- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PacifiCorp for Approval of its Proposed Electric Rate Schedules and Electric Service Regulations	**|**	**Docket No. 01-035-01 Utah Division of Public Utilities Exhibit No. DPU R12**

Rebuttal Testimony of

George R. Compton, Ph.D.

For the Division of Public Utilities

Department of Commerce

State of Utah

August 31, 2001

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I. INTRODUCTION

Q. What is your name, and by whom are you employed?

A. George R. Compton. I am a Technical Consultant for the Division of Public Utilities (UDPU, DPU, or Division) of the Utah Department of Commerce.

Q. Are you the same George Compton who filed rate design testimony on June 16th?

A.. I am.

Q. What is the purpose of this, your rebuttal testimony?

A. I will be responding to suggestions/criticisms made by Dr. Charles Johnson (representing the Salt Lake Community Action Program, Crossroads Urban Center, and Utah Legislative Watch) and by Joseph Herz, P.E. (representing the United States Executive Agencies) in the direct testimonies they pre-filed on June 15th regarding PacifiCorp's cost of service and spread of rates. More specifically, I will respond to Dr. Johnson's suggestion that a discounted rate be applied to low-use customers since they are less likely to be heavy peak period consumers. I will also respond to Mr. Herz's suggestion that more costs be assigned to residential customers via an abandonment of this Commission's practice of allocating 25% of the fixed generation costs on the basis of relative energy consumption (and instead allocating 100% of such costs on the basis of peak demands).

II. REDUCING RATES FOR LOW-USE RESIDENTIAL CUSTOMERS?

Q. On page 13 of his June 15th direct testimony, Dr. Johnson "recommend[s] that the Commission make a finding in its Order that the cost of serving low-income customers is lower than the cost of serving other residential customers." What do you see as the basis of that recommendation?

A. In my estimation, the most compelling reason is his observation that while low-income customers' average monthly consumption is 11% below that of other residential customers, the former's summer-period consumption is 21% below the overall average. As a consequence, low-income customers' usage during the high-cost peak period is disproportionately lower than the average customer's.

Q. How would you explain that phenomenon?

A. Low-income customers are less likely to have household space-cooling systems, particularly refrigerated air-conditioning.

Q. What kind of rate design would capture the lower cost that is incident to a lower level of usage?

A. An inverted block rate, such as the Division and the Company are recommending, would accomplish that objective.

Q. Dr. Johnson expressed dissatisfaction that with the Company's inverted-block rate, "the difference in the price between the two blocks is not great enough...." (p. 18) Obviously the same criticism would apply to the rate design you recommended on behalf of the Division. What cost consideration would mitigate your justification for a substantial discount for low volumes of usage?

A. In Utah, the customer charge is well below the direct, customer-based cost of service. Accordingly, a substantial portion of the customer costs are covered in the energy charge. The associated tendency for low users of energy to not pay their full customer costs is exacerbated by an inverted-block energy charge. It is the Division's judgement that our level of "inversion" strikes a reasonable balance between recognizing the additional costs of heavy summer usage and not wanting to overly subsidize small users.

III. INCREASING THE GENERATION PLANT ALLOCATION TO THE RESIDENTIAL CLASS?

Q. Generally speaking, what have been the mechanisms by which fixed and variable generation costs have been allocated to the customer classes?

A. Variable costs, which are largely fuel costs, have been allocated to the customer classes on the basis of their energy, or kWh, consumption. Fixed costs, which are the capital costs (including depreciation, taxes, and return on investment) and the non-variable operation and maintenance (O&M) costs relating to the generation plants, are allocated on a 75/25 demand/energy basis. In other words, 25% of the fixed costs are allocated to the customer classes on the basis of their relative energy consumption, and the remaining 75% is allocated on the basis of the customer classes' relative contributions to the monthly peaks.

Q. What is Mr. Herz's argument against that approach?

A. He states the following (on pages 7 and 8):

> PacifiCorp's use of a 75/25 demand/energy allocation factor is inconsistent with its definition of demand (fixed) costs and is inappropriate in that it does not allocate demand related costs on the basis of a demand factor, but rather on the basis of a factor consisting of weighted demand and energy factors. The result is an inequitable distribution of demand or fixed costs between the customer classes.
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> ....
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> PacifiCorp's use of a 75/25 demand/energy allocation factor is inappropriate in that a portion of its demand related costs are allocated according to energy use. Demand related costs are incurred to meet Utah's share of PacifiCorp's demand requirements, not necessarily the energy usage.
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> ....
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> PacifiCorp's use of a 75/25 demand/energy allocation factor to allocate its demand costs overstates the revenue requirement responsibility for its high load factor customers.

Q. Do you agree with Mr. Herz's basic point?

A. I do not. What Mr. Herz doesn't seem to recognize is that you can't equate demand costs with fixed costs. That is because a substantial portion of fixed costs involved with electricity generation are attributable to a desire to economize on energy, or fuel, costs. Specifically, if a utility were only required to meet its peak hours' needs, it could rely upon relatively inexpensive peaking plants. But with only peaking plants, the utility's fuel costs would be exorbitant. To save on fuel costs -- indeed to minimize total generation costs -- utilities invest in the much-more-expensive baseload plants. As a consequence, a substantial portion of the fixed costs associated with generation plants are truly energy-related, not demand-related. Accordingly, it is entirely appropriate to allocate some of the fixed generation costs in proportion to energy consumption.

Q. Does that line of reasoning comport with earlier Division positions and Utah PSC findings?

A. It does. Section IV.A.2. of the Commission's Order in Docket 97-035-01 contains the following language:

> Since energy plays a role in the selection of least-cost resources, the Division [via Ken Powell's rebuttal testimony] concludes that some weight needs to be given to energy in planning for new capacity, and that the current weight of 25 percent is reasonable. We find the qualitative argument offered by the Division to be the more convincing. We conclude that twelve monthly coincident peaks, with a 75 percent demand-related and 25 percent energy-related mix, is the appropriate basis for allocating production and transmission costs to classes in the Utah jurisdiction.

I would also note that the inter-jurisdictional allocations have also employed the 75/25 relationship for generation and transmission costs.

Q. In your previous answer you said that "some" of the fixed generation costs should be allocated in proportion to energy consumption. Would your "some" be 25% as per the current practice?

A. You ask a very difficult question. To get some kind of quantitative "feel" for this matter I put together a simplified numerical example to illustrate the concepts involved. That analysis suggests that the 25% figure is reasonable. To perform a definitive analysis employing all (or even a large portion of) the elements of the PacifiCorp customer demand/profile and resources would be horrendously complex.

Q. Could you please outline the numerical analysis that led to the conclusion that something in the neighborhood of 25% of the fixed generation system costs should be allocated in proportion to relative energy consumption?

A. Certainly. The basic approach was to develop stand-alone costs for serving nothing but the industrial class and nothing but the residential class. Those costs were then compared to the outcomes of allocating costs of a system which served those two classes jointly. The obvious presumption is that a system which serves two customer classes should charge neither class more than what it would cost to serve it by itself.

In the numerical example, the residential and industrial classes were constructed to have load factors of approximately 19% and 75%, respectively. Peaking generation was assumed to have cost characteristics similar to the Gadsby plant; base-load generation used cost figures similar to those of Hermiston. Stand-alone average costs were, respectively, 6.5¢/kWh and 3.77¢/kWh for the residential and industrial classes.[1]

Q. What was the outcome of your analysis?

A. Combining the loads and resources and using the 75/25 fixed cost allocator does in fact penalize the industrial customers -- but by a very small amount (i.e., about one-half of one percent). By contrast, applying Mr. Herz's recommendation would add over 9% to residential costs above and beyond what they would be with a stand-alone generation system that combined peaking with base-load equipment.

Q. Those are interesting results. But I suspect the outcome is dependent upon your inputs. Have you run some other examples wherein, for example, the residential and industrial load factors are altered?

A. I have. I increased the residential load factor by about half (i.e., from 19.33% to 31.34%) and then by half again (i.e., to 45.32%), and reduced the industrial load factor slightly (i.e., from 75% to 70%) to see what would happen. I also altered the shape of the residential load duration curve slightly. The results were comparable to my base case. The simple demand allocator of fixed costs (i.e., Mr. Herz's) drastically over-allocated to the residential class; the 75/25 approach gave much closer results -- and in some instances (i.e., with the 31% residential load factor) the 75/25 approach *over*-allocated to the residential class.

Q. Incidentally, on what basis did you select your load factors for your examples?

A. Discussions with Division and Company personnel yielded estimates of the residential load factor from 15% to slightly over 30%, and estimate of the industrial load factor in the 70% to 80% range.

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[1] These figures are below current tariff amounts because common overheads, transmission, distribution, and customer costs are not included. Since industrial distribution and customer costs are comparatively low, the indicated industrial cost comes much closer to its current tariff than does the residential cost.

Q. Have you prepared an exposition which contains the details of your primary numerical analysis for anyone who might want to double-check your figures?

A. I have. It is the Attachment to this testimony.

Q. Would you summarize this portion of your testimony?

A. I have presented a stylized analysis which incorporates fairly realistic load duration curves for industrial and residential customer classes and fairly realistic cost characteristics of baseload and peaking generation. The purpose of the analysis was to corroborate an intuitive presumption supporting the current general allocation approach -- to the effect that since a portion of fixed costs are incurred to economize on variable (i.e., fuel) costs, it is entirely appropriate to allocate some of the fixed costs on the basis of energy consumption. I have made no claim regarding the specific proportion of fixed costs that should be allocated according to energy consumption. The burden of "proof" to come up with some kind of definitive study incorporating the specifics of PacifiCorp's loads and resources would lie with whomever sought to depart from the established 25%/75% ratio.

Q. Does that conclude your prefiled rebuttal testimony?

A. It does, thank you.

ATTACHMENT: A Numerical Example Illustrating the Need to Allocate Some of the Generation Fixed Costs According to Relative Energy Consumption

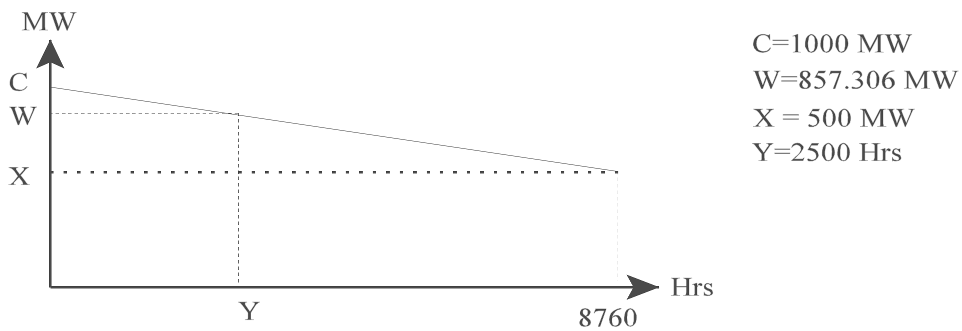
I. Resources' Cost Characteristics.
- A. Peaking Plant:
  - 1. Fixed Costs: \$50/kW-yr.
  - 2. Variable Costs: 4.5¢/kWh
- B. Baseload Plant
  - 1. Fixed Costs: \$107.5/kW-yr.
  - 2. Variable Costs: 2.2¢/kWh

II. Cut-over Hours of Operation (i.e., where the total cost of electricity produced by a kW of baseload plant operating for Y hours equals the cost of electricity produced from a kW of peaking plant operating for Y hours):

$$\$107.5 + (Y \text{ hrs}) \times \$0.022/\text{hr} = \$50 + (Y \text{ hrs}) \times \$0.045/\text{hr}$$

$$Y = 2500 \text{ hours}$$

III. Industrial Load Characteristics:
- A. Peak load (C): 1000MWs
- B. Minimum Load (X): 500MWs
- C. Simplifying assumption: The load duration is a straight line from the level C to X, as shown below.
- D. Total energy: 6,570,000 MWh's (see IV.C., below)
- E. Load factor = 6,570,000/(1000x8760) = 75%, where1000 is the total capacity; 8760 is the total number of hours in a year.



IV. Stand-alone Cost of Serving the Industrial Load:

A. Baseload and peaking plant mix:

1. Baseload capacity (W)

W = the load corresponding to Y hours of plant operation (see II), where

Y/8760 = (C-W)/(C-X) [i.e., geometric relationships].

Substituting in the known values and solving for W yields...

W = 857.306 MWs

2. Peaking capacity = Peak load - Baseload capacity

= 1000 - 857.306 = 142.694 MWs

B. Fixed costs: $99,295,091

1. Baseload fixed costs: 857,306kW x $107.5/kW = $92,160,388

2. Peaking plant fixed costs: 142,694kW x $50/kW = $7,134,703

C. Energy sources/mix:

1. Baseload energy (in MWh's):

(X x 8760) + (W - X)xY + (W - X)x(8760 - Y)/2 = 6,391,632.4 MWh's

2. Peaking plant energy (in MWh's):

(C - W)xY/2 = 178,367.6 Mwh's

3. Total energy = 6,391,632.4 + 178,367.6 = 6,570,000MWh's

D. Variable costs: $148,642,454

1. Baseload plant: 6,391,632.4MWh x $22/MWh = $140,615,913

2. Peaking plant: 178,367.6MWh x $45/MWh = $8,026,541

E. Total costs = Fixed costs + Variable costs = $247,937,545

F. Average costs = (Total costs)/(Total energy) = $37.74/MWh = 3.77¢/kWh

V. Residential Load Characteristics:

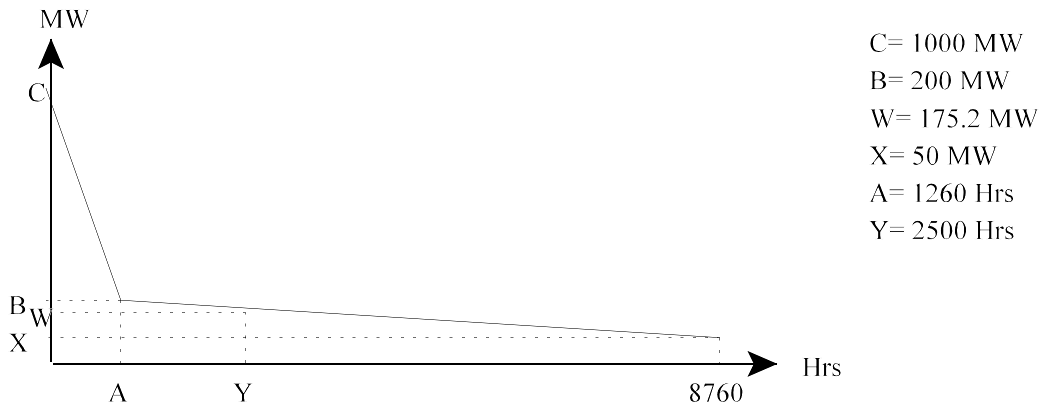
A. Peak load (C): 1000MWs

B. Minimum Load (X): 50MWs

C. Assumption: The load duration curve contains an exaggerated peak and incorporates a pair of straight lines whose point of inflection has the coordinates (A,B)=(1260hrs,200MWs).

D. Total energy: 1,693,500 MWh's (see VI.C., below)

E. Load factor = 1,693,500/(1000x8760) = 19.33%



VI. Stand-alone Cost of Serving the Residential Load:

A. Baseload and peaking plant mix:

1. Baseload capacity (W)

W = the load corresponding to Y hours of plant operation, where

(B-X)/(8760-A) = (B-W)/(Y-A) [i.e., geometric relationships].

Substituting in the known values and solving for W yields...

W = 175.2 MWs

2. Peaking capacity = Peak load - Baseload capacity

= 1000 - 175.2 = 824.8 MWs

B. Fixed costs: $60,074,000

1. Baseload fixed costs: 175,200kW x $107.5/kW = $18,834,000

2. Peaking plant fixed costs: 824,800kW x $50/kW = $41,240,000

C. Energy sources/mix:

1. Baseload energy (in MWh's):

(X x 8760) + (W - X)xY + (W - X)x(8760 - Y)/2 = 1,142,876 MWh's

2. Peaking plant energy (in MWh's):

(C - B)xA/2 + (B - W)xA + (B - W)x(Y - A)/2 = 550,624 Mwh's

3. Total energy = 1,142,876 + 550,624 = 1,693,500MWh's

D. Variable costs: $49,921,352

1. Baseload plant: 1,142,876MWh x $22/MWh = $25,143,272

2. Peaking plant: 550,624MWh x $45/MWh = $24,778,080

E. Total costs = Fixed costs + Variable costs = $109,995,352

F. Average costs = (Total costs)/(Total energy) = $64.95/MWh = 6.5¢/kWh

VII. Allocated System Costs of Serving Industrial and Residential Loads

A. Simplifying assumption: There are no diversity benefits from serving industrial and residential customers in the same locale. Accordingly, total system costs equal the sum of the stand-alone costs of serving the industrial and residential loads.

B. Implications of the simplifying assumption:

1. System load characteristics:

a. System peak demand: 1000 MW’s + 1000 MW’s = 2000 MW’s

b. System total energy consumption:
6,570,000MWh’s + 1,693,500MWh’s = 8,263,500MWh’s

2. System cost characteristics:

a. System fixed costs: $99,295,091 + $60,074,000 = $159,369,091

b. System variable costs: $148,642,454 + $49,921,352
= $198,563,806

c. System total costs = $357,932,897

C. “Herz-style” cost allocations:

1. Variable cost allocators:
(Class energy consumption)/(System energy consumption)

a. Industrial variable cost allocator:
6,570,000MWh’s/8,263,500MWh’s = 79.51%

b. Residential variable cost allocator:
1,693,500MWh’s/8,263,500MWh’s = 20.49%

2. Variable cost allocation:
(Class variable cost allocator)x(System variable costs)

a. Industrial variable cost allocation:
79.51% x $198,563,806 = $157,870,661

b. Residential variable cost allocation:
20.49% x $198,563,806 = $40,693,145

3. Fixed cost allocators:
(Class [coincident] peak demand)/(System peak demand)

a. Industrial fixed cost allocator:
1000 MW’s/2000 MW’s = 50%

b. Residential fixed cost allocator:
1000 MW’s/2000 MW’s = 50%

4. Fixed cost allocation:
(Class fixed cost allocator)x(System fixed costs)

a. Industrial fixed cost allocation:
50% x $159,369,091 = $79,684,545

b. Residential fixed cost allocation:
50% x $159,369,091 = $79,684,545

5. Classes' Costs of Service:
(Class's allocation of variable costs + Class's allocation of fixed costs)

a. Industrial class's "cost of service":
$157,870,661 + $79,684,545 = $237,555,206

b. Residential class's "cost of service":
$40,693,145 + $79,684,545 = $120,377,690

6. Increase (decrease) in allocated versus stand-alone costs:

a. Industrial class: ($10,382,339)

b. Residential class: $10,382,338

D. "75/25-style" cost allocations:

1. Variable & energy cost allocators: *Same as E.1.*

a. Industrial variable cost allocator: 79.51%

b. Residential variable cost allocator: 20.49%

2. Variable & energy cost allocation: *Same as E.2.*

a. Industrial variable & energy cost allocation: $157,870,661

b. Residential variable & energy cost allocation: $40,693,145

3. Demand cost allocators: *Same as E.3.*
(Class [coincident] peak demand)/(System peak demand)

a. Industrial demand cost allocator:
1000 MW's/2000 MW's = 50%

b. Residential demand cost allocator:
1000 MW's/2000 MW's = 50%

4. Fixed cost allocation:
{(Class demand cost allocator) x (75% x System fixed costs)}
+ {(Class energy cost allocator) x (25% x System fixed costs)}

a. Industrial fixed cost allocation:
{50% x (.75 x $159,369,091)} + {79.51% x (.25 x $159,369,091)}
= $91,442,000

b. Residential fixed cost allocation:
{50% x (.75 x $159,369,091)} + {20.49% x (.25 x $159,369,091)}
= $67,927,091

5. Classes' Costs of Service:
(Class's allocation of variable costs + Class's allocation of fixed costs)

a. Industrial class's "cost of service":
$157,870,661 + $91,442,000 = $249,312,661

b. Residential class's "cost of service":

$40,693,145 + $67,927,091 = $108,620,236

6. Increase (decrease) in allocated versus stand-alone costs:

a. Industrial class: $1,375,116

b. Residential class: ($1,375,116)

E. Conclusion from example: The Herz-style approach over-allocate costs to the residential class by over 9%. The 75/25 approach over-allocate costs to the industrial class by less than 1%. The 75/25 approach comes closer to the true (i.e., stand-alone) costs.