

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION)
OF ROCKY MOUNTAIN POWER REQUESTING)
APPROVAL OF AMENDMENTS TO THE)
REVISED PROTOCOL ALLOCATION)
METHODOLOGY)

DOCKET NO. 20000-381-EA-10
RECORD NO. 12624

PRE-FILED DIRECT TESTIMONY OF

Denise Kay Parrish

On Behalf of the Office of Consumer Advocate

Testimony Filed: February 11, 2011
Hearing Begins: April 4, 2011

PUBLIC VERSION

1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 A. My name is Denise Kay Parrish and my business address is 2515 Warren Avenue,
3 Suite 304, Cheyenne, Wyoming 82002.

4
5 **Q. WHAT IS YOUR OCCUPATION?**

6 A. I am currently the Deputy Administrator of the Wyoming Office of Consumer
7 Advocate (OCA), an independent division of the Wyoming Public Service
8 Commission. In this position, I review, provide input regarding, and frequently
9 formulate the recommendations made by the OCA. I review utility applications
10 filed with the Wyoming Public Service Commission (Commission) and provide
11 advice to the Administrator regarding the involvement the OCA should have, if
12 any, in the various cases. I review applications, perform analyses and provide
13 recommendations to the Commission relative to various utility matters, including
14 revenue requirements, rate design, tariff language, competitive issues, rules and
15 regulations, and other items. I perform special studies, as well as provide
16 information and research to customers, the legislature, the OCA Administrator,
17 and others. I do other assignments and tasks, as needed and as assigned by the
18 OCA Administrator.

19
20 **Q. WHAT IS YOUR EDUCATIONAL AND PROFESSIONAL**
21 **BACKGROUND?**

22 A. In 1976, I graduated from Michigan State University with a Bachelor of Arts
23 degree in Accounting. I have spent nearly thirty-four years as a regulator of
24 public utilities, having been on the staff of four state utility regulatory
25 commissions and two consumer advocate entities. More than nineteen of these
26 years have been spent at the Wyoming Public Service Commission, some with the
27 Rates and Pricing Section (now part of the technical advisory staff) and some with
28 the Office of Consumer Advocate. I have taken classes related to various aspects
29 of public utility regulation, including income taxes, regulatory accounting, capital
30 recovery, cost-of-service, rate design, revenue requirements, separations and
31 allocations, and other specialized topics. I have taught classes on issues of

1 accounting standards, general ratemaking principles, affiliate transactions,
2 regulatory accounting, financial reporting, and other specialized topics to
3 regulatory professionals both domestically and internationally.
4

5 Since 2002, I have been a member of the program faculty at the Michigan State
6 University Institute of Public Utilities. I am the current chair of the National
7 Association of Regulatory Utility Commissioners (NARUC) Staff Subcommittee
8 on International Relations. I am the past chair and currently a member of the
9 NARUC Staff Subcommittee on Accounting and Finance. I am a member of the
10 National Association of State Utility Consumer Advocates (NASUCA) Tax and
11 Accounting Committee. I am a member of the Energy Regulators Regional
12 Association (ERRA) Tariff/Pricing Committee. I have also been appointed by
13 NARUC to be member of the International Confederation of Energy Regulators
14 (ICER) Virtual Working Group on Competitiveness and Affordability.
15

16 **Q. DO YOU HAVE EXPERIENCE AS AN EXPERT WITNESS?**

17 A. Yes. I have testified in approximately 200 cases before state and federal
18 regulatory bodies. I have testified before the Michigan Public Service
19 Commission, the Colorado Public Utilities Commission, the Arizona
20 Corporations Commission, the Wyoming Public Service Commission, the
21 Wyoming Legislature Joint Corporations Committee, the Federal Energy
22 Regulatory Commission, and the Federal-State Joint Board on Universal Service.
23 I have testified in telecommunications, water, wastewater, electric, and natural
24 gas cases. The subjects upon which I have testified include revenue requirements,
25 rate design, cost-of-capital, nuclear decommissioning, accounting deferrals,
26 adjustment mechanisms, income taxes, capital recovery, universal service
27 funding, and other specialized topics.
28

29 **Q. WHO DO YOU REPRESENT IN THIS PROCEEDING?**

30 A. As a member of the Office of Consumer Advocate, I represent the interests of
31 Wyoming citizens and all classes of utility customers in this public utility matter,

1 as required by W.S. § 37-2-401. It is neither my intent nor my charge to represent
2 the position of any individual, group, municipality, or corporation.

3
4 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

5 A. The purpose of my testimony is to present the recommendations and concerns of
6 the OCA relative to Rocky Mountain Power's request to revise its
7 interjurisdictional allocation method.

8
9 **Q. ARE YOU SPONSORING ANY SEPARATELY ATTACHED
10 COMPUTATIONAL SCHEDULES OR OTHER EXHIBITS AS PART OF
11 YOUR DIRECT PREFILED TESTIMONY IN THIS PROCEEDING?**

12 A. Yes, I am. I am attaching OCA Exhibit DKP-1 and OCA Exhibit DKP-2.

13
14 OCA Exhibit DKP-1 is information that was publicly shared with Commissioners
15 in discussions of the issues that underlie the application to change the
16 interjurisdictional allocations method. The information was provided at a
17 Commissioners' Forum on MSP held on April 6, 2010.

18
19 OCA Exhibit DKP-2 consists of selected pages from the Standing Neutral's Task
20 and Assignments summary of all the tasks from the early days of the Standing
21 Committee through late 2010. It was widely distributed to those who have been
22 interested and active in interjurisdictional allocations matters.

23
24 **Q. PLEASE PROVIDE SOME HISTORY OF ROCKY MOUNTAIN
25 POWER'S REQUEST IN THIS PROCEEDING.**

26 A. In 1987, Pacific Power and Light and Utah Power and Light proposed to merge
27 into one company. The Applicants anticipated cost savings for both companies
28 including savings from the more efficient use of power plants due to Pacific
29 Power being a winter peaking system and Utah Power being a summer peaking
30 utility. As further detailed at paragraph 18 of the Commission's February 24,
31 1988, Order in Docket Nos. 9266 Sub 104 and 9119 Sub 83 (the merger dockets):

1 Applicants state that their detailed studies are conservatively
2 based, and will result in operating benefits of \$48 million for the
3 initial year of the merged operations, advancing progressively to a
4 total of \$158 million in the fifth year of the merged operation. The
5 fifth-year estimates of benefits are shown to be: \$11 million in net
6 reduced construction; \$17 million from economic development;
7 \$20 million from administration efficiencies; \$53 million from
8 manpower efficiencies; and \$57 million in power supply savings
9 and sales.

10
11 In addition to the summer-winter peaking savings, the order also discusses: better
12 interexchange and movement of power, better access to new wholesale markets,
13 increased flexibility in maintenance of plants, and elimination of duplications.

14
15 More than 20 years later, this discussion of savings is still relevant to the
16 discussion at hand. Much of the debate relative to cost allocations relates to how
17 much of the savings each of the states should receive, as well as how the hydro
18 generation should be shared among the states. Each state has a separate view of
19 what was meant by the statements of the various officials in the original merger
20 case and the debate rages on.

21
22 **Q. DO YOU HAVE SOME ADDITIONAL INSIGHTS FROM THE MERGER**
23 **DOCKETS THAT MAY HAVE SOME RELEVANCE TO THE**
24 **ALLOCATION ISSUES AT HAND?**

25 A. Yes. There was clearly a difference in the average cost of the two companies at
26 the time of the merger with the Utah Power and Light, average costs being the
27 higher of the two companies. However, there appeared to be some anticipation
28 that the differences would be eliminated within a few years after the merger. At
29 paragraph 22 of the Order in the merger dockets, there is a discussion about trying
30 to consolidate the rates of the Wyoming Utah Power customers and the Wyoming
31 Pacific Power in order to eliminate the rate disparities. The provision is:

32 Applicants show that such action taken at this time would unfairly
33 require rate increase to the rates of Pacific Power's Wyoming
34 customers. Applicants state that the consolidation of the Pacific
35 Power and Utah Power properties may be accomplished after the
36 initial five-year term of the merger when the PacifiCorp Oregon

1 Q. Now because you expect that result, and in view of the
2 possibility that you could ultimately see a consolidated
3 company for purposes of setting jurisdictional allocations,
4 do you think that it's possible that an integrated system
5 might result in a simplified method of establishing
6 jurisdictional allocations?
7

8 A. I think clearly a consolidated system would simplify
9 matters from a pricing standpoint. However, that approach
10 as I see it would be patently unfair to the existing Pacific
11 Power & Light Company customers.
12

13 From these statements, it is understandable why many of the parties in
14 Washington and Oregon argue that there was never an intention to immediately (if
15 ever) share all of the hydro generation benefits with both divisions. However,
16 there has frequently been discussion about a natural evolution of the two
17 divisions' costs-of-service coming closer together over time as assets depreciate
18 and are retired and new assets are placed in service.
19

20 **Q. HOW SHOULD THESE DECADES OLD STATEMENTS BE TAKEN**
21 **INTO ACCOUNT AS THE COMMISSION EXAMINES THE ISSUES IN**
22 **THE CURRENT PROCEEDING?**

23 A. Of course, PacifiCorp and its regulators must take into account the changed
24 circumstances that have occurred since the original savings estimates and their
25 associated allocations were first discussed. Time has marched on. The originally
26 anticipated savings have been overtaken by the cost of new investments.
27 Operational changes have occurred. New regulatory requirements have been put
28 in place. Individual state rate decisions have incorporated common costs in
29 different ways. These are all items that must be considered. However, the initial
30 expectations of regulators were established through the testimony of the utilities'
31 executives at the original merger hearings, and for many, those expectations have
32 not changed. Furthermore, the expectations of the regulators across the states
33 were not always consistent, but each may have been supported by a different
34 portion of the original record. The history and those early expectations continue
35 as part of the debate in the current case.

1
2 **Q. DO THE ORIGINAL MERGER ORDERS PROVIDE ANY GUIDANCE AS**
3 **TO THE ALLOCATIONS TO BE USED FOR THE MERGED**
4 **COMPANY?**

5 A. The Wyoming merger order does not provide any specific direction relative to the
6 treatment of interjurisdictional allocations but simply acknowledges that they are
7 an issue. However, the Oregon and Utah merger orders both provide some
8 specific direction including convening multi-jurisdictional meetings within six
9 weeks of the merger to discuss allocation issues. Other directions regarding the
10 future of the cost allocations were more general in nature, in that both the Oregon
11 and Utah merger orders required the use of equitable allocation methods that
12 embodied the principle that incurred costs and revenues should follow or
13 correspond to the cause of such costs and revenues.

14
15 **Q. DID THE ORDERS ALSO DISCUSS WHO WAS TO BEAR THE RISK IF**
16 **THERE WAS DISAGREEMENT ON THE ALLOCATION METHODS TO**
17 **BE USED?**

18 A. Yes. The Utah and Oregon merger orders each have a provision that states that
19 “shareholders will assume all risks that may result from less than full system cost
20 recovery if interdivisional allocation methods differ.” In fairness, shareholders
21 have borne the burden of less than full cost recovery due to allocation differences
22 or allocation rate mitigation plans for more than ten years. One of the primary
23 purposes of this proceeding is to try to eliminate or at least ease that burden that
24 shareholders are bearing.

25
26 The natural follow-up question is: why should regulators and ratepayers care
27 about the burden on the shareholders. The most widely discussed response is in
28 relation to the capital markets. The argument is made that if the cost recovery
29 hole becomes too large, investors will be nervous about recovery of their funds,
30 which will make capital either expensive, or scarce, or both. In theory, this is a
31 reasonable argument, but the size of the cost recovery hole is relevant to the

1 discussion. A hole of \$100s of millions each year is much different than a hole of
2 millions of dollars each year.

3
4 At the April 6, 2010, Commissioners' Forum on MSP, Ms. Becky Wilson of the
5 Utah Public Service Commission Staff made a presentation that attempted to
6 quantify the cost recovery hole. Pages 56, 57, and 61 of the meeting pack from
7 that meeting contains a summary of her conclusions. Relevant to this discussion,
8 she concluded that for the 2005 through 2008 period, using the allocation methods
9 that were in place prior to the adoption of the Revised Protocol agreements left a
10 cost recovery hole of about \$108 million. Yet, changing the method did little to
11 fill that unrecovered cost hole, due to the rate mitigation side agreements that
12 were put into place with the change in the allocation method. With the change to
13 the Revised Protocol method, the unrecovered costs were about \$96 million out of
14 a total of more than \$13 billion for the four year period. The majority of the
15 unrecovered costs remained unrecovered – not because they were unallocated to a
16 state but because there was an agreed cap as to what would be recovered in the
17 retail rates for Utah and Idaho customers.

18
19 Pages 56, 57, and 61 of the meeting pack for the April 6, 2010, Commissioners'
20 Forum on MSP are attached as OCA Exhibit DKP-1.

21
22 Notably, requests for rate mitigation plans relative to the proposed 2010 Protocol
23 are already beginning to appear. On January 27, 2011, in Docket UM 1050
24 before the Oregon Public Service Commission, Dr. George Compton filed
25 testimony on the requested change in the allocation method. One of his
26 recommendations, found on page 34 of his testimony, states:

27 As long as the 2010 Protocol is in effect, the overall cost allocation
28 to Oregon in any year should not depart, positively or negatively,
29 by more than 0.50 percent from what would have been allocated
30 under the Revised Protocol.
31
32

1 **Q. WHAT IS YOUR CONCLUSION RELATIVE TO THE BURDEN**
2 **SHAREHOLDERS HAVE CARRIED REGARDING THE**
3 **UNRECOVERED COST HOLE?**

4 A. My primary conclusion is that it should be just one factor to be examined when
5 determining whether a change in cost allocation methods is necessary at this time.
6 In theory a company should have a reasonable opportunity to recover 100 percent
7 of its reasonably incurred costs. However, this should not be done for its own
8 sake without considering other factors such as the impact on ratepayers, the
9 company's ability to finance even with less than 100 percent recovery, and each
10 jurisdiction's unique circumstances. The theory of complete cost recovery may
11 not coincide with the practice, particularly when providing service in six
12 jurisdictions each with unique regulatory policies.

13
14 In other words, the fear of a problem with the capital markets should not drive the
15 cost allocation decision. Evidence of actually occurring capital market problems
16 would be one factor to consider in the decision to be made in this proceeding.

17
18 **Q. MS. PARRISH, PLEASE BRIEFLY RETURN TO THE HISTORY OF**
19 **COST ALLOCATIONS THAT HAS LED TO THE FILING OF THE**
20 **APPLICATION IN THIS PROCEEDING.**

21 A. Beginning in 1990, a series of interjurisdictional cost allocation agreements were
22 reached among the states. An initial agreement was reached in 1990 (the
23 Consensus Method). For the next decade, there would be periodic tweaks to the
24 allocation method as new situations arose or it was discovered that the allocation
25 method was not working as expected. These various allocation methods included
26 the PITA Accord (with PITA referring to the PacifiCorp Interjurisdictional Task
27 Force on Allocations), and the Modified Accord. The process for reaching
28 agreement on the allocation methods was less formal during the 1990s.
29 Essentially, when the designated staff people from the PacifiCorp retail
30 jurisdictions reached agreement on an allocation method, they each agreed to
31 advocate the use of that allocation method in their next PacifiCorp rate

1 proceeding. The Commissions would then determine the appropriateness of using
2 the agreed-upon allocators as part of the rate proceeding. In some cases, the
3 Commissions did not even formally approve the method but simply approved the
4 rates that came forth from the use of the agreed upon allocators.

5
6 In 1998, the Utah Public Service Commission issued an order adopting the rolled-
7 in allocation method. Under this method, all costs are shared proportionally,
8 primarily based on some agreed-upon mix of each jurisdiction's contribution to
9 the system peak and each jurisdiction's share of total energy. There is no
10 divisional or selected assignment of the common resources to individual states.
11 The Utah move to rolled-in was forewarned to the allocations task force, but the
12 group had not been able to agree to a method that was acceptable to all states,
13 including Utah, so it stepped away from what, up until then, had been common set
14 of allocators. Work continued on trying to find an allocator acceptable to all
15 states. After some time, PacifiCorp saw that common agreement was not eminent,
16 and therefore, it filed an application to restructure itself into six separate state
17 electric companies, a generation company, and a service company. This was
18 referred to as the Structural Realignment Proposal, or SRP.

19
20 In short time, several of the states found the SRP application to be a non-starter.
21 There were several troubling factors, including a shift in some of the currently-
22 held jurisdiction from the states to FERC. This prompted the states to again
23 regroup to see if common ground could be found on allocations, setting aside the
24 SRP filing during the discussions. Years were spent in discussions and with
25 volumes of analyses in order to try to find a common allocation process. That
26 common ground came in the form of the Revised Protocol allocation method.
27 This method and the Stipulation and Agreement regarding its implementation
28 were formally approved in Wyoming with the issuance of the Commission's
29 March 2, 2005, order in Docket No. 20000-EI-02-183. The Revised Protocol is
30 currently the method in use today in PacifiCorp's Wyoming rate cases.

1 Pursuant to the procedures set forth in the Revised Protocol agreement,
2 representatives of the states met on several allocation aspects beginning in 2005.
3 Interested parties met on various matters including examining whether there was
4 any disparity in the treatment of faster growing versus slower growing states.
5 But, there were also opportunities provided to raise questions and concerns about
6 the on-going appropriateness of the Revised Protocol. It was in response to
7 Utah's concern about the actual allocation results compared to its anticipated
8 allocated costs that the immediate application was filed. Utah expressed concern
9 that it was being allocated more costs than it had estimated at the time of the
10 Revised Protocol implementation. It indicated that this was an unacceptable
11 situation, and unless changes were made in the very near future, it would
12 potentially step away from the common allocation process again. During all of
13 these discussions, Utah continued to advocate the use of the rolled-in allocation
14 method -- a method that is more economically advantageous to it than is Revised
15 Protocol. So, again the states regrouped, primarily through the Standing
16 Committee, to again try to formulate a set of common allocators acceptable to the
17 four jurisdictions at the table. The result is the 2010 Protocol proposal.

18
19 **Q. PLEASE PROVIDE A GENERAL OVERVIEW OF THE REVISED**
20 **PROTOCOL METHOD AND CONTRAST IT TO THE 2010 PROTOCOL**
21 **PROPOSAL.**

22 A. The protocol contains a number of definitions, formulas, studies to be undertaken,
23 and process steps for raising concerns about the results. But, to cut to the chase,
24 the key actual allocation elements are:

- 25 ▪ Resources are defined as being in one of four categories: Seasonal,
26 State, System, or Regional.

- 27
28 ▪ Seasonal Resources are then further defined into sub-categories
29 each of which has its own allocator. Since these resources were
30 viewed as being obtained to serve the load of a particular region,
31 division, or area during a particular time of year – generally during

1 the peak for that area – the allocation factors reflect a heavier
2 weighting for those jurisdictions during the months that the
3 Seasonal Resources were most needed.

4
5 For the sake of simplifying the allocation process, and because the
6 result of all of this sub-categorization had little impact on the end
7 result – the proposed 2010 Protocol eliminates the Seasonal
8 Resource category.

- 9
10 ▪ State Resources are those that are put in place or acquired to
11 accommodate state-specific policy preferences, and generally
12 include demand-side management programs (DSM), portfolio
13 standards, and qualifying facilities. DSM costs are assigned to the
14 state driving the cost (situs assigned). Costs associated with
15 meeting portfolio standards that exceed the cost that otherwise
16 would have been incurred are also assigned to the state driving the
17 cost. The high-end portion of the cost related to qualifying
18 facilities is treated in a manner similar to the treatment of excess
19 portfolio standard costs; that is, the cost above the average cost of
20 all other resources is assigned to the state that approved the high
21 qualifying facility rate.

22
23 Changes are proposed in this case to the treatment of the
24 Qualifying Facilities costs. The proposal is to treat existing (as of
25 September 15, 2010) Qualifying Facilities contracts as System
26 Resources. New QF contracts would also be treated as System
27 Resources unless they are priced above comparable resources, in
28 which case the above market portion would be assigned situs. This
29 proposed change has a significant impact on the amount of costs
30 allocated to Wyoming.

1 ▪ System Resources are resources that do not fall into one of the
2 other categories. In general, the fixed costs are allocated on the
3 System Generation (SG) factor which is a weighted factor of 75%
4 system capacity (based on 12 coincident peaks) and 25%
5 temperature adjusted system energy.

6
7 The 75%/25% weighting and the use of the 12 CP is not proposed
8 to change in this case; however, at least one party in Oregon has
9 raised questions about the appropriateness of their on-going use in
10 the allocation process. The weighting as been a topic of discussion
11 for many years and continues as a point of debate. Some want to
12 move toward a more demand based allocator and some want an
13 allocator with a larger energy based weighting.

14
15 ▪ The Regional Resources are the company-owned hydro generation
16 assets and the hydro associated with the Mid-Columbia contracts.
17 These resources are subject to the embedded cost differential
18 (ECD) calculation. For company-owned hydro, the embedded cost
19 differential essentially compares the average cost of all of the other
20 resources of the utility to the cost of the hydro. The benefits are
21 then shared to the old Pacific Power states – Oregon, Washington,
22 California, and Wyoming. For Mid-Columbia hydro, the cost
23 differential between the average cost of the non-hydro resources
24 and the hydro resources is also computed. However, the allocation
25 of that differential (benefit) is based on a complicated formula
26 wherein the benefit associated with each contract has its own
27 allocation formula. Oregon gets the bulk of the benefits from the
28 Mid-Columbia hydro.

29
30 The 2010 Protocol proposes to change the embedded cost
31 differential calculation. One change is to redefine what is

1 considered to be “All Other Resources” when computing the
2 amount of the hydro benefit. The current computation includes the
3 cost of all resources except for the company-owned hydro, the
4 Mid-Columbia Contracts and the existing Qualifying Facilities
5 contracts. The new definition pursuant to the 2010 Protocol would
6 only include resources that were part of the PacifiCorp system
7 prior to 2005.

8
9 A second proposed change is to include the Klamath Settlement
10 costs as a system allocated cost to all states and then offset this
11 cost with a credit to the states that are not obligated to pay the cost
12 under the Klamath Settlement Agreement. The bottom line impact
13 is that Oregon and California pay the Klamath settlement costs;
14 however, including the costs initially (before offset) on a system
15 allocated basis is a move toward rolled-in, which helped to appease
16 some of the concerns of other states.

17
18 Another proposed change is to levelize and fix the dollar amount
19 of the hydro endowment over a six-year period. Under Revised
20 Protocol, the embedded cost differential changes year to year
21 causing uncertainty and variability. But, the hydro endowment
22 under Revised Protocol is also based on actual, known costs, rather
23 than being forecast.

24
25 **Q. AT THE TIME OF THE REVISED PROTOCOL’S IMPLEMENTATION,**
26 **WAS THERE AN ESTIMATE OF ITS RATE IMPACT ON WYOMING**
27 **CUSTOMERS?**

28 A. Yes. As I described on page 33 of my testimony in Docket No. 20000-EO-02-
29 183, the prior cost allocation proceeding:

30 Based on numerous assumptions, and best guesses, PacifiCorp
31 estimates that the net present value change to Wyoming’s revenue
32 requirement will be negligible (about -0.09%). In the early years,

1 the annual impact, all other things being equal, would be to reduce
 2 the revenue requirement by one to two percent. This benefit of a
 3 reduction to revenue requirement is estimated to reverse in about
 4 2011, when the increases would be expected to be one to about one
 5 and one-half percent.

6
 7 Since the impacts are expected to be relatively small, and estimates
 8 will predictably be wrong anyway, the OCA felt no need to request
 9 additional rate mitigation procedures as part of the Stipulation.
 10 Additionally, there is no request to change rates associated with the
 11 approval of this agreement.

12
 13
 14 **Q. WHAT IS THE IMPACT TO THE WYOMING REVENUE**
 15 **REQUIREMENT OF THE 2010 PROTOCOL PROPOSED CHANGES?**

16 A. The impact of the proposed change, as reflected in the pending rate case filing in
 17 Docket No. 20000-384-ER-10, approaches \$10 million, or about 1.51% of
 18 revenue requirement, for the 2011 test year, as shown in Table 1.

19
 20 **TABLE 1**
 21 **COMPARISON OF REVISED PROTOCOL AND 2010 PROTOCOL REVENUE**
 22 **REQUIREMENT IMPACTS**

23 Category	Revised Protocol	2010 Protocol	Difference
24 Operating Revenues	\$663,320,836	\$663,320,836	↓
25 Operating Expenses	\$565,967,947	\$572,147,037	
26 Rate Base	\$1,815,324,570	\$1,814,340,001	
27			
28 Est. Required Increase [RMP figures] 29 <small>((Rate Base * 8.357%) - (Revenues-Expenses)) * 1.62</small>	\$88,053,132	\$97,930,328	\$9,877,196
30 <i>Source: Pages 1.2 and 11.2 of Dickman Exhibit RMP__(BSD-2) in Docket No. 20000-384-ER-10</i>			

31 The majority of the difference between the two allocation methods is in the
 32 embedded cost differential. A comparison of the embedded cost differential
 33 under Revised Protocol and 2010 Protocol is shown below:

TABLE 2
COMPARISON OF EMBEDDED COST DIFFERENTIAL (ECD)

Category	Revised Protocol	2010 Protocol	Cost Increase
Company-Owned Hydro	(\$4,227,142)		
Mid-Columbia Contracts	\$2,127,017		
Existing QF Contracts	(\$6,391,511)		
Levelized ECD Hydro		\$483,919	
Total	(\$8,491,636)	\$483,919	\$8,975,555

Source: Pages 10.9 and 9.23 of Dickman Exhibit RMP__(BSD-2) in Docket No. 20000-384-ER-10

As Table 2 shows, the largest cost difference for Wyoming is the treatment of the Qualifying Facilities contracts as a System Resource rather than as an assigned cost to the state that approved the above-market contract price.

It is also interesting to note that the Hydro embedded cost differential increases costs to Wyoming customers under the 2010 Protocol. One of the most hotly debated issues in allocation discussions is how the costs and benefits associated with the hydro benefits should be distributed among the states. Wyoming is always at the center of these debates, since we were part of the Pacific Power and Light system that brought the hydro with it at the time of the merger, but we do not have the same unmitigated passion about the hydro power as Oregon and Washington parties. Yet, Wyoming continues to be included to some degree in the group of states to whom the hydro embedded cost differential is allocated – except in this case it ends up being a cost rather than a benefit.

Q. DO YOU HAVE AN EXPLANATION AS TO WHY THE HYDRO EMBEDDED COST DIFFERENTIAL HAS GONE FROM BEING A BENEFIT TO A COST FOR WYOMING?

1 A. Part of the reversal may be explained by an increase in expected hydro relicensing
2 costs. Based on information obtained from some data requests in this case
3 (Oregon Citizens' Utility Board (CUB) Data Requests 23 and 25), I have created
4 the following table.

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6 **BEGIN CONFIDENTIAL**

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27 **END CONFIDENTIAL**

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29 Table 3 shows a dramatic increase in expected relicensing costs. I do not have a
30 basis to dispute these cost estimates, but neither do I have a basis for
31 recommending their appropriateness. Yet, these costs have a direct and severe

1 impact on the embedded cost differential and the overall revenue requirement
2 impact related to allocations. As explained in the Company's response to CUB
3 Data Request 34:

4 ...any change in hydro related expenses has a one-to-one impact
5 on the value of the hydro differential if all other ECD components
6 are held constant. For example, if hydro related expenses increase
7 by \$1 million in a given year, the amount of the hydro differential
8 would decrease by \$1 million. To assess the cost impact to a
9 jurisdiction, the change in the differential is allocated by the
10 jurisdiction's DGP factor and the inverse amount is allocated using
11 the jurisdiction's SG factor.
12

13 To illustrate, Wyoming's DGP factor is about 26% so every \$5 million change in
14 hydro expenses would reduce the Embedded Cost Differential benefit by about
15 \$1.3 million for each year of the five-year period containing the levelized ECD.
16

17 It is important to recall that the embedded cost differential is proposed to be
18 forecast, levelized, and then fixed for a five-year period. There is no proposal to
19 true-up these amounts to actual results during the five-year period. Thus, it is as
20 important to understand the forecasts that are used to determine the levelized
21 number. As stated earlier, I do not know how conservative or generous the
22 estimate is. I do know, however, that the whole issue of hydro relicensing costs
23 has been difficult to predict. This is evident by a comparison of prior cost
24 estimates and actual costs, as found on CUB data request 23 (next page):
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TABLE 4
ACTUAL COMPARED TO FORECAST WEST HYDRO
RELICENSING COSTS

	Revenue Requirement - Actual	2004 MSP Study - Forecast
Actual 2006	\$11,807,181	
Actual 2007	\$13,499,557	
Actual 2008	\$15,326,494	
Actual 2009	\$17,600,671	
Forecast Ended March 2007		\$14,136,849
Forecast Ended March 2008		\$24,355,166
Forecast Ended March 2009		\$41,400,634
Forecast Ended March 2010		\$63,954,293

Q. HAVE OTHERS EXPRESSED CONCERN ABOUT THE FORECAST COSTS USED IN THE LEVELIZED EMBEDDED COST DIFFERENTIAL?

A. Yes. In Dr. Compton's January 27, 2011, testimony filed in the current Oregon allocation proceeding, he discusses the issue of the forecasts. On page 25 of his testimony he states:

Q. What would happen if the yearly ECD projections were inaccurate?

A. It would depend on the direction(s) of the error(s). If, for example, the Company over-estimated hydro relicensing costs and/or underestimated the cost of installing enhanced-capability anti-pollution scrubbers on older coal-burning plants, Oregon would suffer from a cost allocation based upon an under-valued hydro endowment.

1 After further discussion of the pros and cons of the forecast inputs, Dr. Compton
2 offers the following discussion and recommendation, as found on pages 30 and 31
3 of his testimony:

4 Q. You are placing a lot of faith in PacifiCorp's modeling forecasts.
5 What if the projections you just cited for Oregon do not pan out –
6 i.e., what if the results depart substantially from what would have
7 been produced by your relative standard of fairness, the Revised
8 Protocol?

9
10 A. First, a comment. Indeed we do place much faith in the integrity
11 of the Company's modeling...But as your question implies,
12 unmitigated reliance upon PacifiCorp's modeling forecasts would
13 be imprudent. Staff's recommendation of support for the 2010
14 Protocol is based, in part, on the Commission adopting the specific
15 protective mechanism regarding forecasts and leveling discussed
16 above...

17 1. A specific protective mechanism: Expressed earlier was
18 Staff's recommendation to substitute year-by-year ECD
19 and Klamath surcharge forecasts for the five-year-
20 forecasted, leveled approach. This approach protects
21 ratepayers from having to rely upon the accuracy of more
22 speculative, distant forecasts. [Footnote omitted.]
23
24

25 I agree with Dr. Compton that there is a forecasting risk in this case – for
26 Wyoming as well as Oregon. It is a much greater forecasting risk than what we
27 normally see in the rate case for a couple of reasons. First, the forecasts in the
28 rate cases are generally only looking forward a year or 18 months compared to the
29 five year look forward that is proposed in this case. And, there is always another
30 rate case waiting in the wings, so if the forecast was wrong, it will not be in rates
31 for very long. Second, there is little or no data provided in PacifiCorp's testimony
32 regarding the inputs of the forecast compared to volumes of data provided in the
33 rate cases.
34

35 I do not agree with Dr. Compton that the Revised Protocol is the measure against
36 which the 2010 Protocol results should be judged, at least it should not be the only
37 measure against which a new proposal is judged. Both the Revised Protocol and
38 the 2010 Protocol are based on a series of compromises and negotiations that are

1 not founded entirely on cost-based principles. Measuring against Revised
2 Protocol is one useful data point but another useful observation would be
3 measuring against Rolled-in or another allocation methodology. As with all
4 things rate related, the observations and data are just useful in allowing the
5 Commission to use its own judgments and conclusions as to what is just and
6 reasonable.

7
8 As to Dr. Compton's recommendation that the forecast, levelized embedded cost
9 differential be replaced with the actual year-by-year costs, that is certainly one
10 reasonable alternative, but it is not without its problems. The use of a levelized
11 forecast was suggested originally to provide some certainty to the parties about
12 the expected impact of the allocations. One of the complaints that has been
13 recurring as the states worked to establish interjurisdictional allocations has been
14 that the formulas put in place do not always provide the expected results. This is
15 one of the primary reasons that the allocation methods were tweaked several times
16 during the 1990s, because the endowment provisions were skewing the results in
17 a way that was unacceptable to one state or another. Thus the idea of locking in an
18 amount and providing certainty was offered as a solution to this problem.

19
20 An alternative protection might be to establish rate caps or boundaries as to the
21 rate impacts that will be found to be acceptable for rate proceedings, shifting the
22 risk that the actual costs will be larger than the forecasts to the utility. However,
23 that circles back to unfilling the cost recovery hole – an issue that has been
24 discussed above.

25
26 **Q. MS. PARRISH, PLEASE EXPLAIN WHY ISSUES AND POSITIONS**
27 **TAKEN IN OREGON SHOULD MATTER TO THE WYOMING**
28 **COMMISSION.**

29 A. The proposed 2010 Protocol states on page 14:

30 The 2010 Protocol has been developed by the parties as an
31 integrated, inter-dependent, organic whole. Therefore, final
32 ratification of the 2010 Protocol by any of the Commission's of

1 Oregon, Utah, Wyoming and Idaho, is expressly conditioned upon
2 similar ratification of the 2010 Protocol by the other mentioned
3 Commissions, without any deletion or alteration of a material term,
4 or the addition of other material terms or conditions...
5

6 In other words, the same allocation methods must be approved in all four states or
7 there is no deal. Thus far, we only have formal positions of the parties in Oregon
8 to review as parties in Utah and Idaho have not yet filed testimony in their
9 companion proceedings. But, it is instructive to note that the three parties that
10 filed testimony in Oregon each have one or more issues with the 2010 Protocol
11 and none recommend approval of the filing as it was submitted by PacifiCorp.
12 So, it appears that either the agreement will not go forward or, more likely, there
13 will be further refinements to the 2010 Protocol that then must come to Wyoming
14 for approval, in which case, it is important to understand the concerns of the other
15 parties in the other states.
16

17 **Q. ARE YOU CONCERNED THAT THE 2010 PROTOCOL IS NOT**
18 **SUSTAINABLE BECAUSE IT IS BASED ON A SERIES OF**
19 **COMPROMISES RATHER THAN ON SOLID, COST-BASED**
20 **PRINCIPLES?**

21 A. Yes. I disagree with those who argue that the Rolled-in allocation method is not a
22 widely-used, cost-based method of allocating common costs. It is a commonly
23 used method accepted by FERC for allocating transmission costs across
24 jurisdictions; one set of costs that are shared based on usage.
25 Telecommunications costs were shared between the interstate and intrastate
26 jurisdictions for decades based on usage studies. One can argue the proportion of
27 demand and energy that should be used in the allocators, but overall, usage has
28 commonly been an allocator of common costs without having to create
29 complicated formulas that are results driven. As has been seen over the past two
30 decades, states demand that formulas be changed when the results are to their
31 disliking. By their very nature, results driven formulas are subject to change as
32 soon as the results show unfavorable results. In contrast, a formula that lets the
33 chips fall where they may –with one state doing better one year and not so well

1 the following year, depending on growth, efficiency measures, etc. – tends to have
2 a longer shelf life. The use of the Rolled-in method would increase the costs
3 allocated to Wyoming by an amount even greater than that attributed to the 2010
4 Protocol, which is one of the reasons that I am reluctant to be much of an
5 advocate for it at this time of already very large proposed rate increases.

6
7 Yet, Wyoming is being asked to adopt an allocation method with a \$10 million a
8 year price increase for each of five years not knowing what happens at the end of
9 that five-year period. It is a step toward nothing, not a transitional cost. If
10 Wyoming was told that at the end of the five-year period, it would be at a
11 permanent solution of x (whether it is rolled-in, hybrid, stand alone or other
12 method), then the cost of moving to that permanent end solution could be better
13 evaluated. But, it is very troubling to think that this charge could increase or
14 decrease dramatically after five years based on the complaint of another state and
15 another lowest-common-denominator solution. Perhaps it would be better to take
16 more time now and see if there is something more permanent that could be
17 derived, or alternatively, determine that the states just need to face the fact that
18 their needs and goals are different and a common allocation method is not in the
19 cards – ever.

20
21 **Q. DOESN'T MR. DUVALL'S TESTIMONY SHOW THAT WYOMING**
22 **WOULD BE WORSE OFF UNDER A GO-IT-ALONE PROPOSAL THAN**
23 **UNDER THE 2010 PROTOCOL?**

24 A. Mr. Duvall's study is rather high level and should not be utilized to reach any
25 ultimate conclusions, and he repeatedly states such in his testimony. However, it
26 would be worth doing a further study of this issue for three reasons:

27 (1) The divergent views of the states are making it less and less
28 likely that a sustainable, common allocation system will be found
29 and a more dramatic solution may be required;

1 (2) The high-level study shows (as found on Mr. Duvall's Exhibit
2 RMP __ (GND-3)) that within 5 years, Wyoming's difference
3 between its non-coincidental peak and the system peak is
4 narrowing and the additional energy resource cost is lessening,
5 thus a more refined look at the cost might make it a feasible option
6 for Wyoming; and

7
8 (3) The Oregon Citizens' Utility Board's preferred approach to
9 allocations is Structural Separation, so we are not the only party
10 with a continuing interest in this method.

11
12 Furthermore, there may be associated benefits from looking at a physical
13 structural separations system. Over the past few years, the OCA has become
14 increasingly concerned that its resource choice informal inputs are becoming lost
15 in the more formal decisions of the other states relative to portfolio policies.
16 Although the issue is relatively moot these days, a few years ago Wyoming
17 entered into some discussions with PacifiCorp and others about the possibility of
18 building more coal plants. However, one of the hurdles that would have had to be
19 jumped was the allocation issue and whether such a plant would have met the
20 definition of a state resource or whether there would have been other allocation
21 issues. While the OCA is a long way from recommending structural separation,
22 we are interested in what benefits and harm might come from being less tied to
23 the resource policies of the other states. Consideration of a structural separations
24 proposal for the allocation process starting after 2016 is worth considering, even
25 if the Commission chooses not to direct such a study at this time in lieu of the
26 2010 Protocol.

27
28 **Q. IS THE ISSUE OF WHAT CONSTITUTES A STATE RESOURCE**
29 **ADDRESSED IN THIS CURRENT DOCKET?**

30 A. Yes and no. Ms. Kelly has indicated to me that she attempted to address the issue
31 of new forms of state resources – such as a Wyoming coal plant -- by including a

1 definition of State-Specific Initiatives on Page 7 of the 2010 Protocol. This is
2 new language that adds to the description of State Resources and the proposed
3 language certainly broadens the types of items that may be included. However,
4 there is still some uncertainty relative to the proposed language as to what is
5 required for something to be a State-specific initiative. For example, does the
6 initiative for feed-in tariffs or electric vehicles have to come from the Governor or
7 the legislature, or is a directive from the Commission or an agreement among the
8 parties adequate to qualify? Some additional clarity of the language would
9 certainly be appreciated and could help to avoid additional debates and arguments
10 in the future.

11
12 **Q. IS THERE ANOTHER CONCERN YOU WISH TO RAISE RELATIVE TO**
13 **BOTH THE 2010 AND REVISED PROTOCOL PROCESSES?**

14 A. Yes and it relates to the Standing Committee process that is described in both the
15 Revised Protocol and the 2010 Protocol. Both Protocol documents include
16 language at Section XIII(C) setting forth the process to be used if a party has a
17 concern about some aspect of the allocation agreement. In short, the concerned
18 party, in particular a party who is prepared to depart from the allocation
19 agreement “will endeavor to cause their concerns to be presented at meetings of
20 the MSP Standing Committee and interested parties from all States” in an attempt
21 to achieve consensus on a proposed resolution of the identified concern.

22
23 Numerous issues have been brought before the Standing Committee over the past
24 five years but they don’t all seem to be treated in an equal manner. Because the
25 Standing Committee appears to try to work on a consensus basis, rather than on a
26 majority rule basis, there have been times when one of the Standing Committee
27 members is not as interested in working on a particular issue, and so it lags in the
28 work process. At other times, if the initiator of the issue is not pushy about
29 having work progress on the matter, then it may lag.

1 For example, in 2008, Idaho raised concerns about the allocation treatment of the
2 costs of its irrigation controllable demand-side management program. But, it is
3 indicated in the Notes/Status column of OCA Exhibit DKP-2, items 133 and 134,
4 the matter was placed on the back burner, and the matter has still not been
5 completed. Now, it is not clear whether there was a misunderstanding about the
6 need to move forward (versus keeping the matter on hold) or whether matters
7 have to reach crisis level for the Standing Committee to actively pursue solutions.
8 I mention both of these possibilities as I have observed both situations with the
9 Standing Committee. Items that need immediate attention tend to dominate the
10 Standing Committee's time, even though if work had been done on the matter
11 when it was first raised, it would not reach the level of having to have an often
12 rushed, immediate decision.

13
14 OCA Exhibit DKP-2 make it clear that a complete list of action items and
15 concerns is being tracked, which is good. But, it also shows that matters brought
16 before the Standing Committee can also take years to process. This is a concern
17 in this proceeding for two reasons. First, the Idaho irrigation issue has now
18 reached the level of need for immediate action, since without an agreed-upon
19 allocation method, a cost-effective demand-side management program may not be
20 pursued this year. Yet, there is no proposal in the 2010 Protocol to address the
21 Idaho irrigation issue. Second, the track record of the slow-moving nature of the
22 Standing Committee and its associated work groups does not bode well for getting
23 a timely review of the 2010 Protocol at the end of its five-year life unless work is
24 started nearly immediately and it would be unfortunate to have to begin a review
25 of the working of the 2010 Protocol (should the Commission choose to approve
26 it) without a reasonable amount of history to see how it is working.

27
28 **Q. WHAT PROCESS HAS BEEN PUT IN PLACE FOR ADDRESSING THE**
29 **ALLOCATIONS BEYOND 2016?**

30 A. None. On page 14 of her testimony, Ms. Kelly proposes an informal method of
31 addressing the post-2016 allocations that starts with the issue being raised at a

1 Standing Committee meeting and letting the Standing Committee take it from
2 there. But, it is not clear what the process would actually be. For example, what
3 if the majority of Standing Committee members agreed to simply continue with
4 the 2010 Protocol (a possibility Ms. Kelly raises) but other parties thought that
5 was a terrible idea because the 2010 Protocol is based on specific cost estimates
6 for the 2011-2016 time period. Would those other parties have to bring a
7 complaint before their respective commissions? What rights would they have to
8 make sure the matter was appropriately reviewed?
9

10 I am not opposed to having post 2016 allocations begin at the collaborative staff
11 level, whether it is a work group meeting or a Standing Committee meeting.
12 However, important matters that have a noticeable impact on customers' rates
13 should have some oversight from the commission(s) and some assurance should be
14 provided that the post-2016 allocations will be subject to appropriate public input
15 and scrutiny.
16

17 **Q. MS. PARRISH, WHAT IS YOUR ULTIMATE RECOMMENDATION TO**
18 **THE COMMISSION IN THE MATTER?**

19 A. Based on the wide variety of problems that have been identified, I cannot
20 recommend to the Commission that approving this application is in the public
21 interest.
22

23 The proposal has a significant price tag associated with it based on undefined
24 and/or forecast assumptions. Meanwhile, the states will have to go back into
25 negotiations very soon to address what to do in 2017, given that the negotiations
26 have a history of taking two to four years to reach agreement. There are issues
27 that have been raised by interested parties before the Standing Committee that
28 have not yet been addressed, particularly the Idaho Irrigation issue.
29

30 However, if the Commission wishes to adopt the 2010 Protocol, it may wish to
31 consider some rate mitigation measures, at least on a temporary or transitional

1 basis. Even if the Commission decides it is in the best interest to approve the
2 2010 Protocol now, it does not have to accept the largest increase of any of the
3 states as part of this process especially based on the perception of some states that
4 it is fair to now charge Wyoming because we received “extra” benefits that were
5 unplanned from adoption of Revised Protocol.

6
7 **Q. DOES THAT COMPLETE YOUR PREFILED, DIRECT TESTIMONY?**

8 A. Yes, it does.

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION)
OF ROCKY MOUNTAIN POWER REQUESTING)
APPROVAL OF AMENDMENTS TO THE) DOCKET NO. 20000-381-EA-10
REVISED PROTOCOL ALLOCATION) RECORD NO. 12624
METHODOLOGY)

AFFIDAVIT, OATH AND VERIFICATION

Denise Kay Parrish (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is the Deputy Administrator of the Wyoming Office of Consumer Advocate which is a party intervenor in this matter pursuant to its Notice of Intervention filed on October 25, 2010.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant’s knowledge, all statements and information contained within the testimony and all of its attached schedules are true and complete and constitute the recommendations of the Affiant in her official capacity as Deputy Administrator of the Wyoming Office of Consumer Advocate.

Further Affiant Sayeth Not.

Dated this 9th day of February, 2011.

Denise Kay Parrish, Deputy Administrator
Wyoming Office of Consumer Advocate
2515 Warren Avenue, Suite 304
Cheyenne, WY 82002
(307) 777-5743
dparri@state.wy.us

STATE OF WYOMING)
) SS:
COUNTY OF LARAMIE)

The foregoing was acknowledged before me by Denise Kay Parrish on this 9th day of September, 2011.
Witness my hand and official seal.

My Commission Expires:
