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UTAH PUBLIC SERVICE COMMISSION

DAVID L. WILKINSON #3472
Attorney General
STEPHEN G. SCHWENDIMAN #2891
Chief, Assistant Attorney General
MICHAEL L. GINSBERG #4516
Assistant Attorney General
Tax & Business Regulation Division
130 State Capitol
Salt Lake City, Utah 84114
Telephone: (801) 538-1301

- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

IN THE MATTER OF THE APPLICATION OF UTAH POWER & LIGHT COMPANY, AND PC/UP&L MERGING CORP. (TO BE RENAMED PACIFICORP) FOR AN ORDER AUTHORIZING THE MERGER OF THE UTAH POWER & LIGHT COMPANY AND PACIFICORP INTO PC/UP&L MERGING CORP. AND AUTHORIZING THE ISSUANCE OF SECURITIES, ADOPTION OF TARIFFS, AND TRANSFER OF CERTIFICATES OF PUBLIC CONVENIENCE AND NECESSSITY AND AUTHORITIES IN CONNECTION THEREWITH.	<u>Case No. 87-035-27</u> <u>BRIEF OF THE DIVISION OF PUBLIC UTILITIES</u>

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INTRODUCTION

On November 20, 1987, this Commission reaffirmed the standard of approval to be used in a merger proceeding. The Commission stated:

> We are of the view that the necessary predicate for a determination that the proposed merger is "in the public interest" is a sum net positive benefit to the public in this state . . . . In all likelihood, there will be some positive benefits and some negative impact. Our task is to consider them all, giving each its proper weight, and determine whether on balance the merger is beneficial or detrimental to the public.[1]

In conducting its analysis, the Division evaluated both benefits and detriments associated with the merger. In making its recommendation, the Division conducted five major forms of analysis:

1. Determine whether or not the expected merger benefits presented by the Applicant can reasonably be expected to occur;[2]

2. Develop sensitivity analyses to determine how those benefits will be altered by modifications of basic underlying assumptions;

3. Present an analysis of the impact of the merger on employment, coal usage, State taxes, increased affiliated relationships, local control, and any increased regulatory burdens and risks associated with the merger. Many of the areas listed herein are potential negative aspects of the merger which were analyzed and measured against the positive benefits

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1 Docket #87-035-27, Order, November 20, 1987, p.2.

2 As to non-power costs savings, see DPU Exh. 1 (Burrup). As to power costs savings and capacity savings, see DPU Exh. 5 (Weaver). As to economic development, see DPU Exh. 2 (Barber).

4. Present a financial analysis--including sensitivity analyses--of each utility's five year financial plan to determine the impact of the merger on the financial viability of the merged company and the impact of the merger on the shareholders of each company.[3]

5. Provide a summary of the analysis performed by other witnesses and develop a worst case analysis of merger benefits and costs to determine if the promised rate reductions could be cost justified under a worst case set of assumptions. This includes evaluation of the likelihood of the worst case set of assumptions occurring.[4]

After performing the analysis, the following broad conclusions were reached:

1. Even under the worst case assumptions, positive, significant benefits in the form of lower costs flow from the merger. These worst case benefits support both the 2% and 5% reductions promised by the Applicant.

2. Only if one assumes that non-Utah jurisdictions have non-cost based rate reductions as a result of merger benefits, will the worst case scenario not support a 5% rate

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3 DPU Exh. 6 (Eatmon).

4 DPU Exh. 7 (Powell).

duction.[5]

3. The merger will have minimal impact coal production.

4. Although there is an impact on Utah taxes and employment, this impact is minimal and could possibly be eliminated if the Applicants economic development works.

5. Although PacifiCorp has more affiliated relationship than UP&L, PacifiCorp has agreed to a variety of reporting and other conditions to the merger which diminish any concern.

6. The Division concluded that there will be additional regulatory work, particularly in the early years of the merger. This additional regulatory work, however, does not create any additional complexities that cannot adequately be addressed by Utah regulators. In particular, these concerns have been reduced by the commitments made by the Applicant to 1) establish multi-state task forces on allocation within six weeks of the effective date of the merger, and 2) to file basically a revenue requirement and cost of service filing within the first quarter of 1989 and each year thereafter.

After evaluating these conclusions, the Division recommends that the merger be approved subject to the conditions and commitments made by the company or recommended by the Division.

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[5] California, Idaho, Wyoming and Montana have issued orders approving the merger with no rate reductions required. Washington has issued an order requiring a rate reduction of approximately $4 million. This $4 million rate reduction was considered by Mr. Eatmon in his analysis of synergies. He concluded that a reduction in cash flow to cover the $4 million rate reduction would have minimal impact upon the acquisitions net benefits to Pacificorp. DPU Exh. 6.0, p. 69) In addition, there are three other reasons why this potential scenario did not cause the Division to change its conclusion that the merger is in the public interest. These three factors are: 1) that the Applicants have committed to a 5% rate reduction whether or not it is cost based. 2) That the worst case scenario is a combination of a number of adverse items happening over an extended period of time and has little probability of occuring. 3) Benefits beyond 1992 increase significantly and any shortfall in benefits during the early years of the merger will be eliminated as a result of savings occuring after the five year study period.

I

Non Power Supply Savings
Resulting From the Merger

This section deals with merger benefits from the following categories: a) reduced construction, b) economic development, c) administrative combinations, and d) manpower efficiencies. The following table summarizes the positions of the parties.

COMPARISON OF NON POWER SUPPLY MERGER BENEFITS
Five Year Totals
(in millions)

	REDUCED CONST	ECON DEVELOP	ADMIN COMB	MANPOWER EFFIC	TOTAL
Applicants[6]	$28	$37	$99	$155	$319
Division[7]					
a) Best case	$28	$37	$99	$155	$319
b) Worst case	$7	$0	$64	$77	$148
Committee[8]					
a) Low case	($32)	$0	$50	$78	$96
b) High case	($18)	$0	$50	$78	$111
BMT[9]	($8)	$0	$18	$0	$9

1. <u>Reduced Construction.</u>

Reduced Construction amounts to about 7% of the claimed 1992 benefits.[10] The Division developed a lower and upper limit

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6 Witness Reed Exh. 5.2

7 Witness Powell Exh. DPU 7.2

8 Witness Bernow Testimony Table 18 and SERA Late Filed Exhibit

9 Witness Winterfeld Exh. CKW 9

10 DPU Exh. 7.0 (Powell) p. 5

expected reduced construction benefits. The lower limit recognized that little or no reduced construction benefits would occur to distribution and general plant. The major difference between the Division's and Applicant's estimates of reduced construction and that of the Committee appear to revolve around the need for additional transmission facilities in the early stages of the merger. In its initial filing, the Committee asserted that a $7 million phase shifter and the Treasureton-Bridger transmission systems had been left out of the Applicant's cost estimate.[11] Both of these elements were included by the Applicant and were carried forward into the Division's analysis. It is unclear if when correcting model inputs, the Committee made a correction as to reduced construction costs was made. The need for additional transmission capability in order to transfer merger benefits from one division to another will be discussed later.

2. Economic Development.

In evaluating the importance of the claimed economic development benefits to the merger, two factors should be kept in mind. First, economic development benefits result from a net increase in revenues to the Utah jurisdiction. These revenues will automatically be included in the calculation of jurisdictional revenue requirements in each state where the economic development occur. Therefore, allocating revenues from economic development is not an issue. Second, it will be

11 DPU R 5.3 (Weaver) P. 3

tually impossible to determine whether or not an industry located in the Utah division as a result of the economic development program. Third, it is only relevant to measure economic development benefits if total merger benefits do not materialize. At that point, both PacifiCorps' commitment never to raise rates as a result of the merger as well as measuring economic development benefits becomes relevant.[12]

3. Administrative Combinations.

Although the Division developed a worst case analysis, the conclusion reached by Mr. Burrup was that the anticipated savings from administrative combinations is conservative and that the vast majority of those savings can occur only with the merger.[13]

4. Manpower Efficiencies.

Over the next five years, in its estimate of manpower efficiencies, the Applicant estimated approximately twice as many reductions in work force in the PP&L division than in the Utah division. This recognizes the fact that there have been

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[12] The Division presented economic development testimony through Mr. Barber, DPU Exh. 2.0. The Committee and BMI also presented testimony that it was unlikely that the economic development benefits of the merger would occur.

[13] DPU Exh. 1.0 (Burrup) p. 14-16. Mr. Burrup indicated that there are additional areas of significantly greater savings for insurance programs not originally forecast by the company in its original filings that will be over an above the insurance savings outlined in the above table. In addition, Mr. Burrup indicated other potential areas of regulatory adjustments. This could include the elimination of IPP amortization or insurance which was included in the utility's forecast, the potential elimination of directors' insurance for UP&L directors after the merger has occured.

significant reductions in work force in the Utah division in the last few years.

5. Conclusions.

Even in the Division's worst case analysis, savings from non-power cost areas will amount to approximately $148 million. This is a significant reduction in current operating costs of the two utilities. Under the Division's best case analysis, it was believed not unreasonable to expect benefits from the merger in the $300 million range.

II

CAPACITY SAVINGS RESULTING FROM THE MERGER

Three issues have arisen regarding the proper estimation of reductions in revenue requirements associated with the acquisition and operation of new generation resources: (1) attribution of such saving to the merger, (2) the appropriate analytical approach, and (3) the appropriate assumptions.

A. Attribution

The question here is the extent to which UP&L as a stand alone company could establish contractual relationships with other utilities through which it could achieve the same capacity savings as estimated by the Applicants and attributed by them to the merger. BMT witness Goff argues that nearly all such benefits could in fact be achieved though contact and therefore do not represent legitimate merger benefits.[14] The Division witness argues that the likelihood of such contracting is limited

[14] Goff Direct pp. 11 and scattered thereafter

d therefore capacity savings should be attributed as benefits to the merger.[15] The Applicants have pointed out the difficulties inherent in such a contracting process. It is entirely unreasonable to treat the possibility of overcoming such difficulties and achieving a contractual realization of such cost reductions as a certainty and therefore to reject such cost reductions as not attributable to the merger.

An additional point made by the Division is that those advancing the contractibility argument have claimed only that deals as good as the merger might be contracted. No claim has been made that a better deal might be achieved. Thus, it is unreasonable to reject the merger "one bird in the hand" in hopes of _perhaps_ achieving a contracted "one bird in the bush".[16]

B. Modelling-Analytical Approaches

The Division and the Applicants have adopted variants of the same general approach.[17] This consists of projecting and costing a capacity expansion plan for each of the companies stand alone, and one for the merged company. The difference between the sum of the stand alones and the merged case constitutes the capacity savings. Both analyses result in major long range capacity savings from the merger.[18] The Division further

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15 DPU Exh. 5 pp. 5-9 (Weaver)

16 Tr page 2083

17 DPU Exh. 5.0 p. 4

18 Applicants: Present value of $352 million. Steinberg Rebuttal page 4. Division: Base case present value of $346 million. DPU Exh. 5.0 page 20 as corrected from the stand.

timates that the reduction in costs incurred by the Utah division would have present value over $300 million.[19]

SERA adopts a simpler approach consisting of setting out an explicit assumption as to the physical capacity reductions which the merger may permit and costing these at an assumed BPA rate. These (avoided) costs, then, constitute SERA's estimate of capacity savings. This approach, if done right and based on reasonable assumptions, could produce a reasonable approximation to the more detailed analysis discussed above. SERA also projects real and substantial long range capacity savings.[20]

Finally, Goff employs a method not explained in testimony. His conclusion is that the merger will <u>increase</u> capacity costs by over $186 million compared to the sum of the stand alones.[21] Since no methodology description is provided, evaluation of such will not be attempted here. Goff's assumptions will be discussed in the next subsection.

C. Assumptions

The analyses differ on three classes of assumptions: (1) the magnitude of resource requirement reduction, (2) transmission augmentation adequacy, and (3) availability cost of BPA resources for use by the Utah division of the merged company.

1. Resource Requirements Reduction Benefits

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19 Weaver First Rebuttal page 11

20 Present value of between $65 million and $123 million. Weatherwas Surrebuttal page 21

21 Goff direct p. 9

The Applicants adduce three sources of resource requirement reductions to the merger: (1) peak load diversity,[22] (2) reserve requirement reduction,[23] and (3) spinning reserves-load following.[24] No contention has arisen regarding the diversity benefits estimate. The other two issues are discussed below.

a. Reserve Requirement Reduction

Mr. Weatherwax contends that the Applicants will be precluded by the terms of their inter-utility coordination agreements from acquiring resources based on their assumed 200 MW reduction in reserve requirement.[25] The Division has adopted the Applicants' assumption.[26] This adoption reflects the common sense idea that the merged company will be more reliable than either company alone due to its larger size and increased resource diversity. Ignoring this increased reliability is unreasonable.

b. Spinning Reserves-Load Following

Both Weatherwax and Goff take issue with the Applicants' third (load following-based) resource requirement

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22 Approx. 350 MW to 400 MW per year. See R M Boucher Substitute Supplemental Direct Exh. 3.7

23 Minimuum of 200 MW used in this case. See R M Boucher Substitute Supplemental Direct, p. 13

24 40 MW. See R M Boucher Substitute Second Supplemental direct, p. 14

25 SERA report Section 3, pp. 3-13 - 3-17

26 DPU SUBSTITUTE 5.2, p. 8 of 22 lines 31-32

duction estimates.[27] This is a relatively minor issue, but the Applicants have adequately rebutted the CCS and BMT contentions on the basis of a proper understanding of the operation of the automatic generation control (AGC) equipment on the Utah thermal units and the incorporation of AGC in resource acquisition planning.[28] The Division has adopted the Applicants' assumption.

2. Transmission Issues

All parties recognize the merger will require the construction of additional transmission interconnection facilities between the two systems in order to realize both capacity and net power cost savings. The Applicants have advanced a detailed transmission augmentation plan identifying components, costs, and timing which they judge to be marginally adequate to meet these additional interim requirements.[29] Mr. Weatherwax contends that the Applicants' augmentation proposals are inadequate. He also contends that the Applicants failed to include the cost of portions of their augmentation plan in their studies.[30] Both the Applicants and the Division have rebutted Weatherwax's contentions regarding the adequacy and the inclusion of the cost of the proposed transmission augmentations.[31] The basis of the disagreement on the adequacy of the proposed

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27 SERA Report Section 3, pp. 3-11. R P Goff Direct, pp. 6-7

28 DPS Surrebuttal page find it

29 R M Boucher Substitute Second Supplemental, pp. 22-27

30 SEAR Report Section 6 and Weatherwax Rebuttal, pp. 14-20

31 Weaver Rebuttal of Weatherwax, pp. 2-3. R M Boucher Rebuttal of Weaterwax, pp. 2-4

gmentations is that Weatherwax assumes that all power relationships between the Divisions will require simultaneous, same direction transmission of power over the specific augmented transmission components proposed by the Applicants. In realty, much of this power will take the form of displacement of multi-directional flows, of power which can be scheduled on the more convenient resources, and/or transmission on existing facilities. Thus, Weatherwax's simple addition of the MWS of power involved in the various categories of merger benefits and showing that this sum is less than the capacity of the augmented components is simply irrelevant. Also, the costs of all elements he contends were excluded from the analysis were in fact included.

3. Availability and Cost of BPA power for the Utah Division

Critical to the Applicants' and the Division's analysis of capacity savings is the assumption that the merger will make available to the Utah division lower cost resources which would not be available absent the merger.[32] BMT and CCS have advanced three lines of contradictory argument. The first is that inadequate transmission augmentation has been provided. This line is addressed in the preceding subsection. The second, advanced by Mr. Goff, is that the Utah division would be precluded by institutional constraints from accessing BPA resources.[33] The third, advanced by both Goff and Weatherwax, is that the cost of such new BPA resources may be understated and

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[32] DPU Exh. 5.0, p. 3

[33] Goff Direct, p. 8. Goff Rebuttal, pp. 6-8

erefore the capacity savings overstated.[34]

a. Availability

Goff's contention is that BPA power cannot be used outside the Pacific Northwest region by the terms of the legislation controlling BPA and the PP&L BPA Power Purchase Agreement. This contention is unfounded.[35] The heart of the argument is that the Applicants will be able to increase their access to BPA NR power due to (1) their Pacific Northwest regional load growth and (2) reduction in their currently nominated Firm Resources. Utah will then participate in the low cost of these resources, even though the power used in the Utah Division will physically be generated elsewhere.

b. Cost

Both Goff and Weatherwax object to the assumed BPA NR rate as being unrealistically low. These contentions ignore the fact that the BPA NR rates advanced by the Applicants and adopted by the Division are BPA's own middle projection figures. They specifically incorporate a number of new resource possibilities, including major investments in cost-effective conservation, before new coal plant investment is required. Like all projections, these will almost certainly be wrong when compared to actual future BPA rates. There is, however, no reason to expect that they have been badly understated. The error may well go the other way.

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34 Goff Rebuttal, pp. 8-9. Weatherwax Rebuttal, pp. 23-24

35 Weaver Rebuttal of Goff, pp. 1-5

Even if the BPA NR rate ultimately promulgated is based on construction of units equivalent in costs to those of the Utah stand alone thermal units, the benefit is the postponement of the requirement for such units and/or the ability to purchase at lower cost only the amount of capacity needed rather than a whole new unit constitute merged capacity savings as compared to the stand alone case.

d. Conclusions Regarding Capacity Savings

As indicated above, four different projections of base case type capacity savings have been advanced by the parties. Only BMT shows an increase. The others show substantial savings. When Goff's figures are properly interpreted, they also show a decrease in costs to be borne by projected jurisdictional ratepayers.[36] In addition, a number of alternative scenarios were projected by the Applicants and SERA and primarily by the Division.[37] All such alternative scenarios project substantial capacity expansion savings. The Division concludes that in the long run, the most important benefit accruing to the Utah division (and the Utah State jurisdiction) ratepayers will be those in the capacity savings category discussed here. Such benefits should outweigh any uncertainty regarding the magnitude of net power cost savings, as discussed in the next section, in judging the appropriateness of approving the merger in this jurisdiction.

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[36] Weaver Rebuttal of Goff, pp. 5-6

[37] DPU SUBSTITUTE Exh. 5.4

III

POWER COST SAVINGS RESULTING FROM THE MERGER

All parties accepted the production cost model developed by the Applicants, called PD/Mac, for use in estimating net power costs with and without the merger and under various sensitivity assumptions. Thus, the analytical approach is not at issue. Disagreement centers on two categories of issues: (1) attribution of cost reductions to the merger as a benefit not realizable through some form of contract arrangement absent the merger, and (2) specific assumptions to be used to compute net power costs in the stand alone and merged cases (the difference in these two cases constitutes merger benefits).

A. Attribution

The issues here are the same as those addressed above with respect to attribution of capacity savings and will not be restated here.

B. Differing Assumptions Used in Net Power Cost Reduction Merger Benefits Estimation

Mr. Goff rejects most of the Applicants' claimed net power cost reduction benefits based on the non-attribution argument discussed above. His concerns will therefore not be further considered in this section. The Division's analysis consisted of an evaluation of the major assumptions used by the Applicants and development of a sensitivity analysis based on the specification of a number of scenarios. The Division's conclusion was that while some of the specific assumptions may lead to a slight overstatement of cost reductions expected from the merger, their base case is likely to quite closely approximate realizable benefits.[38] The scenario considered included variations on native load growth projections, variations on Utah vs non-Utah coal prices, variations on Pacific Northwest hydro conditions, variations in secondary sale prices, and the elimination of the 100 MW firm off-system sale hypothesis.

The general implication of these scenarios further supports the Division's conclusion that the merger offers real and substantial net power cost reductions. The only scenario showing a substantially lower net power cost reduction is the elimination of the 100 MW firm off-system sale. This sale therefore accounts for approximately one-half of the Applicants' claimed base case net power cost reduction. The Division adopted the "without firm sale" scenario as its low case power costs saving estimate.[39]

Witness Weatherwax criticizes many of the major assumptions used by the Applicants in their base case.[40] Extensive debate occurred among SERA, the Applicants and the Division regarding the merits of Weatherwax's criticisms and the appropriate changes in assumptions, if any, to adopt in correcting for those criticisms. A series of technical conferences were held on May 16 and 17. At these meetings, it was agreed that the Applicants and SERA would prepare a joint exhibit presenting their base cases, the major groups of

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38 DPU Exh. 5.0 pp. 32-33. DPU Exh. 5.5 p.4 (Weaver).

39 DPU Exh. 7.1 line A.5.

40 RKW direct testimony, pp. 10-16. RKW-w Chapters 4 and 5. RKW Rebuttal.

assumption disagreements driving the differences in base cases, and quantifying the impact on net power cost reductions attributable to each group of assumption disagreements. This joint exhibit is marked as Exhibit ____. The joint exhibit shows that the bulk of the difference between the Applicants' and the SERA base case is attributable to differences in treatment of firm off-system sales in the merged and stand alone cases. This is consistent with the Division's sensitivity analysis finding that the 100 MW firm sale is responsible for one-half of the Applicants' base case net power cost savings from the merger. In fact, resolution of this issue in favor of the Applicants' assumptions would be sufficient to eliminate SERA's contention that insufficient savings could be realized to permit the "guaranteed" five percent rate reduction to be cost justified.

The difference between the two positions is that SERA contends that Pacific Power, in the stand alone case, could make a firm sale to the Southwest similar in net revenue impact to that which the Applicants expect to make only as a merged company.[41] To the extent this assumption is correct, the "merger spawned" sale is not a merger benefit. The Applicants[42] and the Division[43] have argued against the reasonableness of the inclusion of such a sale in the near term in a most likely base case. These arguments appear conclusive.

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41 SERA Report, pp. 4-23.

42 Applicant Exh. 22.1, pp. 5-6 (Barker)

43 DPU R 5.3 pp. 4-6 (Weaver)

If the merger spawned sale is in fact made, the issue of the Pacific stand alone sale will matter only as it may affect allocation of net revenues between the divisions. The record in this case indicates that the Applicants do not consider the Pacific stand alone sale to be part of the Pacific stand alone net power cost, so all benefits of the sale would be available for inter-divisional allocation to the revenue requirement reduction benefit of the Utah division. Attention should be focussed on the merger spawned sale rather than the Pacific stand alone sale. While this also is not a certainty--hence the Division's exclusion of it in its low case--it is reasonably likely to occur and to be a significant contributor to Utah division revenue requirement reduction.

As indicated in the joint exhibit, other groups of assumptions explain the remaining difference between the Applicants' and SERA's base cases. These are less significant and are not addressed here individually. The Division has concluded that realized merged company net power cost benefits are likely to be more similar to the Applicants' estimate than that of SERA.[44]

IV

ALLOCATIONS - REGULATORY BURDEN ASSOCIATED WITH THE MERGER

1. Regulatory Burdens

As a result of the merger, there will be increased burdens on regulators in Utah. This regulatory burden is not a

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[44] DPU R Exh. 5.3, p. 9

sis for denial of the merger. First, no insurmountable complexities exist that outweigh the substantial benefits available to Utah through the merger. Second, the Division, in its recommended reporting requirements, has attempted to require the utility to provide sufficient information to permit meaningful regulation. Third, the utility has committed to maintain a sufficient audit trail to permit regulators to track costs within each division and between the two divisions. Finally, if it is ultimately found that regulators have inadequate staffing in order to meet the additional regulatory burden, such a problem should be the basis for reallocating resources or seeking additional legislative staffings, and not the basis for denial of the merger. The additional regulatory burdens associated with the merger comprise one of the non-quantifiable merger detriments. It is, however, in the Division's opinion, an insufficient detriment to outweigh the benefits of the merger.

2. Allocations

The issue of allocations of cost (and in some approaches) benefits between the two divisions has become one of the more controversial issues in this case. BMT and NUCOR are urging the Commission to require the establishment of an allocation methodology prior to the approval of the merger. It is the Division's position that requiring approval of the allocation methodology prior to approval of the merger is unnecessary and could ultimately lead to the failure of the merger.

The proposed procedure to develop allocations is as follows. Within six weeks of the merger, a multi-state allocation task force will be convened. This task force will serve as a forum for the company and each state to convey its thoughts on divisional allocations. Within the first quarter of 1989, the utility will file a jurisdictional revenue requirement and cost of service study, including a proposed method to allocate costs. Sufficient data will be maintained to permit any reasonable allocation methodology. The EBA will be calculated on a stand alone basis, until allocation methodologies are established. In other words, a mechanism has been established to resolve inter-divisional allocations rapidly. The clear implication of requiring inter-divisional allocations to be established prior to the merger is the premise that the Utah jurisdiction will be incapable of protecting its interests in allocating costs between the two divisions. Such a premise is unfounded.

The need to develop detailed inter-jurisdictional allocations prior to the merger is not as essential because the utility has clearly assumed the risk that differing allocation methods between the various states could result in less than full cost recovery. This risk of costs "falling through the cracks" exists currently in allocations among the various states. As a result of the merger, that risk will continue. A condition of the merger should be a clear statement that the utility is ssuming the risk allocation-related of non-full cost recovery.[45] No jurisdiction has required prior approval of allocations. Conditions imposed by one jurisdiction protecting its "turf" could result in each state looking out for its own interest to the ultimate detriment of the utility and other jurisdictions.

Certain broad principles can be established for the allocation process. Dr. Bernow suggested four goals for allocations. Mr. Powell accepted these goals as being reasonable objectives.[46] These four goals are:

a) Clarity of regulatory signals
b) Cost causation linkage
c) Equity and fairness
d) Ease of implementation

The main concern surrounding allocations appears to be the concern that the Utah division will not receive its fair share of reduced allocated costs. Each of the two divisions brings unique resource characteristics to the merger. The Utah division has its unique north-south transmission system. The Pacific division has access to low cost Pacific northwest hydro resources which have lower capital and energy costs than do UP&L's thermal resources. Protection of the interests of the two divisions' ratepayers in these assets is an integral part of any acceptable inter-divisional allocations scheme. The concern on allocations appears to revolve around the ability of regulators

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45 _See_ Huntsman, Condition No. 10 p. 9 of Applicants' response to proposed merger conditions.

46 DPU R 7.5 p.2 (Powell)

allocate power costs between the two divisions.[47] Power costs impose the most difficult allocation problem because they embody the operation of the two unique divisional resources referred to above. In order to minimize system net power costs, the merged company should operate its resources--generators, power purchases, and transmission--without regard to pre-merger ownership of the various assets. If resulting costs are allocated on a traditional cost causation basis, it is possible that diversions of the lower costs associated with the unique division resource would occur. The net effect on each division's revenue requirement is impossible to foresee at this time, but it is extremely unlikely that they would exactly balance. Therefore, some explicit mechanism must be developed to ensure that a fair and equitable allocation of the lower system average cost is achieved. Such a mechanism must ensure that both divisions receive lower net power costs than they would absent the merger, while protecting the unique interests of each division.

The Applicants have recognized this problem and have addressed it with their three model approach. The Committee originally suggested that average net power costs be allocated to

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[47] No one has raised any major concerns on how to allocate existing capital facilities and firm power purchase and sale agreements, new additional facilities of the merged company, and non-power costs. Traditional cost causation allocation procedures can be used to allocate the latter two categories, while continued allocation of existing capital facilities and firm power purchase and sales agreements to the division succeeding the companies now holding them will fairly protect the interests of the division's ratepayers.

each division with some other cost element being adjusted to provide the required protection of unique divisional resources. The Division has taken the position that the merger will provide lower net power costs than would be achieved absent the merger. We have not advanced any specific allocation proposal of our own, but have asserted our confidence that a reasonable allocation mechanism, meeting the purposes set out above and satisfactorily solving the peculiar problems associated with the merger, can be developed. Design and implementation of this system, as the Applicants propose, should be resolved to the extent possible, in a series of inter-jurisdictional meetings. All reasonable allocation schemes should be evaluated in such meetings, including those proposed by the Applicants and the Committee. It is entirely possible that the methodology to allocate power costs between the two divisions has not even been addressed on this record. Finally, it must be emphasized that this Commission has the final authority to establish what it accepts as a reasonable allocation of total PacifiCorp net power costs. The information required to carry out such an allocation of costs is to be collected and maintained by the utility. The allocation problem may well prove difficult to resolve, but it is certainly not insurmountable.

V

LOCAL CONTROL ISSUES (INCLUDING ORGANIZATIONAL STRUCTURE AND FORM, AFFILIATED RELATIONSHIPS, AND FINANCIAL ISSUES, SUCH AS APPROVAL BY THE COMMISSION OF SECURITIES ISSUES, BUDGETS, ETC.)

Local Control

The issue on the loss of local control is largely a "red herring". The merged company has made every effort absent the creation of a separate subsidiary for UP&L to maintain as much local autonomy of the Utah division as is possible. It is inconceivable that just because the utility will be an Oregon corporation that it will ignore approximately 40% of its revenue and assets that will be produced in the Utah division.

2. Organizational Structure and Regulatory Authority

By choosing the divisional structure of the merger rather than creating a holding company, local regulatory jurisdiction will remain unaltered. This Commission will continue to have what regulatory authority it had over UP&L. This will include the approval of the issuance of securities, the approval of dividends, and any other approvals that are currently required of UP&L will continue to be required of the merged company. In fact, since Utah is the largest jurisdiction of the new merged company, many approvals of accounting orders, which previously were required of the Oregon Commission, will now be required of the Utah Commission.

3. Affiliated Relationships

The Division believes its has adequately addressed concerns surrounding increased affiliated relationships of PacifiCorp. None of the conditions proposed by Mr. Huntsman were challenged by the Applicants.[48] With the proposed conditions

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48 See Applicants' Response to Proposed Merger Conditions, pp. 7-10.

ggested by Mr. Huntsman, and accepted by the Applicants, the Commission will be able to adequately monitor the affiliated relationships of Pacific.

VI

EFFECT OF MERGER ON RETAIL PRICES

The ultimate effect of the merger on retail prices will depend on the amount of reduced cost resulting from the merger and how costs are allocated among the jurisdictions. The merged company has committed to a 2% reduction in Utah division revenue requirements within 60 days of the date of the merger, and has committed to a 3% additional reduction in Utah revenue requirements within the next four years. Any additional reductions in Utah revenue requirements will depend on cost of service cases. It is estimated that a 10% reduction in Utah revenue requirements could occur over the next four years as a result of the merger. A concern has been expressed that after the end of the five year period, the utility will raise its rates to reflect cost of service and to reflect the failure of merger benefits to materialize. The Division does not have such a concern.

First, the utility has committed that rates will never go up as a result of the merger. This commitment will only come into play if merger benefits fail. However, it provides this jurisdiction with protection from higher rates as a result of the merger. Therefore, if all merger benefits fail and the 5% rate reduction is in jeopardy, the Utah jurisdiction would be no worse off with the merger than without.

Second, after the conclusion of the five year study period, capacity cost savings associated with the merger begin to become more substantial. All parties (except BMT) appear to recognize that there will be significant capacity related savings associated with the merger. These capacity cost savings are substantial and as significant in present value as the estimated merger benefits during the five year study period. Therefore, it the worst case scenarios do materialize and the 5% reduction is not cost based, merger benefits after the 1992 period will more than make up for any shortfall.

The distribution of the revenue requirement reductions addressed above will be the responsibility of the Utah Commission. In its consideration of this issue, the Commission may or may not impose the same percentage reduction on all classes of ratepayers. Some may benefit more and other less. This is no different from non-merger costs of service costs.

VII

EFFECT OF MERGER ON MAJOR INDUSTRIAL CUSTOMERS

The merger conditions, in large part, suggested by BMT, Nucor and Amax, reflect their own self interests. Their main concern is that the surpluses in capacity they have enjoyed will be eliminated as a result of the merger. As a result of the elimination of excess capacity, interruptible customers may receive a higher incremental costs than they would with excess capacity, and in addition, may be interrupted more often than ey would be with excess capacity.[49] The interruptible customers have developed a variety of conditions designed to protect their own interests. These conditions include:

a) Dispatch priority over new firm and non-firm sales;
b) Retail wheeling;
c) Purchase of surplus energy on the same terms as a utility;
d) Procedures to guarantee that interruptible customers' rates and service; and quality will not be lowered as a result of the merger.

All these conditions should be rejected. These conditions are either unrelated to the merger and could be raised in a separate case or could give an advantage to interruptible customers that have not been guaranteed to firm customers.

IX

COST OF THE MERGER INCLUDING DILUTION

1. $18.5 million costs

As a result of FASB 90, the Applicants requested an order providing accounting treatment of the $18.5 million merger cost. Their proposal is to amortize the $18.5 million over forty years with full rate base treatment on the unamortized balance. The Applicants proposed no split between ratepayers and shareholders of the merger costs. Both the Division and the Committee proposed alternative methods of treating merger-related costs. Both methods were designed to share the costs between ratepayers and shareholders. Such a sharing is warranted because merger benefits flow to both customers and shareholders. The

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49 Excess capacity would be eliminated regardless of the merger. As a result of the merger, the excess capacity of each division is eliminated earlier. Interruptable customers will receive the direct of lower incremental costs.

vision has proposed to amortize the merger costs over the forty year period, but permit no return on equity to the unamortized portion. The Committee, on the other hand, proposed amortizing merger costs over the forth year period, but provides no return on the unamortized portion. The Division recommends its approach for two reasons. First, its approach results in no write-off in 1988 of merger-related costs. The Committee methodology would result in a write-off in 1988 of $14 million. Second, the Division testified that its method would result in a more equitable sharing of merger costs between ratepayers and shareholders.[50]

2. Bond Rating

BMT testified that the potential drop in UP&L bond rating should be recognized as a cost of the merger.[51] No quantification of either the magnitude of this cost or the likelihood of its occurrence was presented. Mr. Colby presented evidence indicating that bond rating agencies believed that any near term erosion in cash flows, interest coverages and capital ratios would be positively reversed as merger savings occur.[52] Mr. Eatmon's analysis of the merged company's liquidity,

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50 See DPU Exh. 7.5 (Powell) pp.5-6. In particular, see Exh. 7.6. This exhibit compares the first year costs of the various alternative write-offs of the $18 million, the net present value of the total costs, and the amount that would need to be written off in 1988. It also should be pointed out that the reasonableness and merger-related cost will be addressed in the rate case in the first quarter of 1989, and it not being addressed in this case.

51 Grow, direct testimony, pp. 15-16

52 Applicant Exh. 8.0 pp.34-35 (Colby)

ofitability and capital structure indicate that the merged company's prospective financial performance will not be inconsistent with Standard & Poor's "A" rating criteria.[53] In addition, since the merged company will require no new bond financing in the near term, no impact on U&PL ratepayers would result from any potential near term credit downrating.[54] Any concerns about potential bond rating downgrades should have been reduced by the recent Duff & Phelps upgrading of the merged company's bond rating to that of UP&L. If such a bond rating continues, Pacific's cost of capital will be lower than it would have been absent the merger.

3. Dilution costs.

BMT testified that the premium paid for UP&L stock could result in adverse impacts on Utah rates. The company admits that dilution in earnings will exist in the near term. Mr. Eatmon has estimated that UP&L's stand alone common share value is approximately $25.89 per share. At a purchase price of $32.25 per share, the premium to existing UP&L shareholders would be $6.36 per share. What regulators must be concerned with is the adequacy of PacifiCorp's cash flows to meet common equity dividend payments and to contribute to the neutralization of the earnings dilution. Mr. Eatmon's analysis indicates that despite paying a premium for UP&L common shares, PacifiCorp's shareholders will be returned a net present valued financial

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53 DPU Exh. 6.0 pp. 65, 67 and 70 (Eatmon)

54 Applicant Exh. 8.0 p. 35 (Colby)

nefit of $160 million, a 15.33% internal rate of return on their original investment. The principle source of these net benefits are the additional free cash flows to be produced by the merger synergies and the ability of PacifiCorp to exploit the merged company's enhanced cash flow position. Thus, while near term earnings dilution will result from the premium payment, near term cash flows of the merged company will provide adequate dividend payment coverage for common shareholders. Mr. Eatmon's analysis indicates UP&L presently possesses excess cash balances of near $100 million. Upon consummation of the merger, these cash balances will serve as an incremental cash reserve for shareholders until the merger synergies impacts begin to produce neutralizing cash flow benefits. As Mr. Eatmon determined, PacifiCorp's recoupment of the premium will result from the merged company's increased ability to earn a fair and reasonable return on equity. This reduction in the premium will come not from inequitable extractions of merger synergies or from excessive equity earnings, but from the ability of the merged company to achieve its authorized rate of return.[55]

X

PROPOSED CONDITIONS (INCLUDING COMMENTS ON COMMITMENTS OR STIPULATIONS AND OTHER JURISDICTIONS)

1. Reporting Requirements, etc. as Conditions to the Merger.

The utility has indicated in its testimony in response to many of the conditions suggested by Mr. Burrup, Mr. Eatmon,

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55 See DPU Exh. 6.0 pp.52-53 (Eatmon) and Mr. Eatmon's sir rebuttal testimony, pp.12-15.

. Huntsman and Dr. Weaver, that reporting and other conditions that could be imposed by the Commission independent of the merger should not be part of the order or conditions in this case. The Division disagrees. The reporting requirements suggested by the Division are intended to provide regulators with the necessary information to regulate the merged company. Putting such requirement up front in the Commission's order approving the merger requires the utility to deal with reporting requirements and affiliated interest relationships in a more structured manner. If the utility wishes to modify a reporting requirement established by the order, it would need to advise the Division and the Commission or the proposed changes and receive approval. We therefore recommend that all of the conditions outlined by the various Division witnesses that deal with reporting, affiliated interests and other types of documentation required to be provided by the merged company be included within the Commission's order.

2. Comments on Some of the Conditions of Other Parties.

Most of the conditions proposed by other parties outlined in Applicants' Response to Proposed Merger Conditions have been discussed in the main body of this brief. This section will provide a brief response to some of those conditions not otherwise addressed in the main body of the brief.

Amax witness Reed proposes that interruptible customers participate in any allocation of revenues from off-system sales. The Division believes that such a condition to the merger is inappropriate.

BMT witness Grow proposes that rate of return should be set without regard to merger premium issues.[56] In the response from the Applicants, they refer to Huntsman's proposed condition #6 which states: . . . agree that the capital costs and structure of the PacifiCorp corporation may be adjusted to reasonable levels to assure that the costs of capital is appropriate for the utility operation." The implication of reference to Mr. Huntsman's condition is that Mr. Huntsman's exhibit resolves the problem addressed by Grow condition #3. That is not correct. The Applicant has acknowledged that the premium paid by PacifiCorp shareholders will not be used as a mechanism to increase the cost of capital for ratepayers, but is instead a risk that the shareholders are willing to assume. Therefore, in calculating rate of return, cost of capital to ratepayers should not be increased because of the dilution in PacifiCorp's shareholders. Therefore, to that extent, the Division believes that Mr. Grow's condition is reasonable.

Grow condition #4 states that the UP&L stand alone model will be updated and revised based upon what UP&L potentially could have done as a separate company. The Applicant's response is that such a condition is unacceptable. The reason they give[57] is that no condition should be imposed which could limit the options available in the meetings on inter-divisional allocations. Although the Division agrees with the

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56 Applicants' Response to Merger Conditions, p.6

57 Id. p.7

sponse by the company, it also agrees that if the stand alone model approach is used in allocating costs, the utility should be obligated to annually revise such a model to reflect what UP&L could have done as a stand alone company, including not filing the merged company's wheeling policy.

Huntsman condition #15[58] has become somewhat confused because of the current status of General Order No. 95. Revisions to General Order No. 95 have been referred to a task force and a report has been submitted to the Commission. However, until new rules are clearly established, it is the Division's recommendation that all transfers of assets between the two division be reported. The company has indicated that there will be little or no transfer of assets between divisions, such a requirement provides the mechanism to assure regulators that utility assets are exchanged between the two division in an appropriate manner.

Condition 1 and 2 of the Committee, although appealing in language are not warranted.[59] In these two conditions, the Committee is attempting to require a guaranteed 10% rate decrease and a 1% increase in rates from 1993 through 1998. Both conditions are modified when global factors come into play. Both conditions go well beyond conditions offered by the company and could well put the merger in jeopardy. If one does not believe that the merger benefits will materialize, it does not appear

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58 Id. p. 10

59 Id. p. 13.

tional to require a 10% rate reduction and a rate cap. It would be better not to approve the merger. If one does have reasonable expectations that merger benefits will materialize, the requirement for annual rate filings will provide the proper mechanism to flow through merger benefits. The concern that the merger could ultimately result in higher rates is protected by the company's certification that Utah customers supported revenue requirements will not ever be raised as a result of the merger. It does not appear appropriate to cap rates or limit reductions by an undefined term such as "global conditions."

Committee condition #5[60] requests that the EBA be calculated on a merged system basis. No rate change is requested until allocations are established. The Division's approach is to request that the EBA be calculated on a stand alone basis until allocation methodologies are established and then to continue to use the EBA or other mechanisms as developed out of the allocation process. It seems both the Committee and Division are attempting to reach the same end. That end is to maintain flexibility in permitting the flow through of merger benefits through the EBA if the allocation process permits it. The Applicant in response to the Committee's condition stated that it was unacceptable. Ultimately, the company should be required to be able to calculate the EBA on both a stand alone and a merged company basis, depending on the methodology ultimately selected for allocations. It is not particularly relevant what

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60 _Id_. at 14

thodology is used to calculate the EBA between now and the adoption of allocation procedures. All that is required is that data be available so that once an allocation procedure is established, the company will be able to retroactively recalculate the EBA from the date of the merger. We would request that the company be capable of calculating the EBA on both the basis suggested by the Division, i.e., a "stand alone" and the basis suggested by the Committee, "merged system".

Committee condition #6[61] has been altered. The company indicates that it does not challenge the condition. However, changes in the language of the condition imply that embedded cost of service studies will not be submitted in the annual filing. As was stated in the Division's condition that requires annual filings, and in testimony of Mr. Powell, the Division expects an embedded cost of service study to be filed the first quarter of 1989, including the cost of service for interruptible and special contract customers. The language of the condition requiring the annual filing should make that clear.

DATED this 3rd day of June, 1988.

/s/ Michael L. Ginsberg
MICHAEL L. GINSBERG
Assistant Attorney General
Tax & Business Regulation Division

61 Id. at 14