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Memorandum

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Date: March 5, 2004

Subject: Issues and Alternative Proposals Regarding Docket 02-035-04 *In the Matter of the Application of PacifiCorp for an Investigation of Inter-Jurisdictional Issues: PacifiCorp's Motion for Ratification of Inter-Jurisdictional Cost Allocation Protocol*

I. Issue

On September 30, 2003, PacifiCorp filed its proposed cost allocation methodology termed the "Protocol" method. Subsequent to this filing there have been a number of Technical Conferences to review the allocation changes suggested by the method and to explore other options for a cost allocation methodology in an effort to resolve the cost recovery problem faced by the Company. The following defines our understanding of the issue, our preference for a dynamic approach that incorporates a hydro endowment, an analysis of other expressed solutions including Protocol, and other possible considerations for a modified dynamic approach to allocations.

II. Background

The Division's primary purpose is to find resolution through the collaborative Multi-state Process (MSP) in order to reduce risk to the Company for recovery of legitimate costs. We believe resolution is advantageous to Utah ratepayers as it promotes efficient acquisition of resources as required to provide safe, reliable service at reasonable prices. Early in the MSP process the Division expressed its concern that in the absence of resolution of these issues, the Company has been and will likely remain reluctant to make adequate investment in new resources given its concerns about the risk of cost recovery. Problems with cost recovery have emerged as states have chosen to utilize differing cost allocation methodologies.

Soon after the merger between Utah Power and Light (UPL) and Pacific Power and Light (PPL) in1989, PacifiCorp organized the PITA (PacifiCorp's Interjurisdictional Task Force on Allocations) process attempting to deal with allocation issues among the states. However, looking back it becomes apparent that the states had differing end goals in mind, making resolution impossible. The goal of the Northwest states apparently was to find an allocation method that would preserve the benefits of its hydro resources for the region; while the goal of Utah regulators was to move in a gradual and equitable way to a fully dynamic approach to cost allocations.

A number of methodologies were examined by this group, including, but not limited to, Accord, Modified Accord, and Rolled-In. Under Accord and Modified Accord, the Pacific states were allocated what has been termed a "Hydro Endowment." The Accord method used a load decrement approach, which proved to be problematic leading to Modified Accord and the use of a fuel adjustment. However, there was no general agreement among parties to accept Modified Accord as to the preferred approach. None of the states' Commissions formally adopted any of the allocation methods but would set rates based on the methods that parties had agreed to during the PITA process.

When, in 1997, it became apparent that the PITA process would not result in accomplishing Utah's goal of fully "rolled-in" rates, regulators in Utah opened a specific docket to examine the issue (Docket 97-035-04). The result of the docket was a decision to move to the "Rolled-in" approach. Implementation of the Rolled- in methodology took place under the rate case Docket 97-035-01.[1]

PacifiCorp has continued in its efforts to find solutions to the use of differing allocations methods. In December 2000, PacifiCorp filed its Structural Realignment Proposal. States, in general, rejected this approach, choosing instead to form a Multi-state group to discuss the issues giving rise to different methodologies and seek out potential solutions. Early in the MSP process, it became apparent that the Northwest's goal to retain the benefits of the hydro resources would have to be addressed in order to reach resolution. Two alternatives derived from this process: (1) The Hybrid Method and (2) The Dynamic Alternative. The Pacific states, Oregon and Washington in particular favored the Hybrid approach. The Utah parties developed and favored the Dynamic alternative, which did include a hydro endowment based on a fuel adjustment.

Agreement on a method was not achieved, although parties identified a number of

[1] A substantial refund was warranted based on the evidentiary process in this case. The Utah PSC, rather than refunding the full amount, used a portion ($71 million) to "buy into" the fully dynamic Rolled In allocation. Further discussion of this can been found in the "draft white paper "Utah Power and Light and Pacific Power and Light Merger/Allocations," authored by Doug Kirk and provided at the May 29-30, 2002 MSP meeting in Las Vegas.

components for a potential solution. It was requested by many of the MSP participants that PacifiCorp utilize information gained from the MSP and also from the defined alternative solutions to develop what it considered to be a reasonable resolution. In response, PacifiCorp filed the "Protocol Method" in September 2003.

Today, states are reviewing the Protocol method. The Division in its previous memo dated November 24, 2003 identified key areas of concern with the method. Oregon has also expressed that the Protocol method does not resolve its key issues. [2]

The Division believes that some compromise is necessary to reduce the risk to PacifiCorp for cost recovery so as to remove impediments to necessary resource investments. However, it must be clearly understood that the Division will only support those actions that reasonably provide PacifiCorp an opportunity to earn its allowed return on equity in Utah. In short, we would not support actions that would compensate for a lack of reasonable responses from other jurisdictions. Utah parties generally continue to believe that a fully dynamic approach is the most reasonable way allocate costs across jurisdictions. As a result of different perspectives on these issues, it has been difficult to define a solution that is agreeable to all parties. However, the Division continues to believe that it is possible to define a dynamic approach that reasonably addresses the issues.

III. Benefits of an MSP Resolution

The uncertainty regarding cost recovery is increasingly problematic as PacifiCorp seeks to add new resources to its system. In short, the cost recovery shortfall no longer applies only to embedded resource but also to new resources. Without resolution, cost recovery shortfalls will remain and perhaps become more significant in the near term--continuing to pose problems for PacifiCorp and ultimately ratepayers.

In the recent past, resource inadequacy has in fact harmed ratepayers. During the 2000-2001 market crisis, PacifiCorp was forced to make market purchases at exceedingly high prices in order to meet its obligations. A substantial portion of the costs of these purchases was passed onto ratepayers in both Oregon and Utah.

To mitigate the risk of market volatility, PacifiCorp acquired peaking capacity in the form of owned resources and a leasing arrangement--the Gadsby and West Valley facilities respectively in 2002. Arguably these resources may not have been the most cost efficient options had there been more time to acquire resources. The difficulty was that the PacifiCorp system as a whole was critically short, and the 2000/2001 crisis increased the risk of reliance on the market. Acquisition of these resources did improve the load resource balance for the system and added some of the East-side capacity originally intended as part of the Cholla/APS agreement that was to include the placement of

[2] Reference Oregon Issues Paper filed February 6, 2004.

peaking capacity on the East side of the system. However, the system remains short and new investment is still required.[3]

While PacifiCorp is pursuing various resource acquisitions in the form of self-build and contractual arrangements, the cost of additions could increase if the Company's access to capital markets becomes more restricted as a result of unresolved cost recovery problems. Moreover, the Company has said that its shareholders will be reluctant to take on the risk of either building new resources or acquiring long-term contracts given the current level of cost recovery uncertainty. This could result in less efficient resource acquisitions and increased reliance on the short-term market, which remains volatile. Thus, the Division believes that resolution of the cost recovery problem affording the Company the opportunity to fully recover its prudently incurred costs is in the interest of Utah ratepayers.

In addition, the Division believes that it is important for jurisdictions to accept a common cost allocation methodology. Cost recovery problems today are the result of jurisdictions adopting varying methodologies that do not result in full cost recovery. It has been suggested that simply "closing the hole" for both embedded and future resources is all that is required, and that this can be accomplished even if states adopt different methodologies. However, such a solution would apply to only one scenario and could result in over or under recovery as circumstances change, resulting in an inherently unstable allocations approach.

In response to a Technical Conference data request, the Company provided an analysis of the Net Present Value (NPV) shortfall that would exist under the assumption that Utah and Idaho utilize Rolled-in, California and Wyoming continue to use Modified Accord, and Oregon and Washington adopt the Oregon base case Hybrid approach.[4] The Company studies show that under this scenario it would face a $265 million NPV revenue requirement shortfall under this scenario. In short, this would perpetuate the problem MSP was intended to resolve.

IV. Division Position (Preferred Solution)

The Division supported the dynamic alternative developed by the Utah parties. We continue to believe that a dynamic allocation method that incorporates a hydro endowment is optimal, given the existing policy differences across jurisdiction. Additionally, we believe that consideration for other reasonably defined cost causal adjustments may be warranted. It is the Division's position that a dynamic approach with a hydro endowment supports our goals in this process, including the goal of a reasonable resolution of this issue.

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[3] See the September 30, 2003 Protocol filing, Direct Testimony of Andrew MacRitchie, page 12, lines 10-20.

[4] The assumptions of this approach are included in Oregon's Issues paper filed February 6, 2003.

Our primary objective has been to resolve cost recovery issues in order to promote efficient acquisition of resources. However, we do not believe that resolution should result in unreasonable cost shifts. Additionally, we have promoted a set of decision criteria that we believe support the integrity of the integrated system and the regulatory process. In particular, we have maintained that the ultimate solution should not be overly burdensome to the regulatory process, it should promote continued integrated system operation and planning, and that a benchmark for reasonable cost shifts is defined by the "Fair Share" allocation elucidated in the Company's original SRP filing. The implications of this last criteria is that cost shifts to Utah in any one year be no greater than 2% and that the NPV of any changes in revenue requirement over the 14-year projection period be no more than 2%.

V. Protocol Approach to Resolution

PacifiCorp's filed Protocol method recommended a solution to the cost allocation problems and issues that were addressed during the formal MSP meetings in Las Vegas. The major elements of this proposal and the Division's analysis of each element are discussed below.

Hydro and Coal Endowments (Regional Resources)

Under the Protocol method, certain resources are classified as " regional resources." It is this definition that results in the Protocol-defined hydro endowment as inclusive of all Company owned hydro resources located in the former PPL territory and the Mid-Columbia (Mid-C) contracts. The full costs of the hydro resources, including future relicensing costs are assigned to the West Division states, or the pre-merger PPL territory (Oregon, Eastern Wyoming, California and Washington). To offset the direct assignment of the hydro resources to the West, a "Coal Endowment" is made to the East. This entails assigning all of the costs of the Huntington plant to the Eastern Division, or the pre-merger UPL territory. Thus, the Huntington facility becomes a regional resource specific to the East. Given this method, there is no need for either a fuel adjustment or a load decrement approach for assigning the benefits/costs of these resources to either jurisdiction.

Oregon has indicated that the Protocol method to the Hydro Endowment is not acceptable and also rejects the Coal Endowment.[5] The Division also believes that the Coal Endowment is unacceptable. First, the idea behind the Coal Endowment was that the costs of the Huntington resource closely matched the size of the Hydro Endowment. However, a study done by Commission's advisory staff based on actual 2003 unadjusted results indicated that the cost shift to the East from the assignment of the Huntington costs was nearly double the size of the benefit to the East of not having the costs of the

[5] Reference Oregon Issues paper February 6, 2004.

hydro resources assigned.[6] In part, this is due to the fact that the East bears the fuel costs of Huntington, a positive number, and the West bears the fuel costs of hydro, which is zero. Regardless, it seems that this does not capture the Company's intent of an "equal" offset to the East for the defined Protocol Hydro Endowment.

We are also concerned that the coal endowment is based on a principle in which may be implicit the notion that the East may ultimately be responsible for any and all cost associated with coal-fired facilities. As such, this could gravely impact the sustainability of the Protocol. Thus, we do not consider that a coal endowment represents a sustainable option.

Seasonal Resources

The Protocol recommends reclassifying those resources that can be identified as seasonal in nature, or as "peaking resources," based on operating characteristics or contract defined delivery. Specifically, seasonal resources are Simple-Cycle Combustion Turbines (SCCTs) that are either leased or owned and seasonally defined contracts. The resources falling into this criterion are Gadsby, West Valley and Cholla combined with the APS agreement. For these resources it is recommended that a classification of 100% demand be utilized, rather than the 75% demand-25% energy used for all other resources.

The criterion for classifying resources is defined by the engineering characteristic of the resource. The Protocol rationale for using plant design as the criteria for defining SCCTs as "peaking resources" is that the reason SCCTS are "designed and operated to run during peak-load periods…"[7]

The Division does find merit in the reassignment of certain resources as 100% demand. Specifically, if resources are acquired to meet peaks, then there is a cost-causal basis for allocating those costs more fairly to the jurisdiction(s) causing the peak. While there has been debate that utilizing operating characteristics would be a better method for assigning resources as "peaking," the Division is concerned that this would lead to increased ambiguity regarding the assignment of costs. It would be required in each rate case to evaluate specifically how a resource was operated during the test year, assuming historic test periods. Under future test periods, assumptions would have to be made regarding how plants would operate and would likely be based on an evaluation of past performance.

The Division is concerned that utilizing the criteria of "operating characteristics" could prove to be overly burdensome to the regulatory system and that the benefits of the

[6] Based on the 2003 (April 2002-March 2003) unadjusted results of operation, the Protocol Hydro Endowment results in approximately a $36 million decrease in the Utah revenue requirement, while the Coal endowment results in a $67.8 million increase for a difference of approximately $31.68 million.
[7] Protocol filing, 9-30-03 Direct Testimony of Dave Taylor, page 6.

refinement may not outweigh the increased burden. Thus, the Division believes that the Protocol approach provides a reasonable alternative for improved assignment of costs of the basis of cost causation.

Oregon One-time Opt Out

During the MSP process, some participants from Oregon expressed concern about the future acquisition of coal resources. In particular there was concern that a coal resource may not be the most efficient resource in terms of the next resource acquired. This was also reiterated in Oregon’s overview of PacifiCorp’s 2003 filed IRP.[8]

However, the Division never understood that Oregon participants were requesting a one-time opt out for the next new resource. Rather, Division staff understood that Oregon’s primary concern was related to paying for any new resources that it assessed to be acquired to meet Utah’s growth. In meetings between Division and OPUC staff, it came to be understood that an opt-out for any new resources was Oregon’s goal. Thus, the opt-out proposed by the Protocol did not meet Oregon’s requirement.

We believe that the “opt-out” envisioned by the Protocol, or any type of opt-out for new resources, poses significant future risk and therefore the Division cannot support it. Our concern is that the coal opt out for Oregon will lead to a situation of “over-planning” for the system, or pursuit of less than cost effective resources for the system. As the fuel mix on the East becomes more coal intensive under the proposed protocol, the cost effectiveness analysis for the East changes. With a “heavy coal” resource mix, the risk to the East of accepting another coal facility may be too substantial, resulting in a different resource plan than with potentially higher costs than would have emerged in the absence of the Protocol.

State Resources

State resources consist of Demand-side management (DSM) and Portfolio standards. DSM is currently assigned situs and the Protocol recommends no change for the allocation treatment of these resources. The Division supports that this is reasonable. Decisions regarding DSM initiatives are state specific leading to direct benefits to the state as the allocation of costs falls as result of reduced average and/or peak load growth. There are arguably indirect benefits to other jurisdictions, but the Division believes attempting to track these benefits or assess the value would be overly burdensome to the regulatory process. Additionally, this supports minimizing changes to the current allocation methodology.

The Protocol also defined particular treatment for state Portfolio Standards. In the

[8] This information is based on discussions at the IRP public input meetings and discussions at MSP meetings.

event that the Company is required to acquire state specified resources (quantity, location, type) the portion of costs associated with these resources that is not accepted by other states would be situs assigned to the state enacting the Standards. The Division believes this should hold to the extent that the Company is required to make uneconomic investments as determined by its Integrated Resource Plan.

System Generation Resources

Under the Protocol the majority of the Company's generation resources are categorized as System resources," with the exceptions noted above for "Seasonal," "State," or "Regional" resources. The Protocol proposes that for System resources that there be no change to the current functionalization, classification, or allocation of these resources. In short the recommendation is for continued allocation on the 12-CP, 75/25 criteria currently utilized.

Direct Access

The Protocol treatment of direct access load is consistent with the wall-off approach proposed in the Utah parties' Dynamic Alternative. The Division believes that method is fair and reasonable and provides insulation for other states from the impacts of Oregon's direct access initiatives.

The "Wall-off" proposal contained the following:

1) In the absence of a permanent one-time opt out, Direct access loads would continue to be planned for in the IRP;
2) Since under (1) direct access loads continue to be planned for, these would be included in the jurisdictional load based allocation factors;
3) To the extent that load is lost as a result of direct access, net power costs studies would be utilized to determine the incremental value of the lost load, or in other words, the purchases and sales associated with that load;
4) The value of the lost load would be assigned to the direct access jurisdiction.

The Protocol method uses this approach with two exceptions:

1) Loads lost under a permanent opt-out will be eliminated for IRP purposes, and as such the loads will not be allocated to the jurisdiction;
2) Rather than using net power costs studies to determine incremental values, Direct Access purchases and sales will be tracked and directly assigned to the jurisdiction.[9]

The Division believes that the method proposed by the Protocol is reasonable and

[9] Reference DPU DR 2.32.

fairly simple, which meets our standard of preserving regulatory ease. Additionally, we believe it provides insulation for Utah ratepayers against adverse outcomes associated with another jurisdiction's policy preference regarding direct access.

Transmission costs

The Protocol anticipates that a change in the functionalization of transmission resources will be required under the formation of an RTO and FERC oversight of these organizations. The Division does not support that this change is a given. The exact nature of RTOs and the timing regarding the implementation of such organizations is not known at this time. Thus, we believe any change at this time in either the functionalization of transmission resources or the allocation of costs to meet RTO considerations is not warranted. However, consideration for reallocating transmission costs may be warranted under the case that a Hydro Endowment is established for the Northwest. Further discussion on this issue is contained below in the section "Other Modifications Considered."

Special Contracts

The Protocol method recommends that the costs and revenues of Special contracts be included in host state's revenue requirement on the same basis a would apply to serving any other retail customer. To the extent that the contract provides a discount to the customer for the provision of resource type benefits to the system through interruption of load -- such as operating reserves, support for system integrity, and offsets to new resource investment, the costs of the discount would be allocated on a system basis. Essentially, the Company would treat this "buy-back" of the customers' load similar to the assignment for other ancillary service and/or resource contracts. If the host jurisdiction provides the customer with a discount greater than the benefits associated with defined interruption, the non-cost based portion of the discount would be allocated on a situs basis. In the event that the customer also has a buy-through provision, the costs and revenues of the buy-through would be allocated to the host jurisdiction.

The Division has some concerns regarding the Protocol method for allocating the costs of special contracts. First, in the recent rate case in Utah (Docket 03-2035-02), the Protocol method was used for the assignment of the costs and benefits for a Special Contract customer who provides reserve type interruption. It appears that, in the filing, the contract load of the customer was used to assign the costs of the contract to Utah, but the revenues assigned were based on the actual, or interrupted load. The Division believes that the result is a mismatching of costs and benefits resulting in a "penalty" to the host jurisdiction.

At this time, we continue to support the treatment of Special contracts that was elucidated in the Dynamic Alternative as developed by the Utah parties. We believe that it is important to a) distinguish and value different types of interruption and b) no unduly penalize the host jurisdiction for the simple fact that its Commission approved the contract rate. We are not yet convinced that the Protocol method will allow for reasonable and unbiased valuations of interruption or that it will not result in the host jurisdiction paying the full costs while not enjoying the full benefits of the arrangement. We do, however, agree that any subsidization of the contract via rate discounts in excess of the value of the interruption ought to be the responsibility of the host jurisdiction.

Standing Committee

To promote sustainability, the Protocol recommends formation of a Standing Committee for purposes of addressing inter-jurisdictional issues that may emerge in the future and for consideration of possible amendments to the Protocol. It is further recommended that the Committee consist of one member from each commission.

The issues addressed in the MSP process have been complex. To resolve these issues and promote the objective of the process, the Division recognizes that changes to the current allocation methodology are required. However, a resolution that is ultimately deemed as acceptable to all parties may not incorporate resolution of all of the complex issues explored in the MSP. Moreover, it is likely new issues will arise in the future. Thus, the Division supports the formation of a Standing Committee to provide a forum for addressing the parameters of both new and unresolved issues.

VI. Summary Assessment of Protocol

The Division believes that some elements of the Protocol do warrant consideration. To this end, our approach has focused on identifying reasonable adjustments to the method as filed that support our preference for a dynamic method with a hydro endowment. These considerations are discussed below. The elements were we find merit include the following:

- Adjustments for seasonal resources
- The formation of a standing committee as described by Protocol
- The treatment of Direct Access as developed in the Protocol method
- The treatment of demand-side programs as defined in the Protocol
- The treatment of distribution assets[10]
- The treatment for the gain or loss from the sale of an asset[11]
- The use of load-based dynamic allocators for the treatment of losses or

[10] The Protocol does not recommend any change in the treatment of distribution resources.
[11] The Protocol method is consistent with the method currently used in Utah for the treatment of the sale of a resource and treatment of the gain or loss associated with the sale.

increases to load

Elements we can not support include:

- A coal endowment
- A one-time opt-out for the first new coal resource, or any other opt-out provision
- Any change to the functionalization or allocation method for transmission assets based on unknown RTO outcomes

Areas where we feel additional work and modification are required include the following:

- The defining of hydro endowment and the associated allocation method
- The treatment of special contracts need further refinement to avoid inadvertently penalizing the host jurisdiction
- The treatment of portfolio standards to ensure fair assignment of the cost and benefits of those standards
- Treatment of some currently defined system resources, both transmission and generation, may need to be modified in order to support a hydro endowment

VII. The Hydro Endowment

The issue of whether or not a hydro endowment ought to be established for the former PPL states has been one of the major MSP issues. Oregon and Washington fervently support that a hydro endowment is warranted under the terms of the UPL PPL merger agreements. Utah parties did consider a fuel adjusted hydro endowment in their Dynamic Alternative. However, the issue has not yet been resolved. The Division believes that without consideration of a hydro endowment for the Northwest states, there will not be an MSP resolution. Below, we discuss the considerations, possible methods, and the extent of the hydro endowment.

Consideration of a Hydro Endowment

Through the MSP, the Division has come to understand that the public in the Northwest states believes it is entitled to all the hydropower from that region, at cost. Oregon has expressed that it would not have approved the PPL-UPL merger if it thought that the benefits of these resources would be displaced. Specifically, some Oregon parties have stated that the primary indicator of not being made worse off by joining with UPL seems to be enjoying the undiluted benefits from the low-cost hydropower in the region.

In an effort to reach a resolution in this process, the Division believes that a reasonable solution is one that includes a hydro endowment. In essence, the Northwest states have an expressed regulatory principle to maintain the benefits of certain regional hydro resources. However, it is also the Division's contention that a dynamic allocations methodology is superior to methods that would divide the system or result in fixed allocations of all resources. To resolve these two principled policy objectives derived from different jurisdictions, a dynamic approach inclusive of a hydro endowment is reasonable.

The Regulatory/Allocations Treatment of the Hydro Endowment

Two alternatives for treating the hydro endowment in the allocations process have been discussed in the MSP. The simplest is called the "load decrement" approach. As mentioned previously, one form of this approach was used in the original Accord allocations scheme. Under this general approach, the Northwest was allocated all the hydro costs and all of the hydro output was dedicated to serving its loads. Accordingly, the post-decremented Northwestern loads were used for the purpose of the allocation of the fixed and variable costs of the non-hydro *generation* resources.[12]

The load decrement approach was abandoned in the move from the Accord to Modified Accord when it was discovered that the allocation factors used simultaneously for the generation resources and the non-generation resources were causing distortions in the non-generation costs' allocations. Instead of reformulating the non-generation allocation factors so as to be independent of the generation resources' factors, a major modification to treating the hydro endowment was introduced.

The modified treatment of the hydro endowment was labeled the "fuel (cost) adjustment" method and gave rise to the cost allocation methodology "Modified Accord." This method called for post merger capital investments in hydro facilities to be allocated in a rolled-in fashion across the entire system, while the operating cost advantages would be credited to the Northwest. Under this method, the Northwest would be able to preserve the operating/fuel cost advantages of the hydro facilities, but – unlike the case with the load decrement approach -- would not have to bear the full cost burden of re-licensing.

Fuel Adjustment Method

The Dynamic Alternative as developed by Utah parties supported a fuel adjustment approach related to Company owned hydro only (i.e., exclusive of the Mid-C contracts). The Division supported that this was a reasonable approach, and still considers a fuel adjustment to be a potential method for allocation of the benefits of hydro. However, to date, Oregon has not accepted this approach. Additionally, the

[12] As discussed later, the fatal flaw in the Accord's decrement approach was that the allocations of non-generation resources was distorted due to the inappropriate incorporation into those allocations of the generation resource allocation factors.

Division believes that it might be possible to define a method that more accurately and fairly assigns both the costs and benefits of the hydro resources to Oregon.

The Hydro endowment as proposed in the dynamic alternative expired over time. Once expired, the costs of the hydro system would be fully rolled-in with the other resource costs and dynamically allocated across the system. Thus, the Northwest states would enjoy, for a time, the benefits of the hydro, but ultimately all states would share the costs associated with relicensing, which could be considered an unfair outcome.

It may be possible to modify the fuel adjustment approach to address the issue of the imbalance between the assignment of benefits of the hydro resources and the ultimate increased costs of those resources. For example, the Northwest states could be allocated a higher percentage of the relicensing costs in the later years based on benefits received in earlier years. However, the Division believes it would be very difficult to identify which costs constitute “relicensing” costs. Additionally, the process likely would create disagreements.

Another concern of the Division has to do with the myriad of “reasonable” fuel adjustment options that have been explored. Options vary based on assumptions about what is included in the fuel adjustment and what the basis of the adjustment should be. If only one or two options seemed to make sense, there would be a much better chance for arriving at some kind of consensus among the various parties. As it stands, agreement has not been reached on how the fuel adjustment should be done or if in fact it leads to reasonable outcomes.

It should also be noted that Oregon has expressed that the method utilized in the Utah Parties’ Dynamic alternative did not satisfy the requirement to preserve the benefits of the hydro resources to the former PPL states, for which they would be willing to accept all costs. Thus, utilizing a fuel adjustment approach for the hydro endowment may not result in resolution of the allocations risk that MSP aims to resolve.

Load Decrement Approach

Division staff has looked at the possibilities for utilizing a load decrement approach to allocate the cost of the Pacific hydro resources to the former PPL states. The Division believes that use of a load decrement approach may be reasonable if it can be shown that the risk of any adverse spillover effects from the approach is resolved.

The implication of the load decrement approach is that the loads for the Western Division are first met with hydro resources captured under the endowment. The West would pay the full costs of the hydro resources, receive their total output, and pay for a portion of the remaining production resources that it uses based on its decremented load. The decremented load would correspond to the West’s total load reduced (or decremented) by the amount served by its hydro.

Since the Eastern region would not be allocated any of the lower costs for the hydro-power, it would not be expected to pay for any of the hydro facilities. The Division believes that this is an important consideration in the development of a hydro endowment; namely, that Utah ratepayers do not subsidize hydro benefits received by the Pacific states. Through a load decrement approach, all hydro costs would be allocated to those states, and Utah ratepayers would not be responsible for future costs of relicensing.

PacifiCorp has worked to modify the load decrement method to resolve the problems identified under the Accord method. Specifically, the current load decrement approach modeled by PacifiCorp makes adjustments to allocation factors that seem to eliminate the prior unintended consequences of employing load decrements – e.g., the under-allocation of transmission and general plant to the Northwest.

An area that has yet to be explored is whether employing load decrements will cause the Eastern Division to bear an undue burden regarding the costs relating to the Western Division's increasing requirements that may occur due to growth and/or the need to replace expiring northwestern regional contracts and shrinking hydro capabilities. This matter is discussed in some detail below in the section on "Load Growth."

The Extent of the Endowment

Oregon has expressed that it believes that the costs incurred in the building of dams and in the installation of hydroelectric generators was in anticipation of serving Northwestern, and not Utah or UPL, loads. In other words, the precise cause of the costs of the hydro facilities in the Northwest was the desire to serve loads that are now occurring in that region. Utah loads did not cause the hydro facilities to be installed. On this premise, they argue that a hydro endowment is warranted and should included both Company owned resources and the hydro output acquired through the Company's long-term Mid-Columbia contracts (the Mid-Cs).

The June 12, 2003 memo that was jointly prepared by the major Utah parties and discussed at the July 2003 MSP meetings in Las Vegas acknowledged a limited hydro endowment for the Northwest. But that memo expressly did not recognize the claim that the Mid-C contracts should be treated the same as owned hydro facilities. The Division believes that a strong argument for Utah's position is that the Mid-C contracts were rolled-in as system resources in both the Accord and Modified Accord compacts. The Northwest argues contrarily that the Mid-C hydro contracts are as much a part of that region's patrimony as any of PacifiCorp's own hydro facilities, and that is was only out of the desire to minimize ratepayer expense by signing long-term contracts with government-bonded (and, therefore, having lower capital costs) producers that PacifiCorp (or its predecessor, PPL) did not literally own the Mid-C facilities.

Both sides' arguments have merit. The Division has considered whether or not there is a principled basis for assigning the Mid-C contracts to that region. In response to a data request, the Company provided a brief history of the Mid-C contracts,[13] which consist of the following four separate contractual agreements: 1) The Grant County Priest Rapids Contract; 2) The Grant County Wanapum Agreement; 3) the Douglas County Wells Project; and 4) the Chilean County Rocky Reach Project.

Based on review of that history, it appears that the terms of two of the original contracts specified regional delivery of power. Under the Priest Rapids Grant County contract it was specified that the output from the contracted resources was for the benefit of Oregon customers. The Grant County Wanapum contract specified that the benefits of the low-cost output should accrue to both Oregon and Washington. For these two contracts, there at least appears to be more merit in the argument that these are "regionally specific" hydro resources. However, it must be noted the renegotiated arrangements for these contracts do not specify that the power be for the benefit of consumers in particular PacifiCorp jurisdictions.

Regarding the contracts associated with the Wells and Rocky Reach Projects, the original language did not specify regionally specific delivery of power. It could perhaps be argued that these contracts would not have been entered into had there not existed a regional load that supported the contract expense. The Division does not interpret this, however, indicative of an explicit "regionally specific" load requirement. Rather, the constraints of delivery were specified by the limits of the transmission system rather than any specific contractual arrangement. Thus, it is not clear to the Division that these contracts would not have been pursued under a merged UPL/PPL system.

Revenue Requirement Impacts of A Load Decremented Hydro Endowment

Division staff requested an analysis of the cost shift impacts associated with using the load decrement approach. As a modification to the Protocol the Division requested that PacifiCorp provide an analysis of a load decremented hydro endowment (in conjunction with the removal of the coal endowment). The evaluation indicated that a load decremented hydro exclusive of the Mid-C contracts would result in a net-present-value (or NPV at 8.823%) cost shift of around $70 million, which is about 0.5% of the fourteen-year projected Utah revenue requirement total. When the Mid-C contracts were included the NPV cost shift was an additional $170 million, or about 1.2% of the fourteen-year total.

VIII. Changes to QF Allocation

A possible modification to the Protocol method is the reassignment of Qualifying

[13] DPU Data Request 5.1.

Facilities (QFs) on a situs basis.[14] The theory for making individual states bear the full costs and receive the full output on a load-decrement basis (as with the hydro endowment) is that the individual states ultimately make decisions regarding compensation for the output from the QFs. The rates adopted by the jurisdiction may be at prices significantly above average embedded system costs, but states may choose to do this if it supports other local policy objectives.

Studies indicate that assigning the QF's costs and outputs to their host states reduces Utah's fourteen-year revenue requirement by about $76 million. The combined effect of decrementing hydro and QFs is to increase Utah's revenue requirement by about 1.1% (NPV), with an increase in the first four years of about 3%.[15]

IX. Load Growth

Oregon parties have expressed throughout the MSP concern regarding Utah's load growth. During the formal Las Vegas meetings, Division staff had understood that the primary concern was Utah's peak load growth. This understanding derived from statements regarding the Oregon's resistance to accept costs associated with what it considered to be Summer peaking facilities, namely Gadsby and West Valley. Additionally, the Oregon coalition early in the MSP identified as a potential solution an approach that came to be referred to as the "buckets approach." This method would classify resources as "peaking," "intermediate," and baseload. Peaking units would be classified as 100% demand; intermediate resources would be 75% demand and 25% energy; and baseload resources would be classified as 50% demand and 50% energy. While this option was not pursued, it did contribute to Division staff's understanding that the load growth issue was focused primarily on peak load growth.

Toward the end of the Las Vegas MSP meetings Division staff understood that Oregon was concerned about more than peak load growth and the focus appeared to be on cost shifts associated with Utah growing at a faster than projected rate. Prior to the July 2003 MSP meeting Oregon requested a study examining the cost impacts associated with Utah's load growth being 200 MWs larger than the then current MSP projection. Based on this study, PacifiCorp concluded in its filing that Utah does pick up the majority of its load growth.[16]

In recent discussions with OPUC staff, the Division has come to understand that Oregon's primary concern is that Utah's load is growing at a faster rate than other jurisdictions, with particular emphasis on the difference between Utah and Oregon's

[14] PacifiCorp has noted that it does not oppose the designation of QFs as state resources in the context of an MSP solution (Reference DPU Data Request 2.15).
[15] The 3% is not compounded annually, but represents the average amount by which the electric rates under the Protocol as modified would exceed those in effect under the status quo, rolled-in approach.
[16] September 2003 filed Protocol, direct testimony of Greg Duvall pages 16-17.

currently projected growth rates.[17] Under the assumption that jurisdictions grow at different rates and new resources are added at a cost above average embedded cost, the question is whether or not the cost allocation methodology results in the growing jurisdiction paying for its growth. Some studies have been done to explore this issue, including ones requested by Oregon and Utah as well as in the Company's Protocol filing.

An argument implicit in most of the Company's growth impact studies has been that the high-growth jurisdiction's taking on (under the various rolled-in schemes) a larger share of relatively fixed costs will mitigate in considerable measure the growth burden imposed on the other jurisdictions. Also, system benefits accrue from off-system surplus sales during the period immediately following a new resource acquisition. The conclusion from the growth impact studies has been somewhat ambiguous, with indications that Utah would cover somewhere between less than 80% to more than 100% of the growth costs -- depending upon the shape of the growth, what resources are installed to accommodate it, what the prevailing market prices for natural gas and electricity will be, and what allocations scheme is employed. The study upon which Oregon now places the greatest weight suggests a fourteen-year burden to them of Utah's growth of about $100 million,[18] or about 1.2% of that state's revenue requirement. A joint Oregon staff/Utah Division data request should yield more definitive conclusions regarding the impact of Utah's growth on other jurisdictions under the various allocations approaches

Generally, the Division interprets that the results of most studies to date support that under reasonable scenarios, i.e., with a reasonable matching of resources to load growth, that the costs shifts to other jurisdictions are either minimal and in some cases actually lead to revenue requirement reductions. Moreover, it must be recognized that these results are based on assumptions about future load growth. Load growth projections take the current rates of growth as given and extrapolate these over a planning horizon. Thus, the starting point is key to the assumption that Utah's load growth will continue to be higher than the system average, and at a rate above Oregon's growth. However, jurisdictional load growth tends to be less predictable and more volatile when compared to system load growth. The Division is concerned about making significant changes today to the cost allocation methodology to resolve a problem that may never be realized. Additionally, an integrated system allows for the spreading of the risk of the varying jurisdictional rates of load growth across the system and promotes rate stability for all jurisdictions.

There are also numerous other benefits of integration. At the March 3, 2004

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[17] Oregon's growth rate is projected to be much closer to the system average than is Utah's.
[18] The net present value (NPV) discounted at 8.*823*% was $*90Million*, and discounted at 2% was $*154 million*. The study assumed allocations per the Protocol method. George Compton of the Utah Division collaborated on some technical aspects of this study.

Technical Conference in Utah, PacifiCorp provided a draft discussion paper on the benefits of integration that highlighted a number of system benefits. The following list highlights benefits discussed in that paper that were not already addressed above:

1) There are benefits associated with shared resources that lead to increases in *planning reserves*, allowing the Company to avoid resource additions;[19]
2) The combined system allows for *peak sharing*, further offsetting resource additions;[20]
3) When *load is lost*, the fixed costs associated with the lost load is shared across all jurisdictions and not just spread solely to the ratepayers in the jurisdiction where the load is lost;
4) The integrated system results in a lower revenue requirement than would exists under the case of separate divisions;
5) The combined system provides for a more balanced resource mix, resulting in fuel diversity benefits and a better balance of Company owned and contract resources;
6) The integrated system's transmission network allows for access to markets that would otherwise not be available.

While all benefits of system integration are not quantifiably apparent, the Division agrees that these benefits exist and that any move away from an integrated system would be harmful to ratepayers in all jurisdictions. We also believe that a system solution can be designed to address load growth concerns if such problems can be shown to be consequential.

Moreover, it should be pointed out that a load decrement approach to the hydro endowment would by itself mitigate the impact on the West of load growth in the East. In fact, a potential would be created for the East to be unduly burdened by a combination of Western load growth and the need to bring in new resources to replace retired contracts and post-relicensed, shrunken hydro output in that region. Recall in a dynamic, rolled-in environment that the above-average-costs portion of growth costs are borne in proportion to a jurisdiction's share of the total load or resource pool – i.e., independent of its own load growth. Therefore, by virtue of the decrement adjustment having reduced the Northwest's participation in the general resource pool, the Northwest will end up paying for a smaller-than-otherwise share of its own growth/replacement costs. Whether or not the West's reduced responsibility for paying for its own growth/replacement costs will be fully offset by the recognized burden of having to pay for a portion of the growth/replacement costs in the East will be a function of how closely each region's

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[19] When UPL and PPL merged, the combined Company was able to reduce planning reserves by 240 MW. This allowed the Company to avoid resource additions that would not have been possible without the merger.

[20] The 2005 forecast of the difference between the sum of the divisional peaks and the integrated system peak shows that more than 600 MW of peak can be shared.

share of the growth/replacement requirements compare to its respective proportional allocated share of the non-hydro/QF generation resource pool.

To better understand how the load decrement approach could cause the East to bear an unfair burden of the West's growth/replacement costs, consider an extreme case where the entire Western load could be decremented. Then, when that region grew or caused some resource to be added to replace reduced hydro eligibility, the rest of the system would have to pick up virtually the entire amount by which the cost of the new resource exceeded the embedded average. That is because the West's share of those extraordinary growth costs in the context of a rolled-in dynamic model would be limited to the West's share of the total costs of the non-hydro/QF resource pool.

X. Other Adjustments Considered

The Division has considered other adjustments to the Protocol method that may result in improved fairness of the allocations. Consistent with our recommendation that the assignment of QFs be changed to situs if a hydro endowment is accepted, we have considered modifications associated with the load decrement approach that may improve the method. We have also considered other modifications that may be worth considering as part of a resolution of cost recovery issues. The following highlights some possible refinements we have explored.

Adjustments Associated with the Load Decremented Hydro Endowment

The following three refinements to the load decrement approach may be required to achieve fairness and logical consistency:

1) Hydro resources tend to be more peaking than baseload in nature. The effect of hydro-decrementing the Pacific Division's load will be to reduce their contribution to the monthly peaks more than their contribution to the system's energy needs. This will produce a windfall to that Division in the context of our current 12-CP allocator with a 25%-75% energy-demand classification factor. A recognition that roughly 50% of baseload coal plant's costs are incurred for the purpose of avoiding high natural gas fuel costs of the thermal plant suggests the substitution of a 50%-50% factor for the current 25%-75% factor. Such would reduce, if not eliminate, the just-described windfall.

2) Any administered hydro endowment should not compromise PacifiCorp's integrated system planning and operation.[21] In the context of the hydro endowment (and situs QFs), the balance of the system can be regarded as furnishing the power that can not be obtained from the hydro facilities (and

[21] Operating the hydro system so as to minimize total system costs rather than the Western Division's revenue requirement constitutes a concession to system integration and cost minimization.

QFs). In that light, the allocation of the costs associated with the *non*-hydro/QF facilities should be allocated on the basis of the load conditions that *those* facilities experience. By implication, if the monthly peaks of that residual system are different from the full system's monthly peaks, it is the former that should be used in allocating its own costs. In addition, revisiting the system stress factors based upon the loads incurred by the non-hydro/QF facilities may suggest the substitution of a 6-CP (or other) allocator for the currently used 12CP allocator, so as to better reflect fixed-cost causation.[22]

3) The primary notion behind the load decrementing concept is that the Northwest's jurisdictional retail customers are using the entire hydro and relevant QF output for themselves. That implies that off-system sales – both long-term firm sales-for-resale and load-balancing – are made from the other production resources. Accordingly, revenue credits from off-system sales should only accrue to the former PacifiCorp jurisdictions insofar as they contribute to the cost recovery of those other, non-hydro/QF resources.

Other Modifications

As indicated above, the Division finds merit in allocating the costs of resources that are used heavily in a particular season to the loads that occur in that season. For example, due to the APS exchange commitment, Cholla is not available to supply native loads in the summer. Accordingly, the fixed costs of Cholla are allocated to winter loads. Because Cholla's capacity is insufficient to supply the daily peak APS commitment, additional peaking resources must be acquired to meet that contractual commitment. PacifiCorp's initial Protocol method did not allocate that portion of the summer peaking resource to winter loads (which benefit from the return end of the APS exchange). The Division requested that such a modeling refinement be made.

The Company also modeled another requested Protocol model refinement – this one based upon a Utah PSC staff recommendation. It was to directly assign the Trojan nuclear plant's retirement costs to the Division of its origin, i.e., PPL. The effect was to reduce Utah's fourteen-year revenue requirement NPV by about $12 million.

A third consideration relates to the issue of the specific regional attributes that the former PPL and UPL states brought to the merged system. It is the contention of the PPL states that the hydro resources were, and remain, unique regional resources and that the benefits and costs of those resources should not be lost to those states simply as a result of the merger. The former UPL states believe that a it uniquely provided transmission assets to the system that improved the Pacific states' access to markets --resulting in lower costs in that regard. This notion was explored in the PITA process wherein the

[22] That change would also compensate, appropriately, for the reduction in the peaks, or demand, orientation associated with the energy-demand reclassification described in the previous paragraph.

Accord method derived and applied a “Transmission Endowment.” The Division believes it may again be worth considering establishment an offsetting “transmission endowment” in the East to reduce the revenue requirement impact of the Hydro Endowment. Additionally, the Division believes the endowment is reasonable given that the Eastern transmission system did, and continues to, provide improved market access for the Western Division.[23] In short, there is merit for such an endowment if the wheeling revenues lost due to the need to serve PacifiCorp’s Western Division loads exceed the rolled-in net benefits that the Eastern Division currently receives from the transmission system.

A final consideration has to do with achieving an ultimate compliance with the Utah objective of having revenue requirement increases no greater than 2% in each of the early years. A particular approach may be viewed as acceptable in terms of its long-run revenue requirement NPV effects, but unacceptable due to having to trade large early year burdens for a hoped-for later return. One resolution might be to have PacifiCorp phase-in or defer a portion of the increase on a no-gain-or-loss NPV basis. A caution should be noted, however, in that the corporate discount rate is arguably greater than the social discount rate – meaning that intergenerational equities would be compromised if too large of a future increase were exchanged for a relatively minor level of immediate relief. More appealing, and working with more comparable social discount rates, might be an interjurisdictional “exchange” whereby – again on a neutral NPV basis – one state deferred a decrease (partly on rate stability grounds, i.e., to avoid a larger future increase) so that another state could phase-in its allocation increase in a more palatable manner.

X. The Hybrid Alternative

Considerable time and effort within the MSP was dedicated to the Hybrid approach to inter-jurisdictional cost allocation. The label “Hybrid” owes to its combining a) the direct assignment of generation resources to control areas, with b) a rolled-in/dynamic allocations approach to allocations to the jurisdictions within the control areas.[24] The direct assignment of resources takes on major elements of economic ownership. The “owner” pays its full costs and receives the full benefits, including from the “sale” of power to the other control area when it is short.

The two major reasons for the attractiveness of this approach to the Northwest have been previously described as follows: First, the costs and benefits of that region’s hydro are unambiguously reserved for that region. Second, each region would appear to bear its own growth costs. Other advantages became apparent with the observed large

[23] The Division has requested the Company to undertake an investigation to determine the magnitude and distribution of benefits of the transmission endowment.
[24] The Western Control Area consists of Oregon, Washington, California, and the Jim Bridger generation plant in Wyoming. The Eastern Control Area consists of the Wyoming loads plus the other generation facilities in that state, plus Utah and Idaho.

reduction in the Northwest's modeled revenue requirement as a consequence of altered gas-cost and resource portfolio assumptions.

Utah parties have put forth two major objections to the Hybrid model. One is a concern that its control area focus would create incentives that would militate against system optimization (e.g., as a control area's jurisdictions insisted upon portfolio additions that minimized their own revenue requirements but not necessarily those of the system as a whole). The Company has argued in response that the elimination of fears of subsidizing other jurisdiction's growth will promote more efficient and timely system expansion because of the attendant reduction of the risks of inadequate cost recovery.

The other major concern has to do with interchange accounting, or the mechanism by which a control area that is short compensates the control area that is long when the former receives power from the latter. Since these would not be arms-length market transactions with actual receipts for cash being exchanged for a good or service, auditing and verification becomes problematic. There are two levels of uncertainty. First, rates are based on weather-normalized market/system simulation runs, which incorporate modeled (i.e., formulaic, not actual) market prices. The interchange accounting compensation would be based on those hypothetical market prices. Second, in the subsequent verification analyses based upon "actuals," it can only be inferred that had a true market transaction occurred, the imputed media-posted price (or, more precisely, the average of the two posted prices corresponding to each control area's "market") would have prevailed. It is one thing for two separate utilities to achieve an agreeable method for transacting with each other, and then produce an actual paper trail of their transactions. It is quite another to "simulate" such transactions, but then exchange real dollars between the control areas' ratepayers.

Specific Proposals

Upon PacifiCorp's introduction of its Protocol Method, the technical-understanding sessions that had led to the resolution of many of the issues surrounding the Hybrid Method were halted. The most critical unresolved issue at that time was where to place the Cholla resource and its affiliated APS exchange. Its physical location (Arizona) suggested that it belonged with the Eastern Division. The fact that no power from those resources comes to the Eastern Division when it is most needed (i.e., in the summer), while over 800 average MWs of power are provided in the winter (when the Northwest's peak is achieved), strongly suggests a Western Division assignment.[25]

[25] The two companies entered the merger with reserves at rough parity. Basic equity would suggest that if there is to be the type of "separation" envisioned by Hybrid, then the two control areas should start out with approximately the same levels of reserves. The fact that far more owned capacity (including exchanges) has been added since the merger to meet winter peaks than has been added to meet summer peaks calls into question whether equity in the initial state of a Hybrid approach can possibly be met. Assigning APS-Cholla to the East would exacerbate that Control Area's already "difficult" reserve status. That is because the summer APS exchange obligation *exceeds* the capacity of Cholla -- meaning that the combination of

Given acceptance of the notion that APS-Cholla belongs in the West, a related issue has to do with allocating transmission costs in light of the fact that such a large portion of the inter-control area capacity would be (and is already) taken up by the need to move power from Cholla up to the Northwest. While PacifiCorp has modeled the Hybrid approach with APS-Cholla assigned to the West, no modeling runs have addressed this transmission endowment related concern.

XI. Tiering Method

A desire to further reduce the growth burden experienced by Oregon under the Protocol methods motivated that jurisdiction to suggest a "tiering" approach, whereby pre-2002 plant would be allocated in proportion to the jurisdictions' pre-2002 loads, and the costs of subsequently added resources would be allocated on the basis of the respective increases in the jurisdictions' loads after 2002. This approach has not garnered support in Utah. As mentioned above, the Division is reluctant to make significant changes when the problems at which the change is being directed may never emerge. We believe that more definitive growth-impact studies need to be performed to enable the assessment of the magnitude of the growth-impact problem, and that additional analysis is required regarding how an equitable tiering arrangement might be formulated. We also do not believe that abeyance on this issue at this time should negate opportunities for resolution on other issues that would significantly address the concerns of this and other jurisdictions. Finally, the effects of a number of variations upon the Protocol method are still being explored and that may lead to an implicit resolution of this issue.

XII. Summary

It is the Division's desire that a reasonable and sustainable resolution of the MSP problem be achieved. In order to be both reasonable and sustainable, we believe that a resolution should meet specific criteria. The criteria can be generalized as follows:

(1) The solution should not lead to unfair costs shifts for any jurisdiction;
(2) It should not unduly burden a jurisdiction with regards to timing of revenue requirement impacts;
(3) It should not be so cumbersome that it hinders the effectiveness and efficiency of the regulatory process,
(4) And it should not interfere with integrated integrated system planning and operation.

Our preference continues to be for a dynamic method inclusive of a hydro endowment. We have expressed our recognition of the specific principles upon which the Pacific states base their requirement for a hydro endowment. We also recognize that

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Cholla and the APS exchange *subtracts* from the summer reserves.

the Pacific states believe this claim extends to both Company-owned and certain contracted resources. We have stated previously that we understand that the principle of regionally specific considerations can be applied to the Company-owned resources. At this time, we also recognize that an argument may be made for part of the Mid-C contracts. However, we have not fully analyzed this issue. As we have previously stated in the MSP, it is not clear that PacifiCorp's jurisdictions have any latitude over the dispensation of the resources used to meet the Mid-C contracts; rather, the control lies with the owners of those resources. Thus, the principle that decisions regarding these resources are uniquely related to local socio-economic considerations and should be managed within those jurisdictions is not as transparent as with Company-owned facilities. Thus, we believe that if a hydro-endowment inclusive of the Mid-C contracts is adopted, that there should be offsetting modifications. Two modifications we have explored and believe may be supportable are (1) the situs assignment of QFs and (2) the derivation of a transmission endowment.

In exploration of a resolution meeting our criteria, we have evaluated and considered a number of modifications to the Protocol method as filed by PacifiCorp. Modifications we have explored that could result in a reasonable alternative to the current Rolled-in cost allocation methodology include the following:

1) Elimination of the Protocol-defined Hydro endowment;
2) Elimination of the Coal endowment;
3) Use of a load decrement approach to determine a hydro endowment
    a) for Company-owned resource only
    b) Inclusive of the Mid-C contracts
4) Situs assignment of QFs based on the load decrement approach;
5) Reassignment of the Trojan costs to the Pacific states;
6) Development of a transmission endowment
7) A possible change in the classification and allocation of some generation facilities;
8) Connect off-system sales credits with the generation facilities that provide for them – to be consistent with the notion that hydro generation under a load-decrement approach is dedicated solely to native jurisdiction loads.

The attached tables show on an annual and NPV basis the combined revenue requirement impacts of adopting the first five of those modifications to the Company's basic Protocol model. Comparisons are made to the Rolled-In and Modified Accord outcomes. For comparative convenience, also shown are the outcomes of applying a version of the Hybrid with APS-Cholla in the West and the Rolled-in allocation method with a temporary fuel adjustment that was suggested earlier by the combined Utah parties.

We note that a solution need not be abandoned if it does not at first glance appear to meet the criterion of cost shifts no greater than fair share in any year. If agreement can be reached on the principles and mechanisms of the solution, we believe there would be opportunities to levelize annual impacts.

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