Idaho Pu. Utilities Commission
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF UNITED WATER IDAHO INC. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR WATER SERVICE IN THE STATE OF IDAHO	**Case No. UWI-W-04-04**

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

DIRECT TESTIMONY OF DENNIS E. PESEAU

1 Q. Please state your name and address.

2 A. My name is Dennis E. Peseau. My address is 1500 Liberty
3 Street, S.E., Suite 250, Salem, OR 97302.

4 Q. By whom and in what capacity are you employed?

5 A. I am President of Utility Resources, Inc. Utility Resources, Inc.
6 consults on a number of economic, financial, engineering and
7 regulatory matters for private and public entities.

8 Q. On whose behalf are you testifying in these proceedings?

9 A. I am testifying on behalf of United Water Idaho Inc. ("United" or
10 "the Company").

11 Q. Does attachment 1 to your testimony describe your professional
12 career and educational background?

13 A. Yes.

14 Q. What is the purpose of your direct testimony in these
15 proceedings?

16 A. I am sponsoring Exhibit 14, a cost of service study ("COSS") of
17 the water system of United, and making rate design
18 recommendations based in part on the COSS. The reason I
19 state that my rate design recommendations are based only "in
20 part" on the COSS is an acknowledgement that here in Idaho,
21 and usually elsewhere, implementation of efficient, fair and
22 equitable rates to United's customers requires a good deal of

1 practical judgment in addition to the cost guidelines given us
2 from the COSS.
3 Q. Have you previously testified before the idaho public utilities
4 commission on cost of service and rate design matters?
5 A. Yes. I have testified before this Commission on such matters on
6 numerous occasions dating back to 1980. I have represented
7 various customer groups previously on COSS and rate design
8 issues involving electricity and natural gas. I believe that this
9 case is the first water system COSS and rate design study that I
10 have prepared in the State of Idaho, although I have testified in
11 water cases on several occasions in Oregon, Nevada and
12 California.
13 Q. What conclusions have you reached from your studies and
14 analyses?
15 A. I conclude that:
16 1. The customer charges now in place are significantly below
17 customers' cost of service and should be raised. I propose that
18 these charges be raised by approximately 36%.
19 2. Customer class distinctions in the present case remain
20 according to meter size.
21 3. There is substantial difference in seasonal commodity costs
22 of service between the winter and summer and the present 25%
23 commodity rate differential should be maintained.

1 Q. How is your testimony organized?

2 A. Prior to my presenting the detailed COSS and rate design
3 proposals, I focus initially on a review of some of the water
4 system cost of service and rate design issues that United,
5 Commission Staff, and intervenors and therefore, this
6 Commission considered in the prior rate case No. UWI-W-98-3
7 and subsequent Order No. 28043. In that case, a number of
8 different COSS and rate design proposals were presented and
9 evaluated. The issues considered there provide a perspective
10 for the COSS and rate design enhancements I discuss below.

11 SIGNIFICANT COSS AND RATE DESIGN ISSUES

12 Q. What significant COSS and rate design issues arose in the 1998
13 rate case that remain pertinent in the present proceedings?

14 A. Leaving aside for the moment the many technical COSS issues
15 pertaining to functionalizing and classifying the numerous cost
16 categories involved in describing the United system, there were
17 threshold issues in the prior rate case.

18 Q. Please briefly explain these threshold issues.

19 A. The first issue pertained to the consensus conclusion that the
20 revenues collected under United's customer charges fell
21 significantly short of covering the costs of serving customers.
22 Customer costs are defined as the costs associated with
23 customer billing, meters, service and fire protection. As

customer costs comprise a significant percentage of customers' bills and they cannot be "avoided" by reducing water consumption, customers tend to prefer low customer charges. The issue in the present case is just how much to raise the present level customer charges, given the continuing disparity that I find between these rates and customer cost of service.

A second important issue was the means by which customer classes were to be defined. For a number of reasons, United's customer classifications, for purposes of COSS have been based on meter size, not classes such as residential, commercial, industrial or public authority. In Case No. UWI-W-98-3 it was recognized by Commission Staff and United that the sampling, load profile and other usage pattern data necessary to construct meaningful residential, commercial and other rate classes would be very costly and difficult to develop. I consider cost distinctions by meter size to be the reasonable classification of costs and continue this practice in the COSS I develop.

A third important rate issue taken up in Case No. UWI-W-98-3 was the design of the usage or commodity rate. This usage-sensitive or commodity portion for rate design is especially important in that it is here that customers confront the price signals that form the basis for efficient water usage as well as conservation decisions.

In the 1998 rate case, the then-existing seasonal rate structure was re-examined in light of certain customers' frustration or confusion over facing different commodity rates during different times of the year. The sense seemed to be "Shouldn't it cost me the same to bathe in the summer or the winter if my consumption is somewhat flat year-round"? I argue below that the answer to this question is "No, but the good news for you is that appropriately seasonalized rates result in your total annual bills for water used to bathe being less for you than in the absence of seasonalized rates." That is, the cost of a bath in the winter is lower by a greater amount than the cost of a bath in the summer is higher, if your annual consumption is relatively flat. As shown more formally below, the reason that annual bills for relatively flat demand water customers are reduced by seasonalizing commodity rates is that, compared to other customers, their consumption occurs relatively more in the winter or "off-season" rate period. With effective communication, these customers' frustration with differentiated bills could not only be softened but perhaps be offset by the knowledge that their level (i.e., efficient) consumption is rewarded by the seasonal rate structure in the form of less expensive annual bills. The reduction in these annual bills is made up from customers that do not have level consumption, such as irrigation loads. The

1 higher percentage of revenues paid by higher summer
2 consumption is as it should be, for the summer period is shown
3 below to have the higher costs of service. So long as there is a
4 reasonable cost basis for seasonal rate differentiation, seasonal
5 rates are fair, equitable and "better" than flat annual rates.
6 Previously, the basis for seasonalizing the Company's rates was
7 informed judgment. The COSS undertaken for United in the
8 present case actually distinguishes and differentiates commodity
9 costs by seasons rigorously rather than relying solely on
10 judgment.
11 Q. Did you consider proposing an inclining or inverted block rate
12 structure here similar to proposals in uwid's last rate case?
13 A. Yes. As part of my preparation for the present case, I read much
14 of the record in Case No. UWI-W-98-3 where the topic of
15 inverted rates was discussed. I note that after the Commission
16 considered the issues pertaining to commodity rates, Order No.
17 28043 concluded that seasonal rather than inverted block rates
18 be implemented, although there was a dissenting opinion on the
19 issue.
20 Q. What is your recommendation with respect to the commodity rate
21 issue?
22 A. There is no perfect means to estimate commodity costs and
23 transfer these costs to rate design. Ultimately judgment not only

about costs but also rate stability, understandability and other equity issues must be addressed.

I do, however, prefer and in this case recommend continued but improved use of seasonal over inverted block rates. While over the years I have estimated and recommended both seasonal and inverted block rates, I believe in this case ratemaking goals are better served with a seasonal rate structure, perhaps modified by a minimal initial summer consumption block.

As Commission Staff and others discussed in Case No. UWI-W-98-3, and in my opinion hold true in this case, seasonal rates:

1. Are able to be estimated formally within the COSS and give more formal foundation and understanding of seasonal cost differences;

2. Although not as simple as annual flat commodity rates, are much simpler and more understandable compared with multiple block rates;

3. Assure a better price signal to and promote conservation by customers than do inverted block rates;

4. Allow customers at all times to know the rates they face, while they may never know the rate they face at any particular point in time with an inverted block rate structure.

Q. Did commission staff in case no. Uwi-w-98-3 correctly point out that the COSS in that case did not tell us directly how costs vary by season?

1 A. Yes. However, in the COSS I offer here, we have seasonalized
2 costs. While this formal seasonal estimation does not eliminate
3 the need for judgment in designing rates, it does nevertheless
4 give a good initial indication of seasonal cost differentiation, and
5 a rate objective to move toward over time.

6 POSSIBLE SUMMER INITIAL LOW-COST RATE BLOCK

7 Q. In your testimony above, you referred to a possible "initial
8 summer consumption block" within a seasonal rate structure.
9 What do you mean by this?

10 A. My critique of inverted block rates pertains to the difficulty and
11 potential confusion associated with multiple blocks that are
12 designed to cover large consumption increments, for example as
13 in the case of base blocks, shoulder blocks and peak usage
14 blocks. In such instances, it is not possible to adequately define
15 these blocks within a cost of service study.

16 However, there are certainly reasons that a noncost-based
17 initial low block rate can be considered for purposes of assisting
18 in keeping the annual costs of small usage customers to a
19 minimum. We have begun attempting to develop the type of bill
20 frequency analysis necessary to estimate a reasonable size for
21 this initial summer block. Due to the need to gather additional
22 data and perform statistical analyses, I have not included an
23 exact initial block proposal here. We anticipate being able to

1 offer a quantification of this proposal for the Commission's
2 consideration during the course of these proceedings.
3 UNITED WATER IDAHO'S COST OF SERVICE STUDY
4 Q. Please describe your cost of service study (COSS).
5 A. United's filing develops a total revenue requirement for metered
6 and fire protection rates of $38.1 million for the twelve months
7 ending May 31, 2005. This revenue requirement is the sum of
8 the Company's expenses, including taxes, and a fair return on its
9 rate base. My COSS begins with the Company's revenue
10 requirement and follows a number of costing conventions,
11 principles and methods generally used in the utility industry and
12 for water companies in particular. This particular study generally
13 corresponds somewhat to the cost study sponsored by United in
14 Case No. UWI-W-98-3 with some new enhancements for
15 functionalizing and seasonalizing costs that this Commission has
16 previously recognized for the electric utilities under its
17 jurisdiction. The COSS follows generally accepted cost of
18 service financial and economic principles, including those found
19 in costing manuals published by the American Water Works
20 Association and NARUC.
21 Schedule 1, consisting of 2 pages, summarizes the final
22 results of the COSS. Provided on this schedule are the final
23 allocations of costs to the general service and fire protection

1 schedules, as well as the summary cost of service rates for
2 seasonal usage, as well as customer costs. The last 2 lines of
3 each page of the schedule, "Existing Revenue" and "Percent
4 Change from Current", show the full cost of service rates and the
5 change in the present rates necessary to achieve cost of service
6 rates. Again, I do not recommend movement to full cost of
7 service. However, I use the cost and present rate information
8 shown on Schedule 1 to reach the rate design recommendations
9 that I make in the following section of my testimony.
10 Q. What does schedule 2 show?
11 A. The 2 page Schedule 2 provides the overall summary results of
12 the COSS. The column "Total Amount" on pages 1 and 2 show
13 the aggregate amounts of operating expenses and rate base
14 related data necessary to adjust the period ending July 31, 2004
15 figures to May 31, 2005. The remaining columns summarize the
16 steps of the service component analysis by breaking these total
17 rate year balances into volume, base demand, excess maximum
18 day, excess maximum hour, customer related O&M, customer
19 meters and services and fire protection.
20 Q. What is the next step in your COSS?
21 A. The next step is shown in Schedule 3. This schedule provides
22 the actual allocation of functionalized costs. A common allocation
23 method, and one recognized by this Commission, is the "Base-

1 Extra Capacity Method." This method separates total costs into
2 the components of base cost, extra capacity cost, customer cost
3 and fire protection costs.
4 Q. What are "base costs" in the base-extra capacity method?
5 A. Base costs represent those costs incurred by the Company for
6 average, flat or baseload levels of water production and
7 consumption by customers. Base costs represent a form of
8 "optimal system" costs as they are the costs of a system utilized
9 at a 100% system load factor that requires no additional peaking
10 facilities or other capacity costs. Base costs are those O&M and
11 capital costs for serving customers at a constant annual rate.
12 Q. What are "extra capacity" costs?
13 A. As the name implies, extra capacity costs are those O&M and
14 capital costs that are over and above the base costs. They are
15 costs for meeting maximum peak demand in excess of average
16 demand and include supply, treatment, pumping and distribution
17 facilities costs.
18 Q. What are customer costs?
19 A. As in most utility functions, water system customer costs are
20 those costs incurred by the Company to provide service to
21 customers independent of the actual level and rate of water
22 consumption. In the present study these costs include the three

functions: customer commercial, customer meters and customer services. The AWWA Manual M1 defines customer costs as:

> Costs directly associated with serving customers, irrespective of the amount of water use. Such costs generally include meter reading, billing, accounting, and collecting expense, and maintenance and capital costs related to meters and associated services. [page 324]

Q. Are you aware that the commission staff has recently proposed that customer costs for electric utilities be defined more narrowly?

A. Yes. However, for United's water system, the above definition should continue to be used for cost of service analysis. All categories of the customer service above are independent of water use. These services are sized initially for customers and do not vary by annual or seasonal demands. Allocating any of these fixed costs to the commodity portion of seasonal rates would distort the usage sensitive water rate.

Q. What are fire protection costs?

A. Fire protection costs include the O&M and capital costs of fire hydrants.

Q. How did you apply the base-extra capacity method to derive the costs associated with these components?

A. The base-extra capacity method formally estimates the base or average demand system costs, the excess maximum day system demand costs and the maximum hour system demand

costs. The method recognizes that extra costs are incurred for meeting maximum day demands over average system demand, and that even greater costs are incurred for facilities required to meet maximum peak hour demands. Accordingly, the base-extra capacity method allocates the total costs of supply, pumping, treatment, T&D, customer, fire protection, general plant and intangibles on the basis of average and peak demand. The actual allocations are made from calculated "factors" or allocators. The results of this step of allocating to the service components for the period ending May 31, 2005 are shown in Schedule 3. Schedule 4 of my exhibit provides the details of the derivation of these factors. Schedule 4 also provides the derivation of all other component, function and seasonal allocators.

Q. What do schedules 5-13 show?

A. Schedules 5-13 provide detailed account information that breaks costs into functions. The functional categories used the COSS are:

1. Intangibles
2. Source of supply
3. Pumping plant
4. Water treatment
5. Transmission and distribution

6. Customer meters and service

7. Fire protection

8. General plant

Q. What does schedule 14 show?

A. Schedule 14 provides rate year pro forma customer and billing information by meter size and revenue count at existing rates and equivalent meter counts. This information is used to derive unit customer costs from aggregate customer costs.

Q. What does schedule 15 show?

A. Schedule 15 reports private fire service information similar to that presented in Schedule 14.

SEASONALIZED COST OF SERVICE

Q. What is the issue you address with respect to cost seasonalization?

A. Although United has had seasonal water rates in effect for some time, the degree of the winter/summer rate differentiation has not before been based on the cost of service study. The issue I now address is the formal estimating of the Company's seasonal cost differences in the context of the COSS. It is not my intent to argue that seasonal rates should be set equal to seasonal cost differences but rather that the actual cost differences be recognized as one important variable in setting final commodity rates in this case.

1 Q. What does your COSS analysis show with regard to United's
2 seasonal cost differences?
3 A. As in all cost of service analyses, there is no single "correct "
4 method to seasonalize costs. Judgment is required. I develop
5 two alternative methods to seasonalize cost of service to provide
6 the Commission insight into the new analyses and give a
7 reasonable range of discretion in setting seasonal rates if it
8 chooses to order seasonal rates.
9 As developed below the two analyses find that the seasonal
10 rate spread based on cost of service falls in the range of 25-
11 70%.
12 Q. Please explain the seasonal cost analysis.
13 A. The seasonal cost study begins with the identification of the
14 appropriate annual functional and component cost categories
15 that are usage sensitive, and therefore, eligible for
16 seasonalization. The COSS identifies volumetric, base demand,
17 excess maximum day and excess maximum hour costs as usage
18 sensitive. The annual dollar amounts for these cost categories
19 are summarized in Schedule 1. The total of these usage
20 sensitive costs in rate year May 31, 2005 is $26,636,100, a very
21 significant percentage of the total revenue requirement of $38.1
22 million.

The various categories identified above each has a unique seasonal characteristic and must be separately estimated. For example, volumetric costs vary directly with seasonal usage. Cost of chemicals is such an example. The more water produced, the more chemical used. Purchased water costs also vary directly with the amount purchased. Base capacity costs, which are incurred to meet annual average demand also vary directly by seasonal usage and therefore should be allocated by respective seasonal winter/summer usages.

The peak or excess maximum demand costs, however, vary disproportionately higher during summer months. Seasonal allocators for the excess maximum day and excess maximum hour demands therefore require considerably more analysis.

Q. How does the COSS develop seasonal cost allocators for the two categories excess maximum day and excess maximum hour?

A. To accomplish this, average monthly usage, maximum day usage and maximum hour usage is computed for each month of the test year. From these data twelve monthly day and hour "excesses" over the respective average monthly demands are calculated.

I computed the two alternative seasonal cost allocators by using two different definitions of summer and winter peak consumption.

Q. Please explain.

A. For the first seasonal allocator, I computed the maximum excess maximum day and hour figures for the single highest peak excess for each season. I then compared the summer single month excess demand with the winter single month excess demand and used the relative differences to seasonalize the costs. The resulting seasonal allocations derived are:

	Seasonal Costs Allocated	
	Summer	Winter
Excess Day	77.4%	22.6%
Excess Hour	70.0%	30.0%

Schedule 4 provides the detailed calculations.

A second alternative seasonal allocator is developed from the same excess demand data. However, for this second allocator, I summed, by season, all months of positive excess demand and used the sum of the total month summer excess demands to the sum of the total monthly winter demands to calculate the allocator. This second allocator results in the following cost allocations:

	Seasonal Costs Allocated	
	Summer	Winter
Excess Day	87.8%	12.2%
Excess Hour	87.9%	12.1%

Q. How are the seasonal excess demand allocators combined with the volumetric and base capacity cost allocators to reach a seasonalization of all these costs?

A. This step is shown for each of the two alternative excess demand allocators in Schedule 1. As shown in the now entitled "Total," the total seasonal costs allocated to the winter and summer seasons are $8,172,948 and $18,463,152 respectively for the single excess peak alternative allocator and $6,555,866 and $20,080,233 for the "sum of all months" excess demand allocator.

On these same tables, the columns designated as winter and summer show the actual amounts of each category, that is volumetric, base capacity, excess maximum day and excess maximum hour capacity allocations to season.

Q. How are the cost of service-based rate differentials determined?

A. The "Unit Cost" row on Schedule 1 reports the winter and summer unit rates required to exactly conform to cost of service. The unit rates under the single peak excess demand allocator are 1.1073 and 1.389 for winter and summer respectively. This is a 25% seasonal rate differential.

1 Q. Do you propose that the commission adopt an "either/or" policy
2 on the choice between the 25% and 70% seasonal cost
3 differences?
4 A. No. As with all cost of service studies, this COSS serves as a
5 check on the reasonableness of existing rates and provides an
6 indication of the possible direction of movement in the future.
7 This Commission has for decades used cost of service studies
8 as a point of reference and a point of departure. There are, of
9 course, numerous other considerations and factors that weigh on
10 the Commission in setting rates and rate design that are fair,
11 reasonable and in the public interest.
12 Q. Do you have recommendations for the commission in regard to
13 the degree of cost-based seasonalization to adopt in these
14 proceedings?
15 A. Yes. First, as a point of reference, the present 25%
16 winter/summer commodity rate differential now in place appears
17 reasonable as it falls in the lower end of the range derived in the
18 COSS. Second, as an indication of direction, the range of
19 seasonal differentiation in the COSS suggests that the present
20 25% differential perhaps should not be reduced in this case and,
21 over time, the Commission may look to broader seasonalization
22 should future studies support this.

I am in these proceedings very comfortable in recommending that the present 25% seasonal rate spread be continued. A corresponding and very important aspect of continuing with the 25% seasonal rate differential is that the public already has faced this differential for many years and, since it also is supported by the COSS, would not require considerable education attached to making major changes to the present differential. This issue is, to a large extent also a rate design issue and is discussed in the context of complete rate design below.

RATE DESIGN

Q. What is your overall rate design proposal?

A. I recommend that the Commission adopt a rate design that:

1. Raises private fire protection rates at the overage percentage increase in revenue requirement of 21.5%.

2. Raises customer charges by an approximate 36% over present levels.

3. Adopts seasonal commodity rates that have a 25% winter/summer differential.

4. Maintains the present distinction among customers on the basis of meter size.

Q. Why do you recommend a uniform rate increase for private fire protection equal to the average system rate increase?

A. As this class is not metered, there is a lack of comparable known and measurable data for private fire protection that is available

1 for the general service class. Rather than make additional
2 assumptions, I recommend the uniform average system rate
3 increase for this class.
4 Q. Why do you recommend that customer charges be raised by
5 36%?
6 A. Again, I begin with references to the COSS. Schedule 1
7 discussed above not only reports the COSS results on seasonal
8 costs, but also shows a comparison of existing customer costs to
9 present customer charges. For example, page 1 and page 2 of
10 Schedule 1 indicates that to move customer charges to full cost
11 of service, revenues from this rate component would have to be
12 raised from $7.3 million to $11 million. And, while I know that
13 considering the raising of customer charges is typically
14 unpopular, the COSS results show that the present customer
15 charges would need to be raised about 51% if brought 100% in
16 line with customer costs. I do not recommend this.
17 In this case I recommend that customer charges be raised to
18 a level that would approximately move one-half the distance from
19 existing to cost of service. Raising the present customer charge
20 by the average of the overall requested rate increase, 21.5%,
21 and the COSS level of 51%, for an approximate 36% increase
22 would achieve this objective.

1 Q. What is the outcome of not moving customer charges a
2 significant distance toward cost of service?
3 A. Any and all costs not recovered in customer charges must be
4 collected in commodity rates that are already well above rates
5 that equal cost of service. In this case, both summer and winter
6 commodity rates are considerably higher than justified on a cost
7 of service basis. I believe that an increase of 36% in customer
8 charges fairly balances the goals of gradualism and cost-based
9 rates.
10 Q. Does raising the customer charges "mute" the seasonal
11 commodity rate price signals?
12 A. No. Commodity rate price signals should reflect cost causation.
13 At proposed rates, customer charges will continue to be
14 approximately $1.1 million below cost of service. Therefore, far
15 from having "muted" commodity price signals, proposed
16 commodity rates recover about $1.1 million above cost of
17 service. Again, I do not propose a move to full cost of service
18 now, or probably anytime in the near future, but that some
19 substantial increase be made in this case.
20 Q. Do you have other reasons for recommending that the
21 winter/summer commodity rate differential be kept at 25%, which
22 is at the lower end of your range?

1 A. Yes. As I discussed above the 25% seasonal differential has
2 been in place for some time. But in addition, this Commission
3 has favored gradual implementation of seasonal rates. For
4 example, in the face of a broad range of seasonal cost
5 differences in the recent Idaho Power Company general rate
6 case, this Commission adopted a low end of a seasonal cost
7 differential range of 12.5%. The present United seasonal
8 commodity rate differential is twice that adopted for Idaho Power.
9 Q. How might the issue of customers that have flat monthly loads
10 be addressed with regard to the issue of summer bills being
11 higher than for the same uses in the winter?
12 A. This is the "baths costing more in the summer" issue I referred to
13 in the introduction to my testimony. While seasonal rates
14 obviously cause different levels of billing for the same
15 consumption occurring in different months, customers need to be
16 made aware that there are nevertheless benefits of seasonal
17 rates. For a customer whose consumption is relatively "flat" or
18 level over the year, demonstrations can be made that seasonal
19 rates result in his paying lower annual amounts than in the
20 absence of seasonal rates.
21 Q. Please explain.
22 A. The following table demonstrates that level consumption under
23 the seasonal rates proposed in this case reduce annual

customers bills. The table compares the annual bills of a customer using the Company average monthly consumption of 10 CCF per month. Here it is assumed that this customer uses this 10 CCF in every month of the year:

Month	Use (CCF))	Flat Rate $/CCF	Seasonal Rate $/CCF	Flat Bill	Seasonal Bill
January	10	1.29	1.11	$12.90	$11.10
February	10	1.29	1.11	$12.90	$11.10
March	10	1.29	1.11	$12.90	$11.10
April	10	1.29	1.11	$12.90	$11.10
May	10	1.29	1.39	$12.90	$13.90
June	10	1.29	1.39	$12.90	$13.90
July	10	1.29	1.39	$12.90	$13.90
August	10	1.29	1.39	$12.90	$13.90
September	10	1.29	1.39	$12.90	$13.90
October	10	1.29	1.11	$12.90	$11.10
November	10	1.29	1.11	$12.90	$11.10
December	10	1.29	1.11	$12.90	$11.10
Total				$154.80	$147.20

The COSS estimates that the average annual commodity rate in this case is $1.29 per CCF. And, as shown in Schedule 1, page 1, the proposed seasonal commodity rates in this case are $1.11 and $1.39 per CCF for the winter and summer seasons, respectively. The table prices out the level consumption of 10 CCF under the average annual versus the seasonal rates for this customer. In this instance, the customer saves $7.60 per year, or over 5% with the seasonal rates. Thus while this customer may pay more for a bath in the summer than in the winter, he pays less for the two over the course of the year.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE APPLICATION OF UNITED WATER IDAHO INC. FOR AUTHORITY TO INCREASE ITS RATES AND CHARGES FOR WATER SERVICE IN THE STATE OF IDAHO	**Case No. UWI-W-04-04**

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

ATTACHMENT 1 TO THE

DIRECT TESTIMONY OF DENNIS E. PESEAU

STATEMENT OF OCCUPATIONAL AND
EDUCATIONAL HISTORY AND QUALIFICATIONS
DENNIS E. PESEAU

Dr. Peseau has conducted economic and financial studies for regulated industries for the past thirty years. In 1972, he was employed by Southern California Edison Company as Associate Economic Analyst, and later as Economic Analyst. His responsibilities included review of financial testimony, incremental cost studies, rate design, econometric estimation of demand elasticities and various areas in the field of energy and economic growth. Also, he was asked by Edison Electrical Institute to study and evaluate several prominent energy models as part of the Ad Hoc Committee on Economic Growth and Energy Pricing.

From 1974 to 1978, Dr. Peseau was employed by the Public Utility Commissioner of Oregon as Senior Economist. There he conducted a number of economic and financial studies and prepared testimony pertaining to public utilities.

In 1978 Dr. Peseau established the Northwest office of Zinder Companies, Inc. He has since submitted testimony on economic and financial matters before state regulatory commissions in Alaska, California, Idaho, Maryland, Minnesota, Montana, Nevada, Washington, Wyoming, the District of Columbia, the Bonneville Power Administration and the Public Utilities Board of Alberta on over one hundred occasions. He has conducted marginal cost and rate design studies and prepared testimony on these matters in Alaska, California, Idaho, Maryland, Minnesota, Nevada, Oregon, Washington and in the District of Columbia. He has also conducted cost and rate studies regarding PURPA issues in the states of Alaska, California, Idaho, Montana, Nevada, New York, Washington, and Washington, D.C.

Dr. Peseau holds the B.A., M.A. and Ph.D. degrees in economics.

He has co-authored a book in the field of industrial organization entitled, Size, Profits and Executive Compensation in the Large Corporation, which devotes a chapter to regulated industries.

Dr. Peseau has published articles in the following professional journals: Review of Economics and Statistics, Atlantic Economic Journal, Journal of Financial Management, and Journal of Regional Science. His articles have been read before the Econometric Society, the Western Economic Association, the Financial Management Association, the Regional Science Association and universities in the United Kingdom as well as in the United States.

He has guest lectured on marginal costing methods in seminars in New Jersey and California for the Center of Professional Advancement. He has also guest lectured on cost of capital for the public utility industry before the Pacific Coast Gas and Electric Association, and for the Executive Seminar at the Colgate Darden Graduate School of Business, University of Virginia.

Dr. Peseau and his firm have participated with and been members of the American Economic Association, the American Financial Association, the Western Economic Association, the Atlantic Economic Association and the Financial Management Association. He was formerly a member of the Staff Subcommittee on Economics of the National Association of Regulatory Utility Commissioners.

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