECT TESTIMONY OF ANDREA COON

November 3, 2005

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

1 **Q. Please state your name and employer.**

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

3

4 **Q. What is your position with the Division?**

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

6

7 **Q. What is your educational background and experience?**

8 A. I have a B.S. in Economics and a Masters degree in Communications. I have
9 also completed all the coursework towards a PhD. in Economics from the
10 University of Utah. I have been working in electricity regulation for just over
11 3 years, first at the Committee of Consumer Services, and now at the Division.
12 Over this time I have worked on a variety of energy issues with my focus on
13 electrical issues. I have recently filed testimony before the Commission
14 regarding special contract rates and plant certification proceedings.

15

16 **Q. What is the purpose of this direct testimony?**

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

20

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

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

4

5 **Q. What do you believe the value should be?**

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

9

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

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

16

17	<u>Issue</u>	<u>Reduction</u>
18	1. Revision to Utah Load Forecast	\$28.5 million
19	2. CT Commitment and Quick Start Reserve	\$13.6 million
20	3. Revision to Forecast of System Losses	\$12.6 million
21	4. More Appropriate Regulation Amounts	\$8.5 million
22	5. Gadsby Steam Generation Too High	\$5.0 million
23	6. BPA Peaking Contract	\$3.3 million

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

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

14
15 **Q. Please describe the issue labeled as “Revision to Utah Load Forecast”**
16 **that accounts for approximately \$28.5 million of your proposed NPC**
17 **reduction.**

18 A. In his testimony on sales, Company witness Reed Davis showed a 5.9%
19 growth in Utah sales from the last year of actual data to the test year.
20 PacifiCorp corrected this growth rate in DPU 6.7 and DPU 9.47, however so
21 that in the test year as filed, Utah sales are projected to increase 9.6% over the
22 last year of actual, or almost twice as much as what was shown in Mr. Davis’
23 testimony. This is an increase of approximately 4.7% per year. The Division

1 believes that some change is necessary in this area. Specifically, the Division
2 does not agree with the abnormally high projections as compared to average
3 growth rates.

4 The historical Utah sales value shown in Exhibit DPU 7-1 is taken from
5 Data Request DPU 9.45. These data did not include sales for the period
6 ending March 2004, so those data were taken from Data Request DPU 9.47.
7 The data show that the five-year average annual growth rate for Utah sales is
8 3.0% and the most recent four years have an average annual growth rate of
9 1.7%. The growth rate used by PacifiCorp of 4.7% per year is considerably
10 higher than these figures. In order to develop a more historically consistent
11 estimate, the 5-year average growth rate of 3.0% was used. This reduced Utah
12 sales by 686,935 MWH. This becomes approximately 749,894 MWH when
13 losses are included using the same rate of losses as PacifiCorp used in its base
14 runs.

15 This adjustment reduces NPC by \$28,548,126 when run through GRID,
16 but may or may not decrease final rates due to fewer projected MWH over
17 which to allocate fixed costs. The Division realizes that the growth rate will
18 impact numerous other areas of the case including allocation and revenues;
19 preliminary examination indicates that revenues may decline by more than
20 \$35 million. A data request for the calculations necessary to complete the
21 overall adjustment has been issued to PacifiCorp and is outstanding. The
22 Division will complete this adjustment and file amended testimony upon
23 receipt of the necessary information from PacifiCorp.

1 **Q. Please describe the issue labeled as “CT Commitment and Quick Start**
2 **Reserve” that accounts for approximately \$13.6 million of your proposed**
3 **NPC reduction.**

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

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

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

1 **Q. Please describe the issue labeled as “Revision to Forecast of System**
2 **Losses” that accounts for approximately \$12.6 million of your proposed**
3 **NPC reduction.**

4 A. PacifiCorp claimed in DR DPU 11.7 to have used the value of 9.9329% for
5 total system losses, which includes line losses and transformer losses, as a
6 percent of total sales in its test year cost calculation. This rate is higher than
7 actual losses in recent years and the Division has not seen justification for
8 raising the rate above that experienced in the recent past. Losses over the last
9 five years, shown in Exhibit DPU 7-2, have fluctuated between approximately
10 8.7% and 9.9%, with a five-year average of 9.269%. This seems to be a small
11 difference, but when it is applied to over 50 million MWH in sales, using this
12 five-year average value reduces the GRID test-year energy requirements by
13 approximately 336,786 MWh and results in a reduction in NPC of
14 \$12,602,986.

15 Comparing forecasted sales with load in GRID shows that losses in GRID
16 are not what PacifiCorp claimed in its data response. Losses in GRID are
17 9.9999%. Adjusting this level of losses to the 5-year average would reduce
18 energy requirements by a further 33,299 MWH. This larger adjustment is
19 included in the calculation of the effect of overlapping issues.

20

21 **Q. Please describe the issue labeled as “More Appropriate Regulation**
22 **Amounts” that accounts for approximately \$8.5 million of your proposed**
23 **NPC reduction.**

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

18 Revised GRID runs were performed to attempt to correct this. The first
19 adjustment was to reduce the level of regulating reserves on the west side.
20 The west side is hydro heavy and therefore does not require many regulating
21 reserves beyond the level of spinning and non-spinning reserves already
22 required. Therefore, the DPU GRID modeling set a minimum and maximum
23 amount of regulation in the west at 0 MW and 50 MW, respectively. The

1 limits on regulation in the east were set to 0 MW and 125 MW (minimum and
2 maximum, respectively) and the transfer of reserves from west to east was
3 increased from 100 MW to 200MW. These changes were made in an attempt
4 to force GRID to more closely simulate actual CT generation and not because
5 these are the perfect way to model regulation.

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

11
12 **Q. Please describe the issue labeled as “Gadsby Steam Generation Too**
13 **High” that accounts for approximately \$5.0 million of your proposed**
14 **NPC reduction.**

15 A. The level of generation and costs for the Gadsby Steam units in GRID is much
16 higher than recent actual. GRID’s test year generation at the Gadsby steam
17 plant is approximately 70% or 111,200 MWH higher than generation for
18 calendar 2003. GRID’s generation for January through September is 228% or
19 154,377 MWH higher than actual generation for the January through
20 September period in 2004. Actual generation in these comparisons is
21 calculated from the hourly data in DR DPU 11.3b.

22

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

3 A. Yes. The addition of the Currant Creek combustion turbines means that the
4 Gadsby steam units would probably be needed even less than they were in
5 2003 and 2004. This further emphasizes that GRID's generation and cost for
6 the Gadsby steam plant are too high.

7
8 **Q. What are the reasons for the Gadsby steam plant's generation and cost in**
9 **GRID being too high?**

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

18 The second reason that GRID dispatches the Gadsby steam units at too
19 high a level is that GRID appears to ignore operations and maintenance costs
20 when making its commitment and dispatch decisions. The Gadsby steam
21 units have high O&M costs – total costs of the units were \$91/MWH
22 according to PacifiCorp's FERC Form 1. For most of PacifiCorp's units,
23 variable O&M costs are relatively small. Variable O&M appears to be an

1 important consideration for the Gadsby steam units, however. Therefore, since
2 GRID is dispatching the steam units more than in practice, GRID may not be
3 adequately accounting for variable O&M in making its dispatch decisions.
4

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

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

11 **Q. Please describe the issue labeled as “BPA Peaking Contract” that
12 accounts for approximately \$3.3 million of your proposed NPC reduction.**

13 A. PacifiCorp has a contract with the Bonneville Power Administration (BPA)
14 for BPA to provide capacity to PacifiCorp during the day and for PacifiCorp
15 to return the power at night. The contract is somewhat complex with many
16 specific details to be accounted for, such as the level of capacity, the specific
17 hours of take and return and the weekend operation. In the test year, the BPA
18 Peaking contract has a maximum take of 460 MW, so this is quite a large
19 contract.
20

21 **Q. How is this contract modeled in GRID?**

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

1 MW for a three hours, then reaches full capacity of 460 MW for a few hours
2 and then reverses the morning ramp up. This simple approach does not
3 match actual operation and does not achieve full value for the contract.
4

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

6 A. Greater value can be achieved by making the BPA “take” follow changes in
7 load more closely. This would also make the model results resemble actual
8 practice more closely. The BPA contract cannot follow load exactly, but since
9 load changes in a similar pattern each day in a season, the BPA contract can
10 and has followed load to a certain extent in actual practice.
11

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

14 A. GRID does not follow load closely with either hydro or the BPA peaking
15 contract. Therefore, GRID is following load with either the CTs or the coal
16 units. Hydro sources, either PacifiCorp’s own hydro generation or the BPA
17 peaking contract, are good units to follow load with. One reason that these are
18 good is that the hydro can ramp up and down very quickly. The second is that
19 hydro is typically less expensive to run than are any of the fossil fuel
20 resources.
21

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

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

6

7 **Q. Please describe the issue labeled as “Hydro Load Following” that**
8 **accounts for approximately \$3.0 million of your proposed NPC reduction.**

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

15

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

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

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

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

9
10 **Q. Please describe the issue labeled as “Weighting of Vista Hydro Scenarios”**
11 **that accounts for approximately \$1.5 million of your proposed NPC**
12 **reduction.**

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

22 Using weights developed from a normal distribution more closely matches
23 actual historical weather conditions and places more emphasis on the likely

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

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

11
12 **Q. Please describe the issue labeled as "Revision of CT Forced Outage Rate"**
13 **that accounts for approximately \$0.2 million of your proposed NPC**
14 **reduction.**

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

22 The DPU believes that a mere correction to PacifiCorp's arithmetic is not
23 the appropriate approach, however. The Gadsby and West Valley CTs will be

1 about four years old during the test year, which is roughly the time that units
2 transition to a mature FOR. It is inappropriate to use a FOR that places so
3 much weight on the CTs performance during the early years, when units
4 typically suffer higher FOR. Therefore, a DPU GRID run was performed
5 where the CTs' FOR was lowered to an estimate of a mature FOR of 4.2%.
6 Making this change resulted in a reduction in NPC of \$175,745.

7
8 **Q. Please describe the issue labeled as “Inclusion of New Wind Resources”**
9 **that accounts for approximately \$1.2 million of your proposed NPC**
10 **reduction.**

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

1 PacifiCorp's current GRID modeling does not include any additional
2 renewable energy projects from the Company's solicitation. This is unlikely
3 to be the case in reality. Arguably, given the current expiration of the PTC at
4 the end of 2005, it may make sense for PacifiCorp to advance its procurement
5 of renewable capacity from what was slated for later years. PacifiCorp stated
6 in DR DPU 16.20 that it intends to have 100 MW on line by the end of 2005,
7 but did not include it in its base GRID run because the contract had not been
8 finalized. They further state that they intend to include 100 MW of wind in
9 their rebuttal testimony. In subsequent discussion on December 1, 2004,
10 PacifiCorp indicated that wind will not be included in the GRID update.
11 Therefore, the DPU evaluated a case that assumes that the originally intended
12 100 MW of renewable resources would be added by October 1, 2005 and
13 provide 6 months of energy. The analysis included a wind project with a 30%
14 capacity factor added to the system with a price of \$35/MWh. The resulting
15 reduction was approximately \$1.2 million.

16
17 **Q. Do you have any other issues to address?**

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

21
22 **Q. Does this conclude your direct testimony?**

23 A. It does.