LAW OFFICES OF

RACINE OLSON NYE BUDGE & BAILEY
CHARTERED

201 EAST CENTER STREET
POST OFFICE BOX 1391
POCATELLO, IDAHO 83204-1391

TELEPHONE (208) 232-6101
FACSIMILE (208) 232-6109

www.racinelaw.net

SENDER'S E-MAIL ADDRESS: elo@racinelaw.net

W. MARCUS W. NYE
RANDALL C. BUDGE
JOHN A. BAILEY, JR.
JOHN R. GOODELL
JOHN B. INGELSTROM
DANIEL C. GREEN
BRENT O. ROCHE
KIRK B. HADLEY
FRED J. LEWIS
ERIC L. OLSEN
CONRAD J. AIKEN
RICHARD A. HEARN, M.D.
LANE V. ERICKSON
FREDERICK J. HAHN, III
DAVID E. ALEXANDER
PATRICK N. GEORGE
SCOTT J. SMITH
JOSHUA D. JOHNSON
STEPHEN J. MUHONEN
CANDICE M. MCHUGH
CAROL TIPPI VOLYN
BRENT L. WHITING
JONATHON S. BYINGTON
DAVE BAGLEY
THOMAS J. BUDGE
JONATHAN M. VOLYN
MARK A. SHAFFER
JASON E. FLAIG
FERRELL S. RYAN, III

BOISE OFFICE
101 SOUTH CAPITOL
BOULEVARD, SUITE 208
BOISE, IDAHO 83702
TELEPHONE: (208) 395-0011
FACSIMILE: (208) 433-0167

IDAHO FALLS OFFICE
477 SHOUP AVENUE
SUITE 107
POST OFFICE BOX 50698
IDAHO FALLS, ID 83405
TELEPHONE: (208) 528-6101
FACSIMILE: (208) 528-6109

ALL OFFICES TOLL FREE
(877) 232-6101

LOUIS F. RACINE (1917-2005)
WILLIAM D. OLSON, OF COUNSEL

October 14, 2010

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IDAHO PUBLIC
UTILITIES COMMISSION

HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 W. Washington
Boise, Idaho 83702

Re: Case No. PAC-E-10-07

Dear Ms. Jewell:

Enclosed for filing in the captioned matter, please find nine copies of the Idaho Irrigation Pumpers Association, Inc.'s Direct Testimony and Exhibits of Anthony J. Yankel, with one copy designated as a reporter's copy. We are also submitting a CD containing the testimony in MS Word format and testimony and exhibits in PDF format.

Sincerely,

Conrad J. Aiken for

ERIC L. OLSEN

ELO:rg
Enclosures
cc: Service List

ORIGINAL

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IDAHO PUBLIC
UTILITIES COMMISSION

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION) OF PACIFICORP DBA ROCKY MOUNTAIN) POWER FOR APPROVAL OF CHANGES TO) ITS ELECTRIC SERVICE SCHEDULES) _____)	CASE NO. PAC-E-10-07

IDAHO IRRIGATION PUMPERS ASSOCIATION, INC.

DIRECT TESTIMONY

OF

ANTHONY J. YANKEL

OCTOBER 14, 2010

1 Q. PLEASE STATE YOUR NAME, ADDRESS, AND EMPLOYMENT.

2

3 A. I am Anthony J. Yankel. I am President of Yankel and Associates, Inc. My

4 address is 29814 Lake Road, Bay Village, Ohio, 44140.

5

6 Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL

7 BACKGROUND AND PROFESSIONAL EXPERIENCE?

8

9 A. I received a Bachelor of Science Degree in Electrical Engineering from Carnegie

10 Institute of Technology in 1969 and a Master of Science Degree in Chemical Engineering from

11 the University of Idaho in 1972. From 1969 through 1972, I was employed by the Air

12 Correction Division of Universal Oil Products as a product design engineer. My chief

13 responsibilities were in the areas of design, start-up, and repair of new and existing product lines

14 for coal-fired power plants. From 1973 through 1977, I was employed by the Bureau of Air

15 Quality for the Idaho Department of Health & Welfare, Division of Environment. As Chief

16 Engineer of the Bureau, my responsibilities covered a wide range of investigative functions.

17 From 1978 through June 1979, I was employed as the Director of the Idaho Electrical Consumers

18 Office. In that capacity, I was responsible for all organizational and technical aspects of

19 advocating a variety of positions before various governmental bodies that represented the

20 interests of the consumers in the State of Idaho. From July 1979 through October 1980, I was a

21 partner in the firm of Yankel, Eddy, and Associates. Since that time, I have been in business for

22 myself. I am a registered Professional Engineer in the states of Ohio and Idaho. I have

23 presented testimony before the Federal Energy Regulatory Commission (FERC), as well as the

1 State Public Utility Commissions of Idaho, Montana, Ohio, Pennsylvania, Utah, and West
2 Virginia.
3
4 Q. ON WHOSE BEHALF ARE YOU TESTIFYING?
5
6 A. I am testifying on behalf of the Idaho Irrigation Pumpers Association (IIPA).
7
8 Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?
9
10 A. My testimony will address the Company's jurisdictional revenue requirement as it
11 is impacted by the level of test year weather normalized Irrigation sales used by the Company,
12 the inappropriate level of losses being assigned to Idaho, and the treatment of the benefits and
13 costs of the Irrigation Load Control Program as they impact Idaho. I also address the treatment
14 of the Load Growth Adjustment Rate in PacifiCorp's ECAM proceedings, when the actual usage
15 falls below that projected in the Company's GRID model in general rate cases, and the data used
16 by the Company to calculate the cost of service for the Irrigation customers.
17
18 Q. PLEASE SUMMARIZE YOUR TESTIMONY.
19
20 A. Aside from this introduction, my testimony is divided into five sections.
21 * The first section deals with the level of Irrigation sales that the Company used to
22 develop its 2010 forecasted test year revenues and revenue requirement. Although
23 PacifiCorp recognizes that the 2009 Irrigation sales were quite low because of "an

1 unusually wet spring", its weather normalization process does not address precipitation.
2 Using PacifiCorp's weather normalized Irrigation sales for the 11 years prior to 2009, it
3 can be projected that in 2010 that the weather normalized Irrigation sales should have
4 been 545,000 MWH (17.7%) higher than used in the Company's filing. The test year
5 Irrigation revenue as well as the Idaho Jurisdictional revenue would be increased $7
6 million if a realistic weather normalized Irrigation sales figure would have been used.
7 * The second section deals with the assignment of cost responsibility to the Idaho
8 jurisdiction based upon the energy allocation factor used for Idaho. This energy factor
9 is based upon the same forecast sales data as used to develop the Idaho revenue, but a
10 different (greater) set of losses is applied to these sales than is calculated in the
11 Company's loss study for Idaho. PacifiCorp uses something referred to as "Border
12 Load" to calculate Idaho's losses for jurisdictional allocation purposes. This Border
13 Load method effectively measures all losses that occur in Idaho. However, only 13%
14 of all of the electricity that enters the Idaho jurisdiction is consumed in Idaho, with the
15 rest of it simply passing through to non-Idaho customers. Idaho customers should not
16 be charged for losses associated with energy that is simply passing through Idaho to
17 serve others.
18 * The third section deals with the benefit that Idaho receives and the costs that it incurs as
19 a result of the Irrigation Load Control Program. I generally conclude that although the
20 Program is a major benefit to the system (provides a great savings for all system
21 customers), the Idaho customers are paying significantly more than the benefit that they
22 are receiving. I recommend that in the long term (by the next rate case) that this
23 program be treated more as a system benefit where the curtailments are "sold" to the

system at their true value. For purposes of this case, a more realistic reduction/credit should be given to Idaho in the Company's jurisdictional allocation model that reflects the actual curtailment that was available during the test year as opposed to the limited (lower) amount that was used in the Company's filing. Use of actual 2010 curtailment levels as opposed to levels lower that what were even available in 2009 results in a reduction of the revenue requirement by 2.5 million.

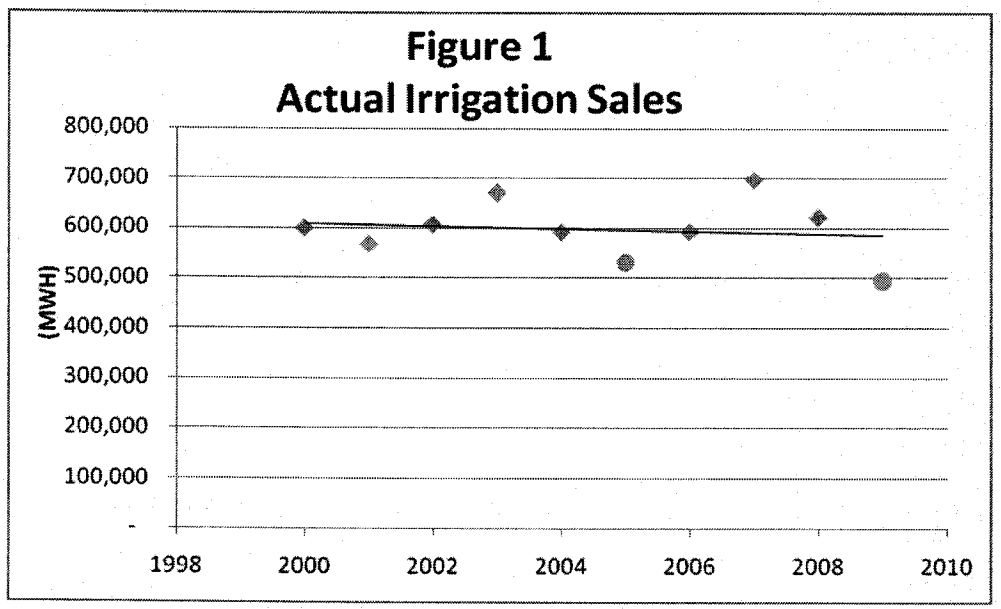
* The fourth section deals with the Load Growth Adjustment Rate ("LGAR") that is a part of the Company's ECAM proceeding, but the rate is set in this, a general rate case. The LGAR was originally established to keep the Company from double recovery of growth related power supply costs. An unforeseen problem has arisen with respect to the fact that it was never conceived that load would be decreasing as opposed to increasing between rate cases. Under such circumstances, the LGAR acts as a decoupling mechanism and actually increases rates when load is lost. My testimony recommends that the Commission specify that the LGAR is not a symmetrical adjustment and that it only is used when there is growth between rate cases.

* The fifth and last section of my testimony deals with the development of the class cost of service study. I point out that the Company's cost of service study (as was the jurisdictional model) does not have an adequate level of test year sales to the Irrigators. I also point out that the class cost of service study does not reflect the peak load reduction capability that is available, or even as used in the jurisdictional study. I do not present specific adjustments to this study, but simply recommend adoption of the Company's proposed increase to the Irrigators that is set at 70% of the jurisdictional average increase.

Irrigation Sales Level

Q. IS THE LEVEL OF TEST YEAR IRRIGATION SALES USED BY THE COMPANY APPROPRIATE?

A. No. Although the weather normalized value of 545,290 MWH for Idaho Irrigation sales[1] is claimed to be based upon test year number of customers, combined with sales per customer, and developed from regression analysis techniques using time trend variables;[2] a simple review of the historic data reveals that this level of usage is significantly below what would be considered a normalized test year value for the Irrigation customers. The actual sales levels to the Irrigation customers over the last 10 years were provided in the Company's Response to IIPA Request 87 and are graphically presented in Figure 1 below. Except for the 2005 and 2009 actual sales levels, the other recent annual sales to the Irrigation customers have been well in excess of the normalized value proposed in this case.



[1] At sales level which for the Irrigators is considered to be at secondary distribution level.

1 Q. WHY WERE IRRIGATION SALES SO LOW IN 2009?

2

3 A. The Company gave the following explanation in Mr. Eelkema's testimony at page

4 3, line 3:

5 Idaho's 2009 sales were unusual for at least two reasons. First, 2009 industrial
6 sales were abnormally low. Second, an unusually wet spring resulted in a
7 decrease in irrigation sales. The usage from these two customer classes decreased
8 approximately 20 to 21 percent from 2007 and 2008 levels, reducing Idaho's 2009
9 total sales approximately 12 to 13 percent from 2007 and 2008 levels. (Emphasis
10 added)

11 I fully concur with this explanation.

12

13 Q. IS IT APPROPRIATE TO SIMPLY RELY UPON ACTUAL HISTORICAL

14 SALES TO JUDGE THE VALIDITY OF THE COMPANY'S WEATHER NORMALIZED

15 VALUES?

16

17 A. Looking at actual data is a good starting point, but weather normalized data

18 should be reviewed as well. The Company provided its historic weather normalized sales per

19 customer data for the previous 12 years in its response to IIPA Request 22e. This historic

20 weather normalized sales per customer data was combined with the number of Irrigation

21 customers taken from the Company's Response to IIPA Request 84 and is graphically displayed

22 on Figure 2 below. There are two things to note: first, on a normalized basis there has been a

23 gradual, but steady increase in Irrigation sales since 1998; and second, the weather normalized

24 sales for 2009 is significantly below the trendline of all of the weather normalized data—it does

25 not fit. Remember—this data is on a "weather normalized" basis that should have removed all

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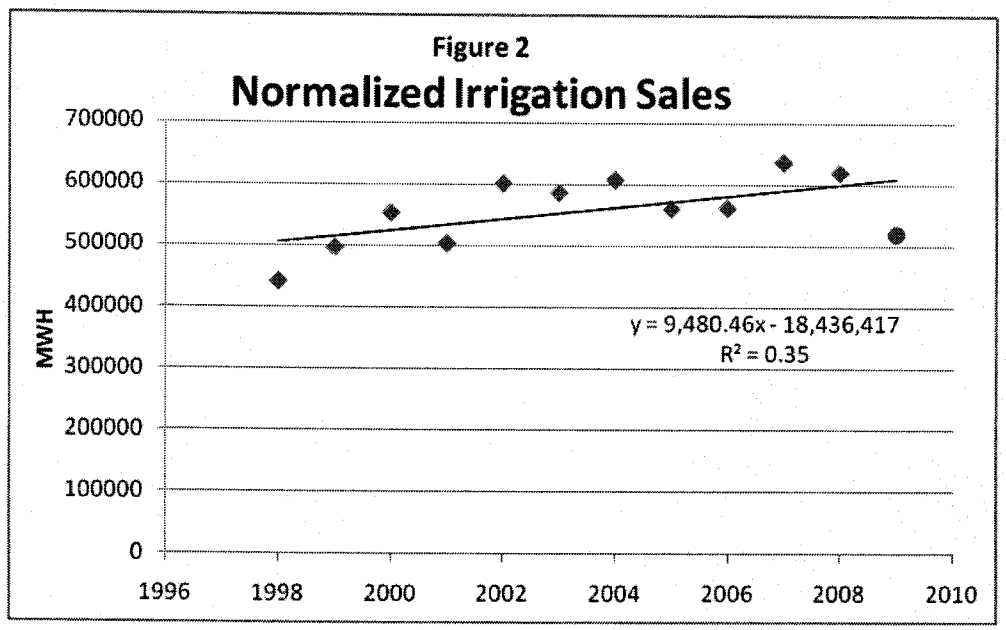
[2] See generally Eelkema's direct testimony page 5, line 11 through page 6 line 9.

1 impacts of different weather in different years. The Company's weather normalized 2009
2 Irrigation sales are clearly an outlier.



3
4
5 Q. WHY DOESN'T THE COMPANY'S WEATHER NORMALIZED DATA FOR
6 2009 FIT THE PATTERN SHOWN IN THE TRENDLINE IN FIGURE 2?
7
8 A. The reason that the weather normalized 2009 Irrigation sales data is so low and
9 not fitting the trendline can be simply traced back to Mr. Eelkema's statement that 2009
10 Irrigation sales were so low because of an unusually wet spring. In spite of this recognition, the
11 Company does not weather normalize Irrigation sales data for precipitation[3] thus, the unusually
12 low sales data in 2009 that was due to an unusually wet spring, was in fact not normalized for the
13 weather anomaly that occurred. In spite of the Company's testimony that the wet spring caused

[3] See Response to IIPA Request 22-f.

low Irrigation sales in 2009, its weather normalization procedures did nothing to take this situation into account.

Q. DOES IDAHO POWER WEATHER NORMALIZE ITS IRRIGATION SALES DATA FOR PRECIPITATION?

A. Yes. In support of its weather normalization adjustments used in Case No. IPC-E-03-13, Idaho Power supplied to the Commission Staff (in response to its Request No. 3) its supporting documentation for weather normalization. With respect to the regression models that Idaho Power ran for Irrigation sales, the following description was provided with respect to the Irrigation models for each of the Company's operating centers:

> The weather variables utilized by the system irrigation weather adjustment model are constructed as weighted averages of degree day variables from four service area weather stations: Boise, Twin Falls, Pocatello, and Ontario. That is, the growing degree day variable (cooling degree days Base 50) is an average of growing degree days from the four weather stations, each weighted by the share of total system irrigation pumping horsepower connected in the division associated with that weather station. The precipitation variable was constructed and weighted in the same manner. A second precipitation variable was used to measure the impact of pre-growing season precipitation on the early months of the growing season (May and June). This variable is zero for all months except May and June of each year where it is the total of the weighted precipitation for the two previous months. ...

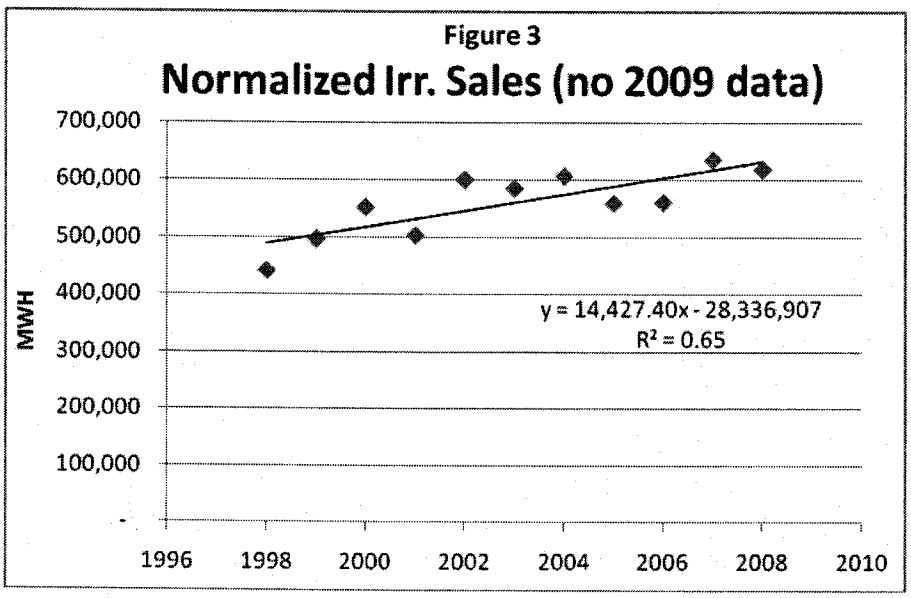
Thus, unlike PacifiCorp, Idaho Power's Irrigation weather normalization model not only recognized the impact of precipitation on Irrigation sales, but also recognizes a second precipitation variable that deals with the early growing season—precisely under the conditions where PacifiCorp noted abnormal precipitation and abnormally low sales. For this reason, even though PacifiCorp's weather normalized Irrigation sales for 2009—no adjustment was made to normalize for the "unusually wet spring".

Q. SHOULD PACIFICORP'S 2009 IRRIGATION SALES BE INCLUDED AND/OR USED IN THE GRAPH AND/OR ANALYSIS ABOVE?

A. No. As noted above, a review of the graph in Figure 2 reveals 2009 to be an outlier (even on a weather normalized basis) and the fact that PacifiCorp underwent an "unusually wet spring" without making normalization adjustments for precipitation indicates that this "normalized" value is wrong or simply meaningless.

Q. WHAT WOULD THIS GRAPH LOOK LIKE IF THE MEANINGLESS 2009 DATA WERE IGNORED?

A. The graph in Figure 3 below shows that the annual, normalized sales data is much more uniform with the 2009 data removed.



By removing one piece of obviously bad "normalized" data, the R-Square for this trendline is almost double that of the previous graph in Figure 2.

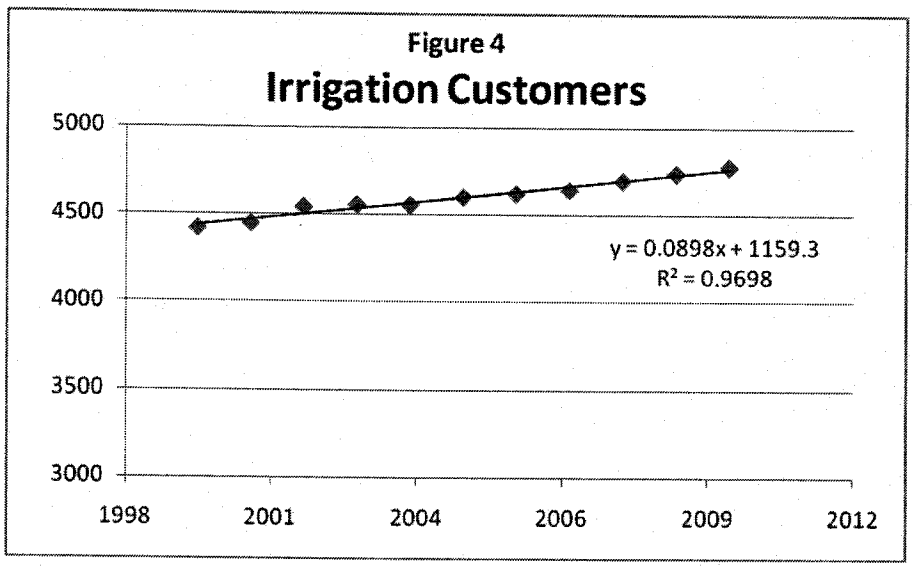
Q. THE NORMALIZED IRRIGATIONS SALES DATA IN FIGURES 2 AND 3 ARE INCREASING. IS THIS CONSISTENT WITH EXPECTATIONS?

A. Yes. First, it must be remembered that this data is PacifiCorp's own data and it reflects only Southeastern Idaho. Second, the data is based upon actual sales data that has been normalized to remove some of the obvious weather anomalies—the data is not based upon assumptions regarding anticipated changes in independent variables. Third, the increased sales data generally fits with the increase number of Irrigation customers that this region has experienced.

Q. HOW MANY NEW IRRIGATION CUSTOMERS HAS PACIFICORP ADDED IN ITS IDAHO SERVICE TERRITORY OVER THE LAST 10 YEARS?

A. During the last 10 years there has been an increase in the number of Irrigation customers in PacifiCorp's Idaho service territory of approximately 350 customers or 8%.[4] Figure 4 below depicts this growth over the last 10 years:

[4] Generally see the Response to IIPA "Request 84.



In spite of this well established relationship of the ever increasing average number of Irrigation customers over the last 10 years, the Company's test year average number of Irrigation customers is 11 customers less than what was realized in 2009.

Q. WHAT DOES THE ABOVE COMPANY WEATHER NORMALIZED IRRIGATION SALES DATA PREDICT WITH RESPECT TO THE 2009 AND TEST YEAR 2010 IRRIGATION SALES LOAD?

A. Based upon the trendline through the Company's weather normalized irrigation sales data in Figure 3, the normalized Irrigation sales in 2009 would have been 647,440 MWH compared to the actual Irrigation sales of 500,255 MWH.[5] The test year 2010 weather normalized Irrigation sales would be 662,167 MWH compared to the inappropriate level of 545,290 MWH used in the filing. Essentially, the Company used a value for Irrigation sales that

[5] See response to IIPA Request 18.

1 was 17.7%[6] less than what is predicted—similar to the general conclusion discussed on page 3 of
2 Mr. Eelkema's testimony:

3 ... usage from these two customer classes decreased approximately 20 to 21
4 percent from 2007 and 2008 levels
5

6 Q. ARE THERE OTHER INSTANCES WHERE THE COMPANY'S TEST YEAR
7 FORECAST SALES PRODUCE TOO LOW OF A RESULT?
8

9 A. I have only briefly looked at the Company's forecast test year sales for the
10 Residential class. The response to Staff Request 291 listed the actual (weather normalized) sales
11 for the Residential customers for the first six months of the test year as well as the forecasted
12 (weather normalized) sales as well. As can be seen on Exhibit 301, the forecasted sales for all
13 Residential customers for the first six months of the test year was 365,652 MWH, while the
14 actual sales (after weather normalization) was 388,066 MWH or 6.13% higher. Because both
15 figures are based upon "normal" weather, this deviation of 6.13% (since the case was put
16 together) is huge. The fact that both the Company's Irrigation model and its Residential model
17 are under-predicting sales by such large amounts raises concerns regarding the other sales data
18 used by the Company in this case.

19 Furthermore, even the number of forecasted Residential customers in the Company's test
20 year starts off below the number of Residential customers that were on the system at the end of
21 2009. Exhibit 302[7] lists the number of Residential customers for each of the 36 months for 2007
22 through 2009. Out of the 36 months listed on that exhibit, the number of Residential customers
23 increased in 32 of the 36 months. The average decrease that occurred during those other four

[6] 545,290 / 662,167 = 0.826

1 months was only 48 customers per month. There were 57,156 Residential customers in the
2 jurisdiction on December 2009, one month before the test year. By contrast, the number of
3 Residential customers forecast for January 2010[8] was 56,725 or 431 less than the actual number
4 of customers the month before. Once again, the Company's forecast of billing units, and thus
5 revenue, is coming up short.
6
7 Q. WHAT ADJUSTMENTS ARE YOU PROPOSING TO BRING THE
8 COMPANY'S TEST YEAR SALES LEVELS MORE IN LINE WITH "NORMAL" LEVELS?
9
10 A. Although the Residential sales data is clearly understated, I am only
11 recommending an adjustment to the Irrigation sales data. I am not making an adjustment to the
12 Residential sales because I have not reviewed it to the extent I have the Irrigation data—not
13 because I do not believe that an adjustment is necessary. I recommend that the Irrigation sales
14 data be increased by 116,877 MWH—the difference between what the trendline based upon the
15 Company's own weather normalized values over 11 years and the value used by the Company in
16 the development of its test year sales.
17 Although I am proposing to increase Irrigation sales by 116,877 MWH, I am not
18 proposing an increase in the billing kW, which is far more stable from year to year (in spite of
19 weather variation) and the Company's forecasted values generally look appropriate. By way of
20 comparison, recent annual billing kW are listed below as well as that used in the Company's test
21 year:[9]

---

[7] Based upon the Company's response to IPUC 20.
[8] See the Company's response to IPUC 292.
[9] See Response to IIPA Request 26.

Table 1

	Billing kW
2005	1,299,501
2006	1,365,546
2007	1,354,124
2008	1,325,036
2009	1,324,449
test year	1,346,186

Q. WHAT RATE SHOULD BE ASSIGNED TO THESE INCREASED IRRIGATION SALES?

A. Although Schedule 10 for Irrigation contains three different rate blocks during the Irrigation season and a separate rate block during the off-season, historical data demonstrates that the average "energy related" revenue collected each month is quite close (plus or minus) to the off-season energy rate. For that reason, I will simply use the off-season energy rate to establish the additional revenue that would be collected if the test year Irrigation sales were more properly established. I recommend that the 116,877 additional MWH of Irrigation sales be multiplied by 6.0315 cents/kWh in order to produce additional revenue of $7,049,436. The Irrigation test year revenue should thus be set at $46,895,173.

Q. HOW DOES YOUR PROPOSED TEST YEAR IRRIGATION REVENUE COMPARE WITH THAT COLLECTED HISTORICALLY?

A. The total Irrigation revenue of $46,895,173 compares quite favorably with that collected over the last several years—once the impact of recent rate increases is taken into account in order to put the historical revenues on the same basis as today's rates. The table

below lists the historic revenues, the level of increases to the Irrigation customers, and the effective revenue for each year at today's rates:

Table 2

	Actual	Rate Increases	Equivalent Revenue
2006	$37,795,154	1.70%	$40,329,167
2007	$45,193,746		$48,223,804
2008	$42,740,305	4.89%	$43,479,712
2009	$37,330,030	1.73%	$37,330,030
PacifiCorp			$39,845,737
Proposed			$46,895,173

It should be remembered that the above revenue figures are based upon actual usage and not weather normalized usage. The 2009 Irrigation season saw the lowest Irrigation sales for the most recent 12 years reviewed and thus, the revenues for that year would be expected to be unusually low. Likewise, normalized 2008 sales were slightly below the trendline and 2007 sales were above.

Q. WHAT WOULD HAVE THE ADJUSTMENT BEEN TO THE IRRIGATION SALES IF ALL 12 MONTHS OF HISTORICAL DATA WERE USED, INCLUDING THE IMPROPERLY NORMALIZED 2009 DATA?

A. Although the 2009 data is clearly too low and significantly under estimates Irrigation sales, using the trendline from Figure 2 above results in a predicted 2010 usage of 619,308 MWH which is 70,018 MWH above the value used by the Company as test year Irrigation sales. Valuing these additional sales at 6.0315 cents per kWh, the additional revenue that should be assigned to the jurisdiction is $4,223,136. Even using this inappropriate data that

1 does not take into account the "unusually wet spring" of 2009, results in the need for a
2 significant adjustment to the Company's filing.
3
4 Q. BECAUSE OF THE PROBLEMS WITH THE COMPANY'S FORECAST,
5 AND BECAUSE WE ARE NEARING THE END OF THE YEAR, WOULD IT BE MORE
6 APPROPRIATE IN THIS CASE TO SIMPLY SUBSTITUTE ACTUAL 2010 IRRIGATION
7 SALES AND REVENUES?
8
9 A. No. The Company cannot pick and choose where it wishes to normalize and
10 where it wishes to use actual data. Furthermore, it is my understanding that the 2010 Irrigation
11 season may have been similar to 2009—an unusually wet spring. Even if the Company's entire
12 filing had been on an actual (as opposed to a normalized) basis, standard ratemaking treatment
13 would dictate that such abnormal weather/sales would need to be normalized. The point is that
14 the data needs to be normalized, but the Company's proposed normalized Irrigation sales are
15 clearly inappropriately too low.
16
17 Q. HOW SHOULD THE PROPER NORMALIZATION OF THE IRRIGATION
18 LOAD BE TREATED IN THE COMPANY'S OVERALL REVENUE REQUIREMENT?
19
20 A. Both the increased Irrigation sales and revenue need to be incorporated into the
21 Company's jurisdictional allocation models (JAM and RAM). The increased test year Irrigation
22 revenue will decrease the revenue requirement in this case, but that will be somewhat offset by
23 the allocation of increased costs to Idaho because of the increased load. However, before I

1 calculate the impact of these adjustments, I need to address the overall amount of energy that is

2 assigned to Idaho in the jurisdictional allocation model.

3

Jurisdictional Sales vs. Jurisdictional Allocations

Q. DO THE COMPANY'S JURISDICTIONAL SALES AND THUS REVENUE PROPERLY REFLECT THE ENERGY RELATED COSTS THAT ARE ALLOCATED TO IDAHO ON A JURISDICTIONAL BASIS?

A. No. There is a significant difference between the amount of sales, and thus revenue, attributed to the Idaho jurisdiction and the amount of energy/kWh used to allocate costs to the Idaho jurisdiction. Specifically, there is 2.66% more energy/kWh responsibility attributed to Idaho in the jurisdictional allocation model than what is attributed to Idaho for the calculation of jurisdictional revenues.[10] The net effect is that more costs are being allocated to Idaho than are required to serve the Idaho load—Idaho is being asked to pay the cost of serving others.

Q. GENERALLY SPEAKING, WHAT IS THE CAUSE OF THIS DIFFERENCE IN THE AMOUNT OF SALES ASSOCIATED WITH THE REVENUE ATTRIBUTED TO IDAHO AND THE AMOUNT OF ENERGY USAGE ATTRIBUTED TO JURISDICTIONAL EXPENSES?

[10] Exhibit 2, Tab 1, page 1.3 lists the total Idaho normalized General Business test year revenue at $202,733,163. Exhibit 50 lists the present Idaho revenue at $202,733,000 associated with 3,325,872 MWH. Exhibit 49, Tab 5, page 14, line 10, lists test year sales (@sale level) as 3,325,873 MWH which is associated with 3,557,594 MWH on line 14 @ Input. By comparison, Exhibit 2, Tab 10, page 10.14 uses a load of 3,652,385 MWH to allocate costs to Idaho or 2.66% more usage (3,652,385 / 3,557,594) = 1.0266446) than the revenue that Idaho is given credit for.

A. The difference results from the use of two different methods of applying losses to the jurisdiction.[11] First, the Company has periodically conducted loss studies for each jurisdiction. The values from these loss studies are used in the Company's cost of service study and for other purposes. Exhibit 303 contains six pages—the summary page of the loss study for each of the states in which the Company operates.[12] Near the bottom right of each page are listed the "cum[m]ulative sales expansion factors" (loss factors) for each voltage level. Under the heading of "Energy" and under the column labeled "e" there is listed cumulative energy (as opposed to demand) losses at each voltage level. For example, page 1 of Exhibit 303 lists the following losses by voltage level for Idaho:

Table 3

	Expansion Factors	Percent Losses
Trans.	1.03605	3.605%
Primary	1.06475	6.475%
Secondary	1.10148	10.148%

What this data means is that a Transmission customer in Idaho is assigned a percentage loss of 3.605% or the Company has to generate 1.03605 MWH for each MWH that the customer consumes. Likewise, the Company must generate 1.10148 MWH for each MWH that is consumed by a Secondary customer.

Table 4 lists the various loss factors that the Company has calculated for each of the states in which it operates:

[11] Generally see Responses to IIPA Requests 130 and 133.
[12] Loss studies provided in Response to IIPA Request 45.

1

Table 4

	Idaho	Utah	Oregon	Wash.	Wyoming	Calif.
Trans.	3.605%	3.605%	3.605%	3.605%	3.605%	3.605%
Primary	6.475%	5.763%	5.771%	6.039%	5.594%	5.946%
Secondary	10.148%	8.757%	9.180%	8.822%	8.136%	9.848%

2

3 There are two things of interest regarding Table 4: 1) all Transmission losses are considered to
4 be equal (transmission, like generation, is a system function and transmission losses should be
5 equally shared by all jurisdictions); and 2) Idaho has the distinction of having the highest
6 percentage losses on the distribution system (primary and secondary) of any of the states.
7
8 Q. WHAT IS THE SECOND METHOD OF ASSIGNING LOSSES TO THE
9 VARIOUS JURISDICTIONS THAT RESULTS IN AN EXCESSIVE AMOUNT OF
10 RESPONSIBILITY BEING ASSIGNED TO IDAHO?
11
12 A. The assignment of jurisdictional cost responsibility starts with the same test year
13 sales figures as used to establish the jurisdictional test year revenue, but the losses assigned to
14 Idaho are based on a 5-year relationship between what is referenced as the "Border Load" to the
15 jurisdictional sales. The Border Load is simply calculated each hour by measuring the amount of
16 energy coming into the state, plus the amount generated in the state, less the amount leaving the
17 state. The losses are then calculated by comparing these Border Loads with the monthly or
18 annual sales that took place in the state.
19 This has the appearance of being quite straight forward and even highly accurate. A
20 review of the monthly losses calculated for each state demonstrates the fallacy of that perception.

1 Simply looking at the Idaho monthly losses in Table 5 below, there are four months (March,
2 June, August, and November) when the losses were negative and three months (July, September,
3 and October) with losses greater than 20%.

Table 5

2009	Utah	Idaho
January	6.5%	1.3%
February	7.7%	13.3%
March	3.6%	-0.4%
April	8.7%	8.2%
May	6.7%	11.2%
June	9.5%	-7.8%
July	1.3%	43.1%
August	8.7%	-10.9%
September	1.9%	27.7%
October	7.4%	22.1%
November	15.2%	-0.3%
December	2.5%	5.7%
Simple Average	6.64%	9.41%

4

5 Q. IS THE VARIATION IN LOSSES SHOWN IN TABLE 5 BECAUSE THE
6 DATA IS PRESENTED ON A MONTHLY BASIS THAT COULD REFLECT LARGE
7 CHANGES IN SOME LOADS FROM MONTH TO MONTH?
8
9 A. No. First, if that were the case, Utah's and Idaho's percentages would generally
10 track each other—they do not. Second, IIPA Request 4 sought information regarding hourly
11 load data by customer class to compare with the Border Load data. By assigning the loss factors
12 derived from the Company's loss studies to each class' hourly loads; it is possible to review how
13 the Border Load fluctuates with the actual hourly sales loads. By way of example, the following
14 hourly data from Friday September 4, 2009 demonstrates how variable the relationship between
15 the hourly Idaho loads and the Idaho Border Loads can be:

1

Table 6

Hour	Monsanto	NuWest	Distribution	Idaho Sales	Border Load	Delta	Percentage
16	22,716	12,241	281,823	316,780	415,713	98,934	31%
17	96,986	12,260	291,616	400,862	356,268	-44,594	-11%
18	104,001	12,171	281,756	397,928	422,909	24,980	6%
19	102,665	12,173	284,224	399,062	428,988	29,926	7%

2

3 Although the variation from month to month or hour to hour in the losses calculated on the basis
4 of Border Load is an obvious concern, the main concern at this point is the inappropriately high
5 level of losses that is being assigned to Idaho in this case.

6

7 Q. UPON WHAT BASIS CAN IT BE DETERMINED THAT USING BORDER
8 LOAD DATA ASSIGNS AN INAPPROPRIATE AMOUNT OF LOSSES TO IDAHO?

9

10 A. There are a couple of different ways to demonstrate this. As seen from the Table
11 4 above, Idaho has been calculated to have the highest percentage losses of any state with respect
12 to primary and secondary distribution. (Appropriately, all states have the same transmission loss
13 factor as transmission is a system function.) However, this does not mean that Idaho should have
14 the highest overall percentage of losses. By comparison to the other states, Idaho has a very high
15 percentage (45%) of its sales at the Transmission level where the percentage of loss is much
16 lower. Based upon the Company's loss study, combined with the test year loads, Idaho's losses
17 should only be 6.98%.[13] However, the Company's use of its Border Load data assigns 9.82%

[13] Company Exhibit 49, tab 5, page 14 lists total sales (at sales level) at 3,325,873 MWH and at input level at 3,557,873 MWH for an overall level of losses of 6.9756%.

1 losses to Idaho.[14] By comparison, the Company's loss study indicates that if all of Idaho's load
2 (including Monsanto) were at the secondary level, the overall losses should only be 10.148%--
3 almost the same as what is calculated by the Border Load.
4
5 Q. HOW ELSE CAN IT BE SHOWN HOW INAPPROPRIATE THE LOSSES
6 ASSIGNED TO IDAHO ARE?
7
8 A. From Table 5 it can be calculated that (relatively speaking) the losses assigned to
9 Idaho in 2009 under the Border Load method would be approximately 42% more than those
10 assigned to Utah.[15] As pointed out above, based upon the Company's loss study and the actual
11 test year usage in Idaho, the losses for Idaho would be 6.98%. Doing a similar analysis on the
12 test year usage data filed in the most recent general rate case in Utah, it can be calculated that the
13 overall Utah losses would be 8.08%.[16] Even though the Distribution losses in Utah are
14 calculated to be at a lower percentage than those in Idaho, Utah has only 8% of its sales at the
15 Transmission level where losses are the least, while Idaho sales are 45% at the Transmission
16 level. Thus, when combining the sales in Idaho with recognition of the voltage level at which
17 those sales take place, it becomes apparent that the overall losses attributed to Idaho should be
18 less than those attributed to Utah. However, the Border Load data suggests that the percentage
19 of losses in Idaho should be 42% greater than that found in Utah. The Border Loads are clearly
20 measuring something inappropriate.

---

[14] Compared to the sales level of 3,325,873 MWH, Company Exhibit 2, page 10.14 assigns 3,652,385 MWH at input to Idaho for an overall level of losses of 9.8173%.
[15] 9.4116% / 6.6399% = 1.417
[16] In Utah Docket 09-035-23 on Exhibit (CCP-3), Tab 5, page 16 the total test year sales level at input is listed as 23,161,564 MWH and on page 17 the total test year sales at sales level is listed at 21,430,490 MWH.

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Q. WHAT IS WRONG WITH THE BORDER LOADS THAT IS CAUSING AN INAPPROPRIATE AMOUNT OF COSTS TO BE ALLOCATED TO IDAHO?

A. Although the Border Load calculation has some degree of accuracy, the fact is that it is an inappropriate measure of the losses that should be assigned to Idaho. The Border Loads determine all losses that occur in Idaho, but all losses that occur should not necessarily be assigned to Idaho. Specifically, any losses that occur on the Transmission system are system losses and not Idaho losses in that they will have little, if anything, to do with Idaho load.

For example, in 2009 there were 12,715,000 MWH that entered the Idaho jurisdiction and 9,495,000 MWH that left (just went through) the jurisdiction.[1] The difference (Border Load) of 3,220,000 either went to Idaho sales customers or losses. Idaho sales were only 2,950,000 MWH which is only 23% of what entered Idaho. Based upon the Border Load calculation, this leaves 270,000 MWH for losses that occurred <u>in</u> Idaho, but not necessarily <u>for</u> Idaho. Those losses not only related to the 2,950,000 MWH of sales in Idaho, but the 9,495,000 MWH of energy that simply passed through Idaho on its way to non-jurisdictional customers.

The Company's loss studies appropriately assign to all states the same level/percentage of Transmission loss—the Border Load method simply assigns to Idaho any losses that happen to occur on the Transmission system in Idaho to Idaho.

Q. HOW SHOULD LOAD AND LOSSES BE ASSIGNED TO IDAHO IN THE JURISDICTIONAL ALLOCATION MODEL?

[1] See Response to IIPA Request 132.

1

2 A. Load should be assigned to Idaho using the same load/sales as used to set the test
3 year revenue requirement. Losses should be based upon the same losses that were calculated in
4 the Company's loss study and applied to the test year sales in Idaho.

5 Based upon the Company's filing there was 3,325,873 MWH sold in Idaho at the sales
6 level and this equates to 3,557,594 MWH at input. Previously, I recommended that 116,877
7 MWH at the sales level be added to reflect a more properly normalized Irrigation usage. Using
8 Company's 10.148% losses that are assigned to Idaho secondary sales, the losses associated with
9 this correction would add an additional 11,861 MWH.[18] Thus, the total energy that should be
10 used to assign costs to the Idaho jurisdiction should be 3,686,332 MWH.[19] This energy figure is
11 virtually the same as that used in the Company's filing, which did not include an appropriate
12 level of normalized Irrigation usage (3,652,385 MWH). Thus, I recommend increasing test year
13 energy by 33,947 MWH or 0.929% in order to reflect normalized Irrigation sales, but removing
14 excess losses assigned to Idaho.[20]

15 As the Company indicated in its testimony, it developed a test year set of monthly
16 coincident peaks and then adjusted those peaks in order to match the changes it made in test year
17 sales. In the same manner as was used by the Company, I recommend an increase in the
18 Company filed jurisdictional coincident peaks for Idaho by this same amount (0.929%).

19

20 Q. WHAT IS THE NET IMPACT OF THE CHANGE IN THE NORMALIZED
21 TEST YEAR SALES TO THE IRRIGATORS COMBINED WITH THE REDUCTION IN THE

---

[18] 116,877 x 0.10148 = 11,861.
[19] 3,557,594 + 116,877 + 11,861 = 3,686,332.
[20] 3,686,332 / 3,652,385 = 1.0092944.

1 EXCESSIVE LOSSES THAT WERE ASSIGNED TO IDAHO BECAUSE OF THE USE OF
2 BORDER LOAD DATA?
3
4 A. As pointed out above, the more appropriate normalization of test year Irrigation
5 usage/revenues results in an increase in Irrigation and jurisdictional revenues of $7 million. The
6 removal of the excess losses associated with the use of Border Load data almost entirely removes
7 the impact (Idaho energy and demand allocators) of the increase in the normalized Irrigation
8 data. The net impact is an increase of jurisdictional energy and demand allocation values by
9 0.929%. Using the company's JAM and RAM models with these new inputs results in the
10 Company's proposed rate increase of $27,697,872 being reduced by $5,394,641.
11

Irrigation Load Control Program

Q. HAS THE COMPANY'S IRRIGATION LOAD CONTROL PROGRAM BEEN SUCCESSFUL?

A. Yes, it has been very successful. As a matter of fact, given the size of the jurisdiction, it is probably the largest load control program in the country. The Company's 2009 report on the Irrigation Load Control Programs contains a number of interesting facts:

* There was a total of 258 MW (at sales level) of participation during the peak month of July 2009. Of this amount, 4 MW was on the Schedule Forward Program (Schedule 72) and 254 MW was on the Company Dispatch Option Program (Schedule 72A).[21]
* Only an average of 12.6 MW opted out of the curtailments during July 2009.[22]
* The benefit of the program is established to be $81.56/kW-yr at the sale level.[23]
* The all-in program costs (administration, field and equipment costs, and participation credits was established to be $41.34 per kW of participation.[24]
* The Company Dispatch Option Program (Schedule 72A) customers (that make up 98.5% of the participating load) are paid a credit (which is included in the all-in program costs) of $30 per kW.

[21] Schedule 72 & 72A Idaho Load Control Program (2009 Credit Rider Initiative Final Report), at 11.
[22] *Id.* at 8.
[23] *Id.* at 10. This is based upon only using a loss factor of 10.39%, which is the peak demand factor used for the Utah secondary system, not the 11.642% that the Company uses for Idaho.
[24] *Id.* at 16.

Q. WAS THE PARTICIPATION IN THE IDAHO IRRIGATION LOAD CONTROL PROGRAM DURING THE TEST YEAR SIMILAR TO THAT LISTED IN THE 2009 REPORT?

A. A report for the 2010 Irrigation season has not been produced as of this writing. According to preliminary reports,[25] the amount of participation grew in 2010 (the test year). The participation level (at sales) is believed to now be:

Table 7

2010	Avoided MW	At Input Avoided MW
June	261	291
July	282	315
Aug.	278	310

Weather conditions in 2010 were similar to those of 2009, so it is expected that the need for curtailments was below "normal" during 2010.

Q. ARE THE IRRIGATORS PAID THE FULL BENEFIT THAT IS REALIZED BY THE SYSTEM FROM THIS PROGRAM?

A. No, far from it. As pointed out above, the system benefit is calculated to be at least $81.56 per kW of Irrigation demand that participates in the program. The Dispatch Option customers are paid only $30 per kW as a credit. Another $11.34 per kW of cost is incurred in the

[25] See Response to IIPA Request 23-A.

1 operation of the program. This leaves $40.22 per kW[26] of benefit that is left to be shared by all
2 customers on the system.
3
4 Q. IS THE BENEFIT OF THE IDAHO IRRIGATION LOAD MANAGEMENT
5 PROGRAM PROPERLY CREDITED TO IDAHO AND THUS THE IDAHO IRRIGATORS?
6
7 A. No. It is a well recognized fact that all of the Company's customers, not just the
8 Idaho customers or the Idaho Irrigators, equally share in the benefit of the program. In fact, the
9 customers in Oregon, Utah, and the other states get even more than what would seem to be the
10 "system benefit" of $40.22 per kW that is above the cost of the program. This is because the
11 Irrigation Load Management Program is treated as a situs cost and not a system cost.
12 Generally speaking, the Company's jurisdictional cost allocation model has Idaho pay for
13 all costs associated with the Program (administrative and credit payments), but reduces the test
14 year coincident peak load to Idaho in recognition of the Irrigation Load Management Program as
15 follows:

Table 8

2010	Jurisdictional Credited MW
June	184
July	189
Aug.	182

16
17 Running these reductions through the Company's jurisdictional allocation models results in a net
18 reduction in revenue requirement of approximately $7.5 million dollars. This is approximately
19 the same as the $7.3 million of participation credits for which the Idaho jurisdiction is made

[26] $81.56 less $30.00 less $11.34 = $40.22

1 responsible for in the Company's situs assignment of these costs to Idaho.[27] Essentially, Idaho is
2 made "even" with respect to the participation credits that are paid to the Irrigators.
3 However, Idaho is also situs assigned all of the other costs of the program as well.
4 PacifiCorp Schedule 191 (Customer Efficiency Service Rate) has built into it $4,300,000 per
5 year of forecasted Irrigation Load Control administrative costs. These are costs that are not
6 being spread in any fashion to the other system customers.
7
8 Q. WHAT IS THE NET RESULT OF THIS SITUS TREATMENT WITH
9 RESPECT TO THE REST OF THE SYSTEM CUSTOMERS?
10
11 A. Based upon the benefit of $81.56/kW, and the credit that is given to Idaho in the
12 jurisdictional allocation model, all of the system customers essentially pay for the participation
13 credit of $30/kW, but they pay none of the administrative costs of the program. Essentially all of
14 the non-Idaho system customers are receiving a benefit of $51.56/kW,[28] while Idaho is picking
15 up all of the administrative costs and its share of the participation credit costs.
16
17 Q. ASIDE FROM THE INEQUITABLE SITUS TREATMENT OF THE IDAHO
18 IRRIGATION LOAD CONTROL PROGRAM COSTS, ARE THERE PROBLEMS WITH THE
19 MANNER IN WHICH THESE COSTS AND BENEFITS ARE ALLOCATED?
20
21 A. Yes. The benefit to Idaho, as passed through the jurisdictional model, is based
22 upon data that does not fully compensate Idaho for the reductions that are being offered. The

[27] See Company Exhibit 2, page 4.5
[28] $81.56 less $30.00 = $51.56

1 curtailment reductions used by the Company (as listed in Table 8 above) are based upon two
2 inappropriate assumptions. First, the starting point for the development of these figures is too
3 low. The Company used a starting point of 229 MW of curtailment for each of the three summer
4 months in the test year. In 2009, this value was exceeded during all three summer month. As
5 can be seen from Table 7 above, the anticipated participation level for each summer month of the
6 test year is 30—50 MW higher than this starting value. The second problem is that these levels
7 of "potential" curtailment are at the sales level and not at the input level—they need to be
8 increased by 11.642%--the demand loss factor used for secondary distribution in Idaho. The
9 appropriate level of potential curtailment is listed below on Table 9 as well as the same
10 coincident factor values used by the Company to come up with the ultimate reduction that should
11 be applied to the jurisdictional allocation model:

Table 9

2010	Irrigation Avoided MW	At Input Avoided MW	Coincident Factors	Curtailment Adjustment
June	261	291	80.20%	234
July	282	315	82.50%	260
Aug.	278	310	79.40%	246

12

13 Q. WHAT IMPACT IS THERE TO THE COMPANY'S REVENUE
14 REQUIREMENT OF USING ACTUAL 2010 POTENTIAL CURTAILMENT LOADS AND
15 LOSS FACTORS TO REFLECT LOAD AT INPUT?
16
17 A. By only reflecting 2010 potential curtailment load and incorporating loss factors,
18 the Company's revenue requirement in Idaho was decreased by $2,524,000.
19

Q. WHY HAD THE COMPANY LIMITED ITS POTENTIAL CURTAILMENT OF IRRIGATION LOAD TO ONLY 229 MW?

A. The reasons that the curtailment levels used were limited to 229 MW can be gleaned from the 2009 Idaho Irrigation Load Curtailment Report at page 18 where under "Dispatch considerations" it was stated in part:

- Idaho Engineering Area Planning is concerned that too much load is either removed from or added to the system in too narrow of a time-frame (causing voltage imbalances).
- Upon initiation of a dispatch event voltage spikes above <u>tolerances of existing substation and/or circuit protective equipment and systems.</u>
- Upon the conclusion of the dispatch event and loads are once again returned to their 'normal' position voltage drops below <u>tolerances of existing substation and/or circuit protective equipment and systems</u>.
- Currently <u>there is simply insufficient time delay in either substation and/or system circuitry</u> to accommodate the dramatic voltage changes. (Emphasis added)

These statements were followed up on page 18 of the 2009 Report with the following "Recommendations":

- Plenary discussions with RMP Area Planning (Idaho) has determined that a more intelligent stepping into and out-of dispatch events will correct the voltage spikes/sages currently occurring.
- <u>Changes to the dispatch protocol may be an effective strategy to delay additional capital investment in infrastructure assets</u>.
- Changing the dispatch protocol will require analysis of the RMP engineering database to determine geospatial load locations as well as coordination with growers.
- A changed dispatch protocol will require the available dispatch windows to be lengthened.
- The aforementioned changes have been preliminarily discussed with Idaho growers and with members of the Idaho Irrigators Pumpers' Association (IIPA).
- The IIPA is supportive of the requisite changes.
- This requirement will also necessitate a tariff modification.
- As soon as analysis can be concluded and a dispatch strategy designed the Company will provide details that will be (1) reviewed with the IIPA and (2) put forward the appropriate tariff changes to Schedule 72A for Commission consideration. (Emphasis added)

There are three points that can be gathered from the above discussion that was in the Company's 2009 Idaho Irrigation Load Curtailment Report: 1) Some, if not all of the problems could be addressed with distribution equipment upgrades; 2) The spacing out of the curtailments was believed to be an inexpensive solution to the problem; and 3) The Company planned to make changes in its dispatching of curtailments during 2010.

As pointed out earlier in this testimony, Idaho has the highest Distribution loss factors of any of the states in which PacifiCorp operates. Additional expenditures to modernize the Idaho Distribution equipment may be a good idea and is not necessarily something to be avoided.

From my review of the Company's 2009 load research data associated with the Irrigators it would appear that the curtailments of the Irrigation customers had already been spread out to some extent. We have not heard the results of the further spreading out of these curtailments during 2010 and do not expect to hear until the 2010 Report is filed.

The Company filed this general rate case with the 229 MW limitation on curtailments before the 2010 Irrigation season even began and before it had tried its new dispatching protocol. Furthermore, the Company added additional curtailable load in 2010, which presumably the Company felt that it could accommodate.

Based upon all of the above, there is no reason in this general rate case to limit the credit calculated for the Idaho jurisdiction to a potential curtailment of just 229 MW.

Q. IN THE LONG TERM, WHAT DO YOU PROPOSE BE DONE IN ORDER TO EQUITABLY ALLOCATE SYSTEM COSTS AND SYSTEM BENEFITS OF THE IDAHO IRRIGATION LOAD CONTROL PROGRAM?

A. Not all load management programs are equal. It makes sense to have the same treatment for all programs, but that treatment should not be as archaic as the present method where most of the benefits of a program are essentially spread to the system, while all the costs are absorbed by the host jurisdiction. If a jurisdiction is going to absorb all of the costs of a direct load control program, then that jurisdiction should also be assigned all of the benefits of that program. In this manner, if the program has benefit beyond its cost, then the net benefit would be realized by the host jurisdiction. If the program has little or no net benefit, then the host jurisdiction will bear the consequences.

This allocation of benefits could simply be done by "selling" reductions to the system at the avoided cost—presently calculated to be $81.56/kW-year at the sales level. In the case of the Idaho Irrigation Load Control Program, Idaho would be responsible for the approximate $41.34/kW of all-in costs, and there would be no "reduction" in coincident demand calculated as a result of the program—the allocations would impute a value for any curtailments that took place during the monthly system coincident peaks. The difference between the $81 "sale price" and the $41 cost would go to reduce Idaho's revenue requirement.

Q. CAN YOU GIVE A SIMPLIFIED EXAMPLE OF HOW THIS WOULD WORK?

A. Yes. Assuming that there are 300 MW of Irrigation load signed up for Schedule 72A's dispatchable load control program, this could be "sold" to PacifiCorp for $81.56/kW or a total of $24,500,000 (300,000 kW times $81.56). This would be treated as a purchase power cost and allocated to all jurisdictions on a demand basis. Idaho would be responsible for

approximately 5.22% of this cost, based upon the System Capacity allocation factor. Idaho would thus pay approximately $1.3 million associated with this "purchase". Idaho would also absorb the $9.0 million associated with the credit paid to the Irrigators (300,000 kW time $30/kW). Idaho would also pay the administrative cost of the program which it is now paying of $4.3 million through Schedule 191. Idaho would pay $14.6 million (1.3 + 9.0 + 4.3 = 14.6), but would be given a credit of 24.5 million as a credit against its jurisdictional revenue requirement. Thus, instead of the program costing Idaho approximately $4.3 million per year, it would benefit by $9.9 million and all of the other jurisdictions would simply be kept neutral.

Q. WOULD UTAH'S COOL KEEPER AND IRRIGATION LOAD CONTROL PROGRAMS BE TREATED IN THE SAME MANNER?

A. Yes. However, care would need to be taken to insure that the costs of the programs are calculated in a manner similar to that being done for the Idaho Irrigation Load Control Program. Such an analysis for Utah's programs has not been done, so the Company's present treatment in Utah (Situs treatment of costs and assignment of demand reduction) should continue until such time as either the Utah Jurisdiction or the Company wish to put forth the information upon which to make such a change. If the Utah Cool Keeper program is not cost effective, Utah may desire to keep the present treatment.

The Load Growth Adjustment Rate in the Energy Cost Adjustment Mechanism

Q. PLEASE DESCRIBE THE ENERGY COST ADJUSTMENT MECHANISM AND LOAD GROWTH ADJUSTMENT RATE AS THEY RELATE TO THIS CASE.

A. The Energy Cost Adjustment Mechanism ("ECAM") is designed to recover on an actual basis the sum of all components of net power supply costs as defined in a general rate case such as this. The mechanism does not address fixed-cost recovery such as the fixed costs of investment in rate base. Basically, the ECAM only considers the variable power supply costs that are modeled in GRID and compares them with the actual costs incurred.

In addition to comparing actual net power costs to those modeled by GRID in a general rate case, the ECAM includes some additional components such as the Load Growth Adjustment Rate ("LGAR"). The theory behind the LGAR is that the Company should not be allowed to collect growth-related power supply costs through an ECAM surcharge and also collect base revenues from the new load to recover those same power supply costs.

Q. WHAT PROBLEMS ARE BEING ENCOUNTERED WITH RESPECT TO THE LGAR?

A. PacifiCorp has had an ECAM and thus an LGAR for only a short period of time. However, the Commission has had a great deal of experience with an ECAM type mechanism and an LGAR as they relate to Idaho Power. Unfortunately, due to the recent economic recession and possible other causes, the LGAR for both companies has not worked as intended.

1 The LGAR was intended to off-set the double recovery of growth related costs in both base rates
2 and the ECAM. Although the mechanism works well as intended for growth, it produces
3 unintended consequences under conditions of load decline—something that it was never
4 designed to address. In the case of load decline, the LGAR adjustment does not reflect costs that
5 were incurred by Company but, it represents costs that were never incurred. If allowed to
6 operate during times of load loss, as well as load growth, this adjustment would give the
7 Company revenue to cover costs that were never incurred. Such a result is unquestionably unjust
8 and unreasonable. Essentially, under these conditions, the LGAR operates as a decoupling
9 mechanism that was never approved by the Commission.
10
11 Q. PLEASE EXPLAIN FURTHER.
12
13 A. The entire concept of the ECAM was to recover variations in actual power
14 supply expenses that differ from test year calculations—the emphasis here should be on
15 actual power supply expenses. The ECAM itself was meant to be "symmetrical" in that it
16 was designed to give the Company more money/revenue when its power supply expenses
17 went up (compared to test year) and less money/revenue when its power supply expenses
18 went down (compared to test year). However, this symmetry was only in relationship to
19 the power supply expenses themselves, not to the LGAR.
20 It is appropriate in a pass-through mechanism such as the ECAM, that the
21 consumers pay more when expenses go up, but it makes no sense to raise rates when
22 usage, and thus costs, go down. When rates go up as usage goes down, a decoupling
23 mechanism is in effect—not a pass-through. The Commission has not authorized a

1 decoupling mechanism. It is appropriate that the load growth adjustment offsets to some
2 extent the amount of money that the Company gets in its ECAM to reflect the increased
3 base revenue that PacifiCorp gets associated with additional load. However, it makes no
4 sense to increase the revenue that PacifiCorp gets in the ECAM because of loss of load
5 when expenses are reduced.
6
7 Q. WHAT IS THE REASON FOR THE LGAR IN PACIFICORP'S ECAM?
8
9 A. Very simply, it is to prevent the double recovery of a single cost. It
10 prevents the Company from collecting growth related power supply expenses through the
11 ECAM that are also being collected in base revenue from new/increased load to cover the
12 same power supply expenses. The concern here is in the case where the growth has not
13 occurred, the cost of growth has not occurred, and there have been no additional power
14 supply expenses that were incurred. Why should the LGAR increase the ECAM revenue
15 for growth, and costs of growth, that never occurred? Clearly the collection of an
16 expense that never occurred is against all principles of fairness, let alone the
17 Commission's statutory responsibility.
18
19 Q. SHOULD THE LGAR BE SYMMETRICAL?
20
21 A. Although the ECAM was designed to be symmetrical, the LGAR should
22 not. It is appropriate that the ECAM increase or decrease as the Company's power
23 supply expenses increase or decrease. However, when the power supply expenses

1 decrease because the load has dropped, the LGAR should never be increased to make up
2 for expenses that were never incurred. The LGAR was never meant to be symmetrical
3 and it does not make sense that it should be symmetrical. Because of the sustained
4 growth that PacifiCorp and Idaho Power have experienced over the last 20-30 years, the
5 idea of a load decrease was far from everyone's mind when the LGAR was created.
6 Even the name of the LGAR (Load Growth Adjustment Rate) demonstrates that this is a
7 one-way adjustment related to growth. If it had been conceived of as a symmetrical
8 adjustment, it would have been more properly called an "Adjustment Rate for Load
9 Changes".
10 There are numerous places in Commission Orders as well as in testimony
11 presented before the Commission that demonstrate that the intent of the LGAR was to
12 address the issue of increased power supply expenses due to growth and the offsetting
13 additional revenue that comes with new load. There has never been mentioned in a
14 Commission Order of the intent of the LGAR (in PacifiCorp's or Idaho Power's cases) to
15 reflect any type of adjustment for a reduction in system load, let alone to be an
16 adjustment to increase the Company's revenues when loads decreased.
17 More specifically, the LGAR was designed to insure that there was no double
18 recovery of the additional power supply expenses that result due to growth. There are no
19 "additional" power supply expenses associated with a reduction in load—simply, less
20 coal is burned, there is less power purchased, or there are more sales for resale that brings
21 in additional revenue.

The design of the LGAR/EARG[29] to insure that there was no double recovery of additional power supply expenses as a result of load growth was summarized by Staff witness Hessing in Idaho Power Case No. IPC-E-06-8[30]:

> Q. Please discuss Idaho Power Company's initial PCA filing.
> A. Idaho Power Company filed for a PCA in 1992 and it was approved and implemented in 1993 with some modifications. Idaho Power's 1992 filing was made to address the problem of fluctuating water conditions that caused widely varying power supply costs. When water conditions were poor, power supply costs were higher than what was authorized for recovery in rates. A general rate case provided no relief from high power supply costs associated with below normal water conditions since water conditions and power supply costs are normalized in a general rate case.
>
> Staff observed that in the Company's original PCA proposal, variations from the normalized costs of power supply were due to water conditions <u>and power supply cost increases caused by load growth.</u> Staff believed that load growth costs could be significant and that load growth costs were not the kind of costs that the PCA should recover. Staff proposed a load growth adjustment mechanism in the PCA that removed actual power supply costs associated with load growth by multiplying the amount of load growth by the marginal cost of power supply and subtracting the result from actual power supply costs. Staff approximated the marginal cost of power supply as 16.84 $/MWh which was the average of the variable costs of Valmy and Boardman, the company's two highest operating costs at that time. <u>In that case Staff also argued that without the adjustment the Company would double recover the normalized cost of power supply because it was included in base rates and in actual booked power supply costs that accumulated in the PCA true up mechanism</u>. (Emphasis Added)

The testimony of Staff in Case No. IPC-E-06-8 that the LGAR/EARG was designed to prevent double recovery of power supply expenses did not stand on its own, but was fully supported by the Company testimony in that same case. Idaho Power witness Said made numerous references to the fact that the LGAR/EARG was designed to prevent the

[29] In PacifiCorp ECAM cases this "growth adjustment" is known as an LGAR, while in Idaho Power PCA cases the "growth adjustment" is known as an Expense Adjustment Rate for Growth ("EARG").
[30] See Hessing's direct testimony in Case No. IPC-E-06-8 page 4, beginning on line 9.

1 double recovery of growth related power supply expenses in his Rebuttal testimony in
2 that same case:[31]

> 3 Adoption of an adjustment mechanism based on expenses levels created
> 4 the potential for double collection of power supply expenses from
> 5 customers. Idaho Power believes that the intent of the load growth
> 6 adjustment rate was to eliminate the possibility of double collection of
> 7 power supply expenses.
>
> 8 Q. Do the other witnesses in this case agree that eliminating the
> 9 possibility of double collection of power supply expenses from customers
> 10 has been a historical intent of the load growth adjustment rate?
>
> 11 A. Yes. ...

12 Later in his testimony in that same case, Idaho Power witness Said summarizes his
13 testimony and makes an even stronger case for the Company's position/belief that the
14 LGAR/EARG is only for purposes of preventing the Company from double recovering
15 growth related power supply expenses:[32]

> 16 Q. Please summarize your rebuttal testimony.
>
> 17 A. All parties agree that a principal purpose of the PCA load growth
> 18 adjustment rate is to eliminate the potential for double recovery of power
> 19 supply expenses. <u>Idaho Power believes this should be the sole purpose of</u>
> 20 <u>the load growth adjustment.</u> (Emphasis added)

21

22 Mr. Said made it very clear what Idaho Power felt was the "sole purpose" of the
23 LGAR/EARG. However, because of a quirk in the calculation, that became evident as a
24 result of a severe global economic crisis, both PacifiCorp and Idaho Power have now
25 used the LGAR and the EARG to collect revenue for expenses that never occurred.
26 Given the steady growth that has taken place over the last 20-30 years, there had
27 been virtually no consideration of what happens when growth is negative. Like Idaho
28 Power witness Mr. Said testified, the sole purpose of the growth adjustment was to insure

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[31] See Said's Rebuttal testimony in Case No. IPC-E-06-8 page 3, beginning on line 6.
[32] See Said's Rebuttal testimony in Case No. IPC-E-06-8 page 27, beginning on line 11.

that there was no double recovery of power supply expenses when there was positive growth (as occurred every year in the past). However, even though there was little or no consideration of the possibility of what the LGAR calculation would produce if there was a decrease in load, the thought that the LGAR could ever produce a negative result was rejected by the Commission Staff. In Case IPC-E-07-8, Staff witness Hessing made such a declaration that was never challenged by any party in that case, including Idaho Power. Staff witness Hessing stated on page 18 line 14 of his direct testimony that: "It is not reasonable to apply a negative EARG in the PCA."

Q. WHAT ARE YOU RECOMMENDING IN THIS CASE REGARDING THE LGAR?

A. I am not addressing the level or dollar amount of the LGAR. I am only addressing the use of the LGAR in situations where load is declining—such situations that are just the opposite of the LGAR's intended purpose. In both the recent PacifiCorp ECAM case and an Idaho Power PCA case, negative growth has been encountered and for lack of direction or for whatever reason, the LGAR has been allowed to effectively operate as a decoupling mechanism and increase rates in the face of reduced sales. I recommend that in this case when the Commission sets the LGAR rate, that the Commission state very clearly that the LGAR is only to be applied in cases where there has been growth on the system compared to sales levels used in the general rate case to develop the net power costs that will be included in rates.

Class Cost of Service

Q. WHAT DOES THE COMPANY'S COST OF SERVICE STUDY INDICATE ABOUT THE RATE OF RETURN BEING SUPPLIED BY THE IRRIGATORS?

A. The Company's cost of service study calculates that the Irrigators are providing a rate of return that is 20% greater than the system average.[33] Based upon this, the Company is proposing that the Irrigators only get 70% of the average rate increase that will be adopted.[34]

Q. IS THE COMPANY'S COST OF SERVICE STUDY WITH RESPECT TO THE IRRIGATORS BASED UPON APPROPRIATE INFORMATION?

A. No, the Company's cost of service study suffers from two major flaws with respect to the Irrigators: 1) as pointed out above, the normalized sales levels used are grossly inadequate and understate the amount of Irrigation sales and thus revenues; and 2) the Company's method of developing sales over a 5-year average results in effectively giving Irrigators virtually no recognition in the cost of service study for any curtailment associated with the load management program.

Q. PLEASE DESCRIBE THE SHORTCOMING WITH RESPECT TO THE IRRIGATION SALES LEVELS FURTHER.

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[33] See generally Company Exhibit 49, Tabs 4 and 4.1

1

2 A. As pointed out above with respect to the jurisdictional revenue requirement, the
3 test year "weather normalized" Irrigation sales were significantly below the normalized values
4 that have been seen over the last ten years, as well as falling short of the slightly increasing trend
5 in normalized Irrigation sales over time. Adjusting the test year sales to a more realistic level
6 would increase Irrigation revenues by $7 million, while only increasing energy/variable related
7 costs and not fixed demand or customer related costs. As such, an increase in sales would result
8 in a significant increase in Irrigation revenue that would be larger than the associated increase in
9 expenses. Thus, these increased sales would increase the Irrigation rate of return, well in excess
10 of what the Company calculated.

11

12 Q. PLEASE DESCRIBE FURTHER THE SHORTCOMING WITH RESPECT TO
13 THE LACK OF RECOGNITION OF THE IMPACT OF THE CURTAILMENT OF
14 IRRIGATION LOAD THAT IS TAKING PLACE.

15

16 A. Earlier I pointed out that the Company's jurisdictional model did not give
17 full credit to the Idaho jurisdiction for the level of curtailment that took place with respect
18 to the Irrigation Load Control Program. However, the Company at least reduced the
19 Idaho summer jurisdictional peaks by 184, 189, and 182 MW each. Unlike these
20 reductions (that were inadequate), there was no such recognition of any curtailment of the
21 Irrigation load in the Company's class cost of service study. This is in spite of the fact

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[34] See Griffith direct testimony at page 2

that the same 5-year average Irrigation load was used for both the class cost of service study and the jurisdictional model.

Q. ARE YOU PROPOSING ANY SPECIFIC CHANGES TO THE COMPANY'S COST OF SERVICE STUDY TO CORRECT THESE SHORTCOMINGS?

A. Not at this time. I provide these observations in order to inform the Commission that the rate of return calculated by the Company for the Irrigation class is severely understated and that the actual rate of return for the Irrigators is much higher than calculated by the Company.

Because I am not proposing specific adjustments at this time to the Company's cost-of-service study, I am accepting (for now) the Company proposal to limit the rate increase to the Irrigators to the 70% of system average as proposed by the Company. Assuming no other party advocates for an increase greater than 70% of the system average for the Irrigation customer, I will not propose any further adjustments in this case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Forecasted Weather Normalized Residential Sales
vs.
Actual Weather Normalized Residential Sales

Forecast--weather normalized

Year	Month	Schedule 1	Schedule 36	Schedule 135	Schedule 7	Schedule 7AR	
2010	1	45,756	35,828	100	1	9	
2010	2	38,666	29,889	95	1	8	
2010	3	38,601	28,320	93	1	9	
2010	4	32,533	22,652	83	1	9	
2010	5	30,004	18,579	85	1	10	
2010	6	28,661	15,561	88	1	10	365,652

Actual--weather normalized

Year	Month						
2010	1	50,577	39,805	109	1	9	
2010	2	42,392	32,608	105	1	9	
2010	3	38,138	28,583	85	1	9	
2010	4	33,892	24,666	74	1	9	
2010	5	29,242	19,428	74	1	9	
2010	6	29,818	18,348	65	1	9	388,066

Delta

Year	Month						
2010	1	4,821	3,977	9	0	1	
2010	2	3,726	2,719	11	0	1	
2010	3	(463)	263	(9)	0	(0)	
2010	4	1,360	2,014	(9)	0	(0)	
2010	5	(762)	849	(12)	(0)	(1)	
2010	6	1,157	2,787	(23)	(0)	(1)	22,414
							6.13%

Source:

Attachment IPUC Production 291

Exibit No. 301
Case No. PAC-E-10-07
Yankel, Irrigators

Change in Residential Customers

Yearmonth	Number of Customers Billed	Delta
200701	54,556	
200702	54,663	107
200703	54,721	58
200704	54,842	121
200705	54,902	60
200706	54,985	83
200707	55,237	252
200708	55,259	22
200709	55,426	167
200710	55,539	113
200711	55,820	281
200712	55,925	105
200801	55,946	21
200802	56,000	54
200803	56,088	88
200804	56,089	1
200805	56,148	59
200806	56,154	6
200807	56,321	167
200808	56,376	55
200809	56,488	112
200810	56,578	90
200811	56,706	128
200812	56,805	99
200901	56,745	(60)
200902	56,844	99
200903	56,780	(64)
200904	56,733	(47)
200905	56,739	6
200906	56,807	68
200907	56,908	101
200908	56,887	(21)
200909	56,947	60
200910	57,039	92
200911	57,130	91
200912	57,156	26

Source:
Attachment IPUC 20

Exhibit No. 302
Case No. PAC-E-10-07
Yankel, Irrigators

PACIFICORP IDAHO 2007 LOSS ANALYSIS

PACIFICORP IDAHO REVISED

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		700	MW
GENERATION & PURCHASES-INPUT		3,735,483	MWH
ANNUAL SALES	-OUTPUT	3,485,834	MWH
SYSTEM LOSSES	INPUT	249,649	or 6.68%
	OUTPUT		or 7.16%
SYSTEM LOAD FACTOR		61.0%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	33.2	4.74%	59.89%	129,983	3.48%	52.07%
PRIMARY	69,34,12,1	12.7	1.82%	22.97%	55,144	1.48%	22.09%
SECONDARY		9.5	1.36%	17.14%	64,522	1.73%	25.85%
TOTAL		55.4	7.91%	100.00%	249,649	6.68%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08644	0.92043	1.06475	0.93919
SECONDARY		1.11642	0.89572	1.10148	0.90787

PACIFICORP UTAH 2007 LOSS ANALYSIS

PACIFICORP UTAH REVISED

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		4,373	MW
GENERATION & PURCHASES-INPUT		24,246,948	MWH
ANNUAL SALES	-OUTPUT	22,631,375	MWH
SYSTEM LOSSES	INPUT	1,615,573	or 6.66%
	OUTPUT		or 7.14%
SYSTEM LOAD FACTOR		63.3%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	207.3		59.45%	843,718		52.22%
			4.74%			3.48%	
PRIMARY	69,34,12,1	75.6		21.69%	343,266		21.25%
			1.73%			1.42%	
SECONDARY		65.8		18.86%	428,589		26.53%
			1.50%			1.77%	
TOTAL		348.6		100.00%	1,615,573		100.00%
			7.97%			6.66%	

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.07706	0.92846	1.05763	0.94551
SECONDARY		1.10349	0.90621	1.08757	0.91948

PACIFICORP OREGON 2007 LOSS ANALYSIS

PACIFICORP OREGON REVISED

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		2,598	MW
GENERATION & PURCHASES-INPUT		15,300,810	MWH
ANNUAL SALES	-OUTPUT	14,120,569	MWH
SYSTEM LOSSES	INPUT	1,180,240	or 7.71%
	OUTPUT		or 8.36%
SYSTEM LOAD FACTOR		67.2%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW	% TOTAL	MWH	% TOTAL
TRANS	345,161,115	123.1	49.92%	532,420	45.11%
		4.74%		3.48%	
PRIMARY	69,34,12,1	70.2	28.48%	288,840	24.47%
		2.70%		1.89%	
SECONDARY		53.3	21.61%	358,980	30.42%
		2.05%		2.35%	
TOTAL		246.7	100.00%	1,180,240	100.00%
		9.50%		7.71%	

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08191	0.92430	1.05771	0.94544
SECONDARY		1.11306	0.89842	1.09180	0.91592

PACIFICORP WASHINGTON 2007 LOSS ANALYSIS

PACIFICORP WASHINGTON REVISED

EXHIBIT

SUMMARY OF COMPANY DATA

ANNUAL PEAK		753	MW
GENERATION & PURCHASES-INPUT		4,435,907	MWH
ANNUAL SALES	-OUTPUT	4,090,955	MWH
SYSTEM LOSSES	INPUT	344,952	or 7.78%
	OUTPUT		or 8.43%
SYSTEM LOAD FACTOR		67.3%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	35.7	4.74%	48.81%	154,356	3.48%	44.75%
PRIMARY	69,34,12,1	23.4	3.11%	32.07%	98,269	2.22%	28.49%
SECONDARY		14.0	1.86%	19.12%	92,327	2.08%	26.77%
TOTAL		73.1	9.71%	100.00%	344,952	7.78%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08523	0.92147	1.06039	0.94305
SECONDARY		1.11123	0.89990	1.08822	0.91893

PACIFICORP WYOMING 2007 LOSS ANALYSIS

PACIFICORP WYOMING REVISED

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		1,127	MW
GENERATION & PURCHASES-INPUT		9,037,952	MWH
ANNUAL SALES	-OUTPUT	8,548,886	MWH
SYSTEM LOSSES	INPUT	489,066	or 5.41%
	OUTPUT		or 5.72%
SYSTEM LOAD FACTOR		91.5%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	53.4	4.74%	63.68%	314,492	3.48%	64.30%
PRIMARY	69,34,12,1	22.9	2.03%	27.30%	110,747	1.23%	22.64%
SECONDARY		7.6	0.67%	9.02%	63,827	0.71%	13.05%
TOTAL		83.9	7.44%	100.00%	489,066	5.41%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08392	0.92258	1.05594	0.94702
SECONDARY		1.10925	0.90151	1.08136	0.92476

PACIFICORP CALIFORNIA 2007 LOSS ANALYSIS

PACIFICORP CALIFORNIA REVISED

EXHIBIT 1

SUMMARY OF COMPANY DATA

ANNUAL PEAK		160	MW
GENERATION & PURCHASES-INPUT		973,601	MWH
ANNUAL SALES	-OUTPUT	887,818	MWH
SYSTEM LOSSES	INPUT	85,783	or 8.81%
	OUTPUT		or 9.66%
SYSTEM LOAD FACTOR		69.5%	

SUMMARY OF LOSSES - OUTPUT RESULTS

SERVICE	KV	MW		% TOTAL	MWH		% TOTAL
TRANS	345,161,115	7.7	4.81%	45.55%	34,260	3.52%	39.94%
PRIMARY	69,34,12,1	4.9	3.08%	29.16%	20,759	2.13%	24.20%
SECONDARY		4.3	2.67%	25.29%	30,765	3.16%	35.86%
TOTAL		16.9	10.55%	100.00%	85,783	8.81%	100.00%

SUMMARY OF LOSS FACTORS

SERVICE	KV	CUMMULATIVE SALES EXPANSION FACTORS DEMAND		ENERGY	
		d	1/d	e	1/e
TRANS	345,161,115	1.04975	0.95260	1.03605	0.96520
PRIM SUBS	69,46,35	0.00000	0.00000	0.00000	0.00000
PRIMARY	69,34,12,1	1.08478	0.92184	1.05946	0.94388
SECONDARY		1.11961	0.89317	1.09848	0.91035