State of Utah
DEPARTMENT OF COMMERCE
Committee of Consumer Services

To: PacifiCorp and Multistate Participants

From: Utah CCS MSP Team

Date: 20 May 2003

Subject: Utah CCS observations regarding interchange energy accounting proposals and GRID simulation modeling as the basis for interchange accounting

1 INTRODUCTION

A current task under the Hybrid approach to resolving inter-jurisdictional cost allocation issues is to develop interchange accounting rules that provide states with independence in pursuing energy policy while reflecting the cost-causation of a prudently planned and operated system. While the Utah Committee of Consumer Services has serious concerns with the Hybrid method in general, the purpose of this memo is to address the practicality and the implications for fairness and rate stability of the interchange accounting approaches currently being considered. These concerns are not fully developed, but we thought it would be appropriate and useful to articulate their nature earlier rather than later.

In this memo we discuss two broad categories of issues, the equity and reality of the interchange accounting methods currently proposed, and the practicality of implementing the Hybrid approach using available information and modeling tools.

2 INTERCHANGE ACCOUNTING ISSUES

In this section we offer specific observations regarding the three proposed interchange accounting methods and other problems of concept, equity and consistency.

2.1 Interchange Accounting Methods

The Hybrid approach to inter-jurisdictional cost allocation, as PacifiCorp has developed it, requires a step that PacifiCorp refers to as “interchange energy accounting.”[1] PacifiCorp has proposed three methods for separating internal interchange from external system-balancing transactions (the Interchange Methods), and three methods for pricing interchange. We have concerns about the equity and realism of both steps.

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[1] If the energy exchanges are between separate corporate entities then they would be a type of wholesale transaction made under a system agreement, and referred to as “interchange energy.” With PacifiCorp and the “Hybrid approach,” these are really “hourly energy cost allocations” within a single Company, but among jurisdictions in which that Company operates. The two situations are analogous in many respects, but quite distinct in terms of corporate structure and regulatory jurisdiction.

2.1.1 Access to Markets for Balancing

PacifiCorp has proposed that the Western Control Area (West) would have primary access to the Mid-Columbia and California-Oregon Border markets, while the Eastern Control Area (East) would have primary access only to the Desert Southwest. Under Interchange Methods 1 and 2, “primary access” means that the control area gets access to its markets first, and the other control area gets access to what is left over. Under Interchange Method 3, all system balancing is attributed to the control area with primary access.

None of these approaches fairly represent the current situation or the topology expressed by GRID. Both the Eastern and Western Control areas have direct transmission connections with Mid-C. Therefore, East should have access to Mid-C on the same basis as West. If Mid-C were over-subscribed, the system balancing could be allocated between the control areas in proportion to their transmission access.

The modeling of SP15 also appears inequitable. Why was East was not given full access to interchange with SP15 when it bears the burden of serving the SP15 contract? It seems particularly inequitable to burden East with the costs of serving the SP15 contract and relieve West of the burden of meeting that load without giving East any related benefit.

More broadly, since all loads pay for all transmission, we believe both control areas should have equal access to all markets in PacifiCorp’s interchange accounting proposals. While FERC rules do not apply to interchange, it is clear that FERC would not allow discrimination in market access between entities that are paying equally for transmission.

In order to treat both sides fairly, PacifiCorp should develop at least one interchange methodology that allocates system balancing without regard to proximity (although obviously transmission constraints must be reflected). One approach would be to allocate all market purchases between the control areas in proportion to their net purchases and allocate all sales in proportion to net sales. If one control area is short and the other long, the first could purchase from the lowest-cost market (or a mix of markets from which PacifiCorp is purchasing), while the other could sell to the highest-priced market (or a mix of markets to which PacifiCorp is selling). Exploring other variants on open-access interchange accounting may also be appropriate.

The process of developing and negotiating a fair system for accounting for system-balancing may take some time; until PacifiCorp develops its proposal(s) and the parties review them, we cannot know whether one option will easily find acceptance. The resulting method may be somewhat more complex than the options PacifiCorp has proposed, but the incremental complexity would be small compared to the complexity inherent in the Hybrid system and the interchange proposals’ reliance on market prices.

2.1.2 Inequitable Market Access in PacifiCorp’s Pricing Proposals

PacifiCorp proposes using the prices of the markets to which each control area is connected to determine the price of interchange. It offers three pricing alternatives: the seller’s maximum price, the buyer's minimum price, or both.[2] We are concerned with the equity and realism of the proposals. We address equity in this section and realism in the next.

The problem of equity arises from West's link to two markets while East is linked to one. So the pricing of interchange at the minimum price of a market on the buyer's side or the maximum price of a market on the seller's side can only assist West. This is true under all three of PacifiCorp's pricing methods.

- Under Pricing Method 1 (seller's maximum), East charges West one price, while West charges East the higher of two prices. Of the six possible orders of prices at the three markets, East pays the middle price in two cases and the maximum price in four cases, while West pays the minimum, middle and maximum price in two cases each.
- Under Pricing Method 2 (buyer's minimum), East pays West one price, while West pays East the lower of two prices. Of the six possible orders of prices at the three markets, East pays the minimum, middle and maximum price in two cases each, while West pays the minimum price in four cases and the middle price in two cases.
- Under Pricing Method 3 (the average of buyer's minimum and seller's maximum), as a seller East is paid the average of DSW and the *minimum* of COB and Mid-C, while as a buyer East pays the average of DSW and the *maximum* of COB and Mid-C.

The PacifiCorp approaches to the Hybrid model cannot be equitable unless the use of market prices for interchange pricing is equitable. The equity of the PacifiCorp approaches could be increased by some combination of the following changes.

- PacifiCorp's proposal for interchange pricing should at least be revised to include in East's markets both Mid-C and SP15, since the Eastern control area has direct transmission to each of these areas.[3] The use of SP15 for pricing East's interchange to West may be more important than the actual sales from East to SP15.
- In addition, it appears that PacifiCorp has access to at least one additional market area (Ault Colorado) and that the Desert Southwest is comprised of three market areas (Four Corners, Palo Verde and Mead) with different published prices. While prices in these areas tend to be fairly close, including the separate prices in the computation of the East's minimum or maximum price would help balance West's access to two markets with greater price differentials.
- In Interchange Methods 1 and 2 (as well as in a non-discriminatory approach we describe above), both control areas can buy and sell to the markets on the other side. Rather than pricing interchange based on arbitrary locational considerations, it may be more appropriate to base interchange prices on the prices of the markets with which each control area is conducting system balancing, rather than just the market(s) on one side.

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[2] The "seller" is the energy-supplying control area, and the "buyer" is the energy-consuming control area.

[3] We discuss in §2.7 below the importance of reflecting the costs of non-firm transmission.

The first approach would have only a small effect on the complexity of PacifiCorp's proposed interchange pricing. The second option would require PacifiCorp to project the prices at additional market hubs and estimate transmission capacity with four separate markets. The third option would not require any additional price projections, but would require somewhat more complicated interchange-pricing logic than PacifiCorp's current proposals, since the pricing program would need to base interchange prices on the markets with which the control area is engaged in system balancing, which will vary from hour to hour. The most realistic and equitable pricing would probably use all three corrections.

2.1.3 Realism of PacifiCorp's Pricing Proposals

The logic of using the price in the adjoining market hubs to determine the control area price in PacifiCorp's pricing proposals seems to be that if the seller were not interchanging to the buyer, the seller would sell more to the higher-priced market on its side and the buyer would buy from the lower-priced market on its side.[4] These assumptions may be unrealistic in a number of specific situations:

- If the seller were selling to both its markets, its response to ending interchange would not be to sell more to the higher-priced market (which it would be doing anyway, if it could) but to the lower-priced market.[5]
- If the buyer were also buying from both of its markets, its response to ending interchange would not be to buy more from the lower-priced market (which it would be doing anyway, if it could) but from the higher-priced market.[6]

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[4] We discussed in §2.1.2 the problems of defining two markets for one control area and one for the other, of identifying the markets relevant for each control area, and of discrimination in access to markets. For the purpose of this point, we will assume that whatever control area is being discussed has access to two markets.

[5] This situation occurs in Case #4 of the fourteen cases distributed for the April 2, 2003 Boise meeting on the Hybrid model (hereafter, the "14 Cases"). The lines to COB are fully loaded, but PacifiCorp prices interchange at West's seller's price of the $40.65/MWh price at COB, rather than the lower feasible price of $32.09 at Mid-C. Case #5 similarly involves using the price of the fully-loaded transmission to COB when West is interchanging to the East (at least in Interchange Methods 1 and 3). In Cases #6, 7 and 10, transmission from West to Mid-C is full and West is interchanging to the East, so PacifiCorp uses Mid-C as the Seller's price for interchange, even though no more sales are possible (in some cases and interchange methods, West could increase sales to Mid-C if it were not interchanging to East, but not by the full amount of interchange).

The same problems occur in the April 24 "14 Hourly Examples from MSP Study 47.4" ("Revised 14 Cases"). (Indeed, pricing in 12 of the 14 cases conflict with reality in one or more respects.) In ten cases (#1, 2, 4, 5, 7, 8, 9, 10, 12, and 13), West is interchanging to East, transmission to the higher-priced western market is fully loaded, and PacifiCorp prices interchange at that higher price, even though ending the interchange would not allow West to sell more to that market.

[6] In Case #11 of the 14 Cases, the transmission from COB is full, and East is exchanging to West. PacifiCorp uses the COB price to set the buyer's price for replacing the interchange, even though no additional purchases from COB are possible. The same is true in Case #3 of the Revised 14 Cases, except that Mid-C is the higher-priced market and transmission to Mid-C is full.

- If the seller is buying from one (low-priced) market and selling to the other (high-priced) market, one of the transmission interfaces must be fully loaded (or else more energy would flow from the low-priced market through PacifiCorp to the high-priced market). If the constrained transmission interface is from the low-priced market, the end of interchange would allow the seller to sell more to the high-priced market, and PacifiCorp's seller-maximum method would be realistic. But if the constrained transmission interface is the interface to the high-priced market, the end of interchange would only allow the seller to buy less from the lower-priced market, and PacifiCorp's seller-maximum method would make no sense.
- Similarly, the buyer may be buying from one (low-priced) market and selling to the other (high-priced) market, with one of the transmission interfaces fully loaded. If not for interchange, the buyer would either buy more from the low-priced market (if the transmission constraint is on the high-priced market) or sell more to the high-priced market (if the transmission constraint is on the low-priced market). In the first case, PacifiCorp's buyer-minimum low-priced method would reflect reality. In the second case, that method makes no sense.

At the very least, the interchange pricing method must correct these errors.

More generally, the PacifiCorp approach applies market price for interchange without regard for the feasibility of changes in transactions with markets across fully-loaded transmission interfaces. For example,

- Suppose that power is flowing from the Eastern control area to DSW and also across the Western interface (with at least some of the power treated as interchange to the Western control area). If the transmission interface to DSW is fully loaded, interchange is not taking energy that the Eastern control area could sell to DSW. Yet PacifiCorp would use the price at DSW to price the interchange in Pricing Method 1 (seller's maximum) and Method 3 (the average).[7]
- Conversely, the Eastern control area could be buying from DSW and receiving interchange from the West, with the DSW interface fully loaded. The price at DSW is once again irrelevant to pricing interchange, since reducing interchange would not increase purchases from DSW. PacifiCorp would use that price in Pricing Methods 2 and 3.[8]
- Even if the transmission interfaces are not fully loaded with interchange, the remaining capacity may be less than the interchange, so that the market price is relevant for some portion of the interchange, but not for all of it. For example, East may be interchanging 400 MW to the West through Idaho, while West is selling 567 MW to Mid-C (the full transmission capacity) at $35/MWh and buying 102 MW from COB at $30/MWh.[9] The value of the interchange to the West is the avoided cost of

[7] Exactly that situation occurs in Case #12 of the 14 Cases.

[8] That happens in Case #8 of the 14 Cases, and in Cases # 1, 5, 7, and 8 of the Revised 14 Cases.

[9] For simplicity, this example assumes that the system balancing with the western markets is attributed to the West control area.

100 MW of additional purchases from COB, to fill the transmission interface, and the value of 300 MW of the sales to Mid-C (which would not be possible without the interchange). The total value is thus $30 × 100 + $35 × 300 = $13,500, rather than the $30 × 400 = $12,000 that PacifiCorp would attribute to the interchange at the buyer's minimum price.

The failure to recognize transmission constraints is part of a more general problem in PacifiCorp's approaches to pricing interchange: the exclusive reliance on market prices, without any consideration of the marginal, incremental, or decremental costs used in most interchange arrangements. The assumptions in the GRID model appear to ensure that market prices will set the marginal cost except when transmission is constrained.

- When the selling control area is purchasing as much as is possible from the market, its incremental cost to supply the interchange may be the higher marginal cost of the seller's own resources. For example, East may be buying the full feasible 405 MW from the DSW at $25/MWh, and running gas plants at $30/MWh to serve interchange to the West. PacifiCorp would charge the East the costs of the gas, and credit it only with the costs of the DSW market (under Pricing Methods 1 and 3).
- When the selling control area is selling as much as it can to the market, and running lower-cost generation to make those sales and to provide interchange, reducing interchange would again avoid the marginal cost of the seller's resources, not the market cost.[10]
- When the buying area is buying all the market energy it can, reducing interchange would require the buyer to run its own more-expensive resources. Yet PacifiCorp's methods 1 and 3 would charge the buyer as though more power were available from the market.[11]
- When the buyer is selling as much as it can to the market, and running less expensive generation to make those sales, the buyer may respond to reducing interchange might just require to increase the amount of the less-expensive generation it is running.[12]

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[10] In Case #13 of the 14 Cases, West's transmission to both Mid-C and COB is full, as is East's transmission to Mid-C, and West is interchanging to the East. If not for the interchange, West would have no additional sales options, and would turn down some generation. In Cases # 2, 6, and 10 of the Revised 14 Cases, West's transmission to both of its markets is full, so the benefit to West of reduced interchange would be the costs avoided by turning down some generation, at a saving less than the price at the lower-priced market.

[11] This happens in Case #8 of the 14 Cases, with the lines from DSW fully loaded and East interchanging from West. It also happens in Case #3 of the Revised 14 Cases, with lines from Mid-C fully loaded and West interchanging from East.

[12] In Case #6 of the 14 Cases, the lines to DSW are fully loaded and East is interchanging from the West; it is not clear whether loss the interchange would result in more generation by East or reduced sales to DSW. Since GRID fully loaded the lines to DSW and East has unused capacity, increased generation at a cost less than the DSM price seems the more likely outcome. The same situation occurs for Cases #2, 6, and 12 in the Revised 14 Cases.

In the Revised 14 Cases, PacifiCorp introduced an alternative of pricing interchange at a fixed annual embedded value, which it set at $20/MWh. This value is higher than the market prices in many of the Revised 14 Cases. As a result, using that price would result in the buying control area paying more for interchange than it would pay for purchases from the market; integrated operation would become a burden rather than a benefit. PacifiCorp should look for other ways to incorporate actual costs into the pricing formula, such as by use of running costs.

To deal with the lack of realism discussed in the last three dot points, PacifiCorp should develop an interchange-pricing methodology that properly reflects transmission constraints and the costs each control area incurs or avoids due to the interchange.

2.2 Lack of Stand-Alone Dispatch

The failure to conduct a multiple step dispatch process which would help to identify whether the divisions are actually providing energy to one another, selling generation into the markets or buying energy from the markets is a problem common to all three interchange accounting proposals. The only information that PacifiCorp is proposing to use to conduct interchange accounting and to allocate system balancing based on its single dispatch process is the following:

- load in each control area,
- amount of energy produced by PacifiCorp units in each region, and
- the amount of market purchases and sales that are made to each external market.

Based on only this information, PacifiCorp is unable to determine how much of any of the external market purchases were actually made by any of the sides of the system, and how much energy either side of the system is generating to serve load on the other side of the system. PacifiCorp cannot know which resources each control area would run to serve the other or the market or avoid running due to interchange or system balancing. Therefore the proposals can not adequately capture cost-causation.

In contrast, a typical production-cost model with interchange-accounting logic would model PacifiCorp's dispatch in three steps:

- Perform an own load dispatch to determine what the cost to serve each area's load in the absence of any interchange.
- Conduct interchange on an internal system basis and account for the energy purchased and sold internally.
- Conduct interchange (which PacifiCorp calls system balancing) with the external market and account for the external market interchange.[13]

The results of dispatch would be available for each step and would identify the specific additional units both run and turned down due to internal interchange and system balancing. Unless PacifiCorp performs multiple production-costing runs with and without the

[13] Alternatively, the system balancing could be resolved prior to the internal interchange.

interchange with the external market, it will not have access to the information that could be used to identify that an external market purchase or sale is being made, for example, at the west market for the purpose of selling to the east. The incremental changes in dispatch from one run to the next would allow for the determination of the amount of energy each side purchases from (or sells to) each market.

PacifiCorp should develop a method for directly identifying the internal and external transactions and test its stability and administrative feasibility.

2.3 Long-Term Planning Asymmetry

Pricing Method 3 (and potentially some cases of the other methods) appears to create a problem of long-term planning asymmetry by rewarding a control area for being short. If its market prices are low, the short control area purchases from the market; if its market prices are higher than the cost of power from the long control area, the short control area obtains interchange from the long control area at a price lower than the cost of purchases from its own markets.

This problem can arise in Pricing Method 1, if the seller's price is lower than the buyer's market, and in Pricing Method 2, if the buyer is fully using transmission from its lowest-cost market and interchange gives it additional energy at the same price.

We are concerned about creating adverse incentives, especially if each possibility is not examined in detail. This problem requires two types of analysis. First, the MSP would need to determine the magnitude of the problem, by examining the potential for one control area to profit by leaning on the other area's capacity under various combinations of demand, supply and prices.

If the potential for free-riding is a matter of concern, the parties must develop a corrective adjustment to the Hybrid approach. This might involve requiring capacity-equalization payments from the area with a lower reserve margin to the area with higher reserves. The rules for capacity equalization would need to be developed, including

- The range of reserves over which equalization would be applied. The parties might, for example, agree that neither area would be required to pay capacity equalization so long as it maintains a 15% reserve margin;
- Whether non-baseload facilities would count in the equalization formula;
- Whether the formula should use capacity reserves or energy reserves (since it is, after all, intended to prevent abuse of energy interchange);
- Whether the rules would be applied prospectively or retrospectively based on actual values, or retrospectively based on normalized loads and dispatch.

Alternatively, an area that depends excessively on the other control area could be charged a surcharge for energy over a certain annual level. The parties would need to reach agreement on the threshold and the pricing formula. There may be other ways to discourage excessive inter-area energy dependence.

Solutions to this problem seem likely to erode the independence of supply outcomes in the two control areas, although the extent to which the system varies from PacifiCorp's proposal would depend on the magnitude of the problem and on the nature of the selected solution.

2.4 Resources Owned Across Divisions

The Hybrid approach and the three associated interchange accounting proposals assume that resources will be divided between divisions so that each resource is located in the control area it serves. This may not be the case and inclusion of cross-division assignment of resources may add additional complexity.

In the initial system split that PacifiCorp envisions, the East control area would wind up several hundred MW short of the average system reserve margin, and the former PP&L service territory in Wyoming would also be separated from the former PP&L generation in the West. In addition, the fuel mixes of the two control areas would be substantially different from system resources and from one another, increasing risk to both sides. The MSP parties are unlikely to agree to the proposed assignment of resources, and if the Hybrid approach were to be implemented, it would likely include some assignment of resources across control areas.

In addition, after the initial system split, both control areas may wish to participate in least-cost additions that are located on one side or the other. So even if the Hybrid approach did not start with cross-control-area resource assignments, such assignments are likely to arise. Indeed, preventing the control areas from sharing resources would preclude integrated least-cost planning.[14] So, the Hybrid approach must be able to account for resources located in one control area and assigned to the opposite control area for cost allocation and interchange purposes.

It is not clear whether PacifiCorp would propose to treat cross-division resource assignment with financial adjustments similar to those it proposes for exchanges, or a more realistic accounting for the effects of cross-division resource assignment on dispatch and transmission.[15] Either approach would add to the complication of the interchange process, and it is not obvious that either approach would be entirely satisfactory.

In a financial adjustment, energy from a resource would be included in the supply in the control area in which it is located, and that control area would provide a financial credit to the control area that bears the cost responsibility for the resource.[16] In this case, the credit and debit might include a provision for losses, which (in order to reflect the considerations in

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[14] This problem is in addition to the general tendency of the Hybrid approach to discourage integrated system-wide planning.

[15] The PacifiCorp Hybrid proposal deals with a somewhat related problem for a couple of exchanges that affect the divisions asymmetrically, where one control area provides the energy for the exchange and the other control area receives the return energy. In that case, PacifiCorp proposes to use a financial settlement to compensate the supplying control area, without considering whether transmission is available to move the returned energy from the receiving control area to the supplying control area.

[16] It is difficult to see how a financial adjustment could directly account for the effect of resource location on the effective transmission capacity between the control areas.

actual dispatch) would have to vary with the direction of load flow between control areas. If East is being supplied by a plant in the West and West is also interchanging energy from the East and/or buying energy from the eastern market (in Interchange Methods 1 and 2), East's assignment of the plant in the West decreases net flows and reduces losses. On the other hand, if West were interchanging energy to the East and/or selling energy to the eastern market, East's assignment of the plant in the West increases net flows and losses.

A more realistic approach would change the dispatch and adjustment of the initial position of each control area, adding the capacity of the resource to the position of the owning control area and subtracting it from the position of the control area in which the resource is located. This approach would also adjust inter-control-area transmission capacity, reducing it in the direction of the flow and increasing capacity in the opposite direction.

Either of these approaches would require that consensus be reached on several steps in the allocation process. If PacifiCorp is serious about pursuing the Hybrid approach, it should start to define a workable approach to cross-area assignment of resources.

2.5 Treatment of Direct Access

PacifiCorp has not presented a vision of how a state or portion thereof that has adopted direct access (such as potentially the Oregon industrial customers) would be treated under the Hybrid. Load that is transferred to direct access could be treated in several ways, each of which has different effects on the allocation methods. For example,

- The actual direct-access hourly load could be treated as part of PacifiCorp's dispatch, and the interchange computation could treat that load just like any other retail load. This raises some complications:
  - PacifiCorp has not explained how it would modify interchange accounting in its Hybrid model to accommodate the direct-access load and the freed-up generation. Some mechanism would almost certainly be needed for differentiating interchange between the regulated control areas from interchange with the direct-access load and generation.
  - PacifiCorp would probably sell the resources freed up by the departure of the direct-access load in the short- or long-term market. Since those resources are generally within (or connected to) the PacifiCorp service area, and could be purchased for the regulated load without using the transmission capacity from the market, the amount of power available for economy purchases would increase. The entities serving the direct-access load would become additional markets for surplus power from PacifiCorp's regulated load, in addition to the existing wholesale markets. These additional markets would need to be reflected in the system balancing and interchange computations. The pricing of transactions between regulated and unregulated PacifiCorp entities would need to be particularly carefully defined and monitored.
- PacifiCorp's dispatch could add a constant amount of load (constant over hours and/or years) as a proxy for the departed direct-access load. The problems would be similar to those identified in the preceding point.

- The direct-access hourly load could be removed from PacifiCorp's dispatch, along with some amount of generation. This approach would require that the interchange method be modified to reflect:
    - the change in interchange compared to the all-regulated condition,
    - the transmission freed up for the use of the remaining load,
    - opportunities for PacifiCorp to sell economy power to the marketers serving the direct-access load, which would increase the opportunity for off-system sales.
- The direct-access load could be treated as another control area, with assigned or allocated generation, sharing access to one or more markets and participating in interchange with the regulated control areas. This approach would create a number of complications, since all the questions under consideration for the control areas (assignment of resources, contracts, transmission, market access, interchange pricing) would also have to be addressed for the direct-access load. The assignment of sales contracts to the direct-access load may be particularly complex.[17] In addition, some of the transmission (to the other control area or the markets) could be used by either the regulated load in the control area, or the direct-access load, requiring additional steps in system balancing, as transmission not used by the regulated load is made available to the direct-access load and vice versa.
- The direct-access load could be treated as an external market, with its own market prices (determined by own-load dispatch and/or other markets) and with transmission interconnections with one or both regulated control areas. Any generation assigned or allocated to the direct-access load would be removed from PacifiCorp's resources. This approach would require assignment of resources and contracts to the direct-access market, determination (for each interface) of the amount of transmission that the direct-access market would remove from the regulated system, determination of the transmission capacity between the direct-access market and one or both of the control areas, and development of a methodology for setting the market price in the direct-access market.

There may be additional alternatives. Each of these options raises further questions of realism, equity, and administrative feasibility. And, the feasibility, details and implications of each of these options may vary with the details of the direct-access scheme implemented by a particular state. Since one motivation for the development of the Hybrid was to allow a state to pursue direct access without affecting other states, the failure to develop a mechanism for integrating interchange with direct access is a serious flaw in the current Hybrid proposal. Before the Hybrid could be treated seriously, the MSP would need to work

[17] If no sales contracts are assigned as the responsibility of the direct-access load, then the resources assigned to the direct-access load must be reduced to compensate for that load not taking its share of the off-system obligations with it. Since many of the wholesale contracts vary over the year, the identification of resources associated with the off-system sales is neither simple nor non-controversial.

out the interface of direct access with interchange accounting for a variety of direct-access rules.

2.6 Effect of PacifiCorp Management Decisions on Allocations

One feature of PacifiCorp's proposal for interchange accounting in the Hybrid approach is that PacifiCorp's management decisions could affect the inter-jurisdictional allocation of costs as well as the total level of net power costs.

For example, the interchange computations provided for the Boise meeting moved the delivery point for the SCE sale from Mid-C and COB to SP-15, served from East Main. In the earlier versions of the interchange model, the SCE load could be met with market purchases at the delivery hubs without using transmission; if that was not economic, the SCE load would use transmission and/or resources that—given PacifiCorp's interchange proposals—would otherwise have benefited primarily the Western control area. In the new contract configuration, PacifiCorp would either meet the SCE load with purchases at SP-15, or serve the load from East Main, using transmission and resources that would otherwise have been likely to have benefited the Eastern control area. Thus, the burden of serving the SCE load appears to have shifted from the West to the East.

In October, for Study #51, PacifiCorp was proposing to split the revenues from the SCE sale evenly between the control areas. PacifiCorp has not specified how it would reallocate the SCE revenues to reflect the new cost responsibility.

The example of the SCE sale raises the specter of PacifiCorp's routine contracting and other management responsibilities having asymmetric effects on the two control areas, favoring one and disadvantaging the other. It would be inequitable for PacifiCorp to increase costs for one set of states in order to reduce costs for another, and the states with the increased costs are unlikely to accept the shift. Faced with this resistance, PacifiCorp may be unable to renegotiate contracts in ways that would reduce total PacifiCorp costs, since the changes would affect interchange.

These complications do not arise under dynamic allocation. If moving the location of the SCE deliveries is beneficial for PacifiCorp as a whole, it is beneficial for every state.

PacifiCorp should explain how its interchange proposal can reflect the recent amendment of the SCE contract without shifting costs between jurisdictions, and it should propose a general and workable mechanism for cost allocation to allow cost-effective contracting to proceed without disadvantaging either control area.

2.7 Allocation of Transmission Costs

PacifiCorp's interchange-pricing methods do not treat consistently the allocation of transmission costs and benefits in two respects.

First, PacifiCorp has ignored the variable costs of non-firm transmission in the allocation of system balancing and the pricing of interchange. It seems obvious that the cost of moving power over non-firm transmission must be included in the valuation of those transfers. Otherwise, non-firm transmission used for one control area may be charged to the other.

Of the fourteen dispatch and pricing cases that PacifiCorp presented at the 2 April Boise meeting, PacifiCorp is purchasing non-firm power from DSW in Case #3, when East is interchanging to West, and in Cases #5 and 8, when East is taking power from West. In Case #7, the firm capacity from DSW is full, and any additional energy that East might need if not for the interchange from the West would be from East's own resources or the higher-priced non-firm transmission from the DSW.

PacifiCorp should develop methods for assigning or allocating non-firm transmission costs between control areas and for reflecting those costs in the pricing of interchange for each of its interchange and pricing methods. This method must deal with the treatment of the costs of non-firm transmission to and from external markets as well as the non-firm transmission between the Idaho bubble and East Main.

Second, PacifiCorp allocates the fixed costs of transmission to the external markets in a manner that is inconsistent with the differential access of the control areas to the various markets. All transmission costs are allocated on the basis of load, but PacifiCorp proposes to preferentially assign external market access to a particular control area (DSW to the East, and COB and Mid-C to the West).

In Interchange Method 3, each control area retains all the benefit of access to markets on its side. In Interchange Methods 1 and 2, each control area gets first claim to transactions with markets on its side, and retains most of the benefit of access to those markets. If PacifiCorp were to use any of these methods, the current practice of allocating transmission costs uniformly across control areas would not be sensible or equitable. Adding transmission to eastern markets would benefit primarily the Eastern control area, while adding transmission to western markets (even from the Eastern control area) would benefit primarily the Western control area.

For Method 3 to work properly, all the costs of the interties would need to be assigned to the control area to which they are assigned. For Methods 1 and 2, PacifiCorp would need to develop a basis for assigning intertie costs, reflecting the greater, but not total, dominance of each intertie by the nearer control area. Alternatively, as suggested in §2.1.1 above, PacifiCorp could allow both control areas equal access to all markets and allocate transmission costs equally across load in the control areas.

3 MODELING AND DATA ISSUES

The discussion above reveals problems that lead to inequity in the treatment of the two control areas. These identified problems may all be solvable, although the solutions are likely to increase the complexity of the method and may conflict with other goals of the MSP participants. Where possible, we have offered solutions and indicated the possible tradeoffs. However, we are well aware that many bright and talented people worked hard to develop interchange accounting methods that would be fair and acceptable to all parties. That these methods could be flawed in the manner set out above reminds us of the great challenge any new and significant change in approach creates. Unexpected outcomes are a given that are only ironed out with much experience. If some manner of interchange accounting were initiated, we would expect that many more such flaws would be revealed requiring redress of varying magnitudes and complication.

An equally if not more concerning aspect of the Hybrid approach as a method of cost allocation relates to the source and modeling of hourly prices for allocating costs by jurisdiction. While traditional cost allocation methods first estimate *annual* net power cost and then apply well understood and stable allocation factors to the annual total to determine each jurisdictions annual share, the Hybrid approach estimates and allocates cost in each hour. These hourly costs are then summed to determine each jurisdictions annual share of the total. Significantly, the hourly data and hourly modeling is fraught with error.

3.1 Data for implementing the Proposed Interchange Accounting Methods

The proposals for the treatment of interchange energy base the pricing, at least in part, upon hourly market prices at particular delivery points in the western markets—specifically hourly market prices for COB, Mid Columbia, and DSW. We are concerned that the Hybrid approach to inter-jurisdictional cost allocation is particularly sensitive to the results of hourly market price assumptions and to the details of the GRID model representation of the PacifiCorp system. The resulting rates may be unacceptably volatile fictions.

3.1.1 Source and Validity of Hourly Price Data

GRID requires an hourly price for each of its nine bubbles. At the April 29 presentation to Utah parties on Version 2 of GRID, PacifiCorp representatives indicated that they would use data provided to them by their Commercial and Trading arm. Since many of these bubbles are illiquid with no trades taking place in many hours, C&T would provide the hourly prices they believe they could have bought or sold for in those hours had there been an operating market.

While indicative pricing may be the best information available and may be tolerable for determining annual net power cost, using such fictional estimates for allocating costs between control areas is less defensible. And outside verification of PacifiCorp's indicative pricing is not possible.

Specifically, it appears that there is no source of acceptable hourly market price data for COB, Mid C, and DSW – actual or projected. In response to Data Request 3.1, PacifiCorp identified two data services for hourly prices in the Western electricity markets: Powerdex and Dow Jones. We have contacted both Companies. Their representatives were friendly and informative. From those interviews, the problems with the use of the hourly price data in hourly interchange pricing for the PacifiCorp system became clear:

- Just as in PacifiCorp's hourly price data, there are significant gaps in the reported data for actual transactions, and "indicative prices" are inserted to fill those gaps.
- The market data services cannot provide information on the number of trades or the concentration of the market.
- For one of the services, hourly prices are not entirely for hourly transactions. That is, many or most of the transactions span multiple hours – so when the average price for a particular hour is calculated it includes transactions for various longer time periods. For example, a reported price of $40/MWh for the hour ending 10 am, might be the average of two transactions: a one hour sale at a price of $30/MWh, and an eight hour sale (say for the hour ending 10 through the hour ending 17) at a price of $50/MWh. For this

reason, observed shape of prices over the course of a day can be the result of idiosyncrasies in the types of transactions and volumes during the day.[18]

- Auditing the data by state agencies or their representatives would not be possible, since the confidentiality of the data sources is maintained.

The last point is particularly important for the use of a model in a regulatory context. Data from market services are relied upon for various regulatory purposes (e.g., asset valuation and power-cost estimation for rate making). However, to rely upon hourly price data for interchange energy accounting would be unwise. The hourly price data depend upon subjective judgments on the part of the data service provider and upon sources with an incentive to misreport certain information.

Projecting *hourly* market prices for use in interchange accounting for planning and ratesetting is even more problematic, and it would be generally advisable to avoid reliance upon forecasts of hourly prices when possible.[19] The interchange accounting logic under consideration for PacifiCorp would depend not only upon projected hourly market prices at one location, but upon the projected hourly market prices at several locations (COB, Mid-C, and DSW) and upon the relationships forecasted between those prices. That is, the *relative* volatility and price levels at those locations will drive the Hybrid model. For example, if high prices in the East occur when prices are also high in the West, then the result will be very different than if the high prices in the East tend to occur at the same times as low prices in the West. We have not reviewed the Company's method of projecting hourly prices, but we expect that the shaping approach and the Midas model are not adequate to reliably and reviewably project relative hourly market prices in the various Western markets.[20]

The situation is different, but no less problematic, for the normalized historical test year used in Utah ratemaking. The historical test year may reflect low water, high gas costs, or major PacifiCorp plant outages, all of which would increase the historical net power costs (or conversely, high water, low gas cost, and few plant outages, all of which would decrease prices), and all of which are normalized in the ratemaking net-power-cost computation. But the market prices, which are driven by the same factors as the net power costs, would

[18] In the example above, the reported price for hour 11 might be the $50 from the eight-hour sale, the price for hour 12 might be $45 (averaging the 8-hour sale with a $40 hourly transaction), hour 13 might be $60 (averaging the 8-hour sale with a $70 hourly transaction), and hour 14 might be back down to the $50 from the eight-hour sale. Much of the variation in prices would be an artifact of the timing of transactions, rather than a reflection of market price in the hour, and none of the reported prices would be the actual hourly market prices ($30/MWh for hour 10, $40 for hour 12, and $70 for hour 13).

[19] Projections of *annual* market prices are generally subject to considerable uncertainty and error but are accepted for planning purposes. Indeed, since certain decisions must be made that depend in part upon future market prices, there is no practical alternative to relying upon annual market price projections. Techniques such as scenario analysis, sensitivity analysis, and various sorts of risk analysis are developed to provide insight into the impacts of deviations of projections from actuals for long-run decision making.

[20] Utah does not use projected market prices in rate cases, so this problem does not directly affect Utah. But it may adversely affect the durability of any Hybrid approach developed by the MSP, which should be of concern to all parties.

apparently not be normalized in PacifiCorp's proposed Hybrid approach.[21] This could result in a serious mismatch between the conditions assumed on PacifiCorp's own system (which would always be normalized) and conditions in the surrounding markets, which could include prices much higher or lower than normal and could result in very unusual system balancing and interchange flows and prices. For example, after a cold winter with low water, PacifiCorp might file a Utah rate case that showed high COB and Mid-C power prices, large sales from PacifiCorp to those markets (since the model would treat PacifiCorp as having better water conditions and milder weather than the rest of the region), and high prices for interchange (which would be largely driven by those Mid-C and COB prices). Those conditions might be unlikely for any consistent combination of weather and fuel prices, and could have important implications for the operation of interchange in the Hybrid model.

If there were no alternative to relying upon hourly market prices, then it would be necessary to make every reasonable effort to improve the data sources and models so that the result would be as reliable as possible. Since this would involve considerable effort without assurance of a reasonable outcome, it is fortunate that there are other alternatives available for allocating power costs among the PacifiCorp states.

3.1.2 Sensitivity of Interchange Accounting Methods to Hourly Price Data

Hourly electricity market prices can be quite volatile, with spikes where individual hourly prices are an order of magnitude or more higher than the average price. Power-cost results for an electric utility system can be somewhat sensitive to the market prices in a small number of hours. This is a fact of life both for actual power costs in today's electricity markets and for computer model simulations of those power costs.

Under traditional cost allocation methods, these somewhat sensitive estimates of total system power cost will be allocated to jurisdictions using relatively stable and relatively well-understood allocation factors. With the Hybrid approach, the vagaries of the hourly market price projections will play an important role in the allocation of energy costs to jurisdictions. This introduces a second opportunity for hourly energy market prices to introduce volatility and instability into the cost figures for individual jurisdictions. Not only will Western market prices play a role in determining the "size of the pie" they will impact a jurisdiction's "slice of the pie."[22]

Under the Hybrid approach, estimates of market prices can have much larger effects on the slicing of the pie (the allocation of costs) than on the size of the pie (the estimate of total PacifiCorp interchange costs and revenues). The attached example provides five sets of market prices (for four periods and three markets) that produce the same net system

[21] If the market prices were to be normalized, the problem in Utah would be even worse than the problem for the states with future test years, since no transactions or quotes would be available for the hypothetical normalized year.

[22] Allocating energy costs on an hourly or monthly basis would also result in market prices affecting each jurisdiction's allocation, but that effect would be much smaller than pricing hourly interchange at market prices.

balancing revenues ($30 million) but widely different net interchange valuations between the West and the East, ranging from $29 million to $72 million.[23]

Consider a particular hour with a very high hourly market price. If a control area happens to be "buying" (i.e., generating less than its demand in the PacifiCorp centrally optimized dispatch, so that it is deemed "short" in that hour) then that control area may find itself with a large cost associated with that hour. If some aspect of the modeling (e.g., timing of maintenance outages or the representation of hydroelectric generation over the hours) were responsible for this situation, then the large cost allocated to the "short" jurisdiction might be inappropriate. Some examples of how this problem might occur:

- The optimal integrated dispatch in a particular hour might involve very low hydro dispatch, as hydro resources are reserved to meet load in other hours. But the Western division might have a relatively high load at that hour, offset by low loads in the East. When the West's load is compared to the generation from the plants assigned to that division, the West would be short and would be treated as receiving interchange from the East. The decision not to dispatch hydro in that hour was based on the availability of $10/MWh coal-fired energy from the East; if interchange were priced at market, the West might pay for that coal at $40/MWh or more.[24] This would be true even if all the transmission to the external markets were full.
- There may be high-load hours for the East in which large amounts of hydro are dispatched. The East's load could be met with gas-fired units, but that output is sold into the market. When the divisional loads are compared to the output of the generation assigned to them, the East would appear to be short on generation, and would be allocated Western energy at market prices. So even if East could have generated its own power at $20/MWh, it may be charged the market price of $40/MWh or more.
- The scheduling of maintenance for the integrated system may result in one division or the other being consistently short on capacity throughout a month or more. For example, a major outage scheduled at Bridger could leave the West short in many hours. In the integrated system, this might well not be a problem at all, since other plants with similar energy costs would be available. But the interchange computation would show large amounts of interchange from the East to the West, and the West would be charged for the deficit at market prices.

Any computer model simulation used for production costing is subject to uncertainty, and changes in particular input assumptions will influence the results. However, our concern is

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[23] In this example, the system balancing purchases are assumed to be evenly distributed between the two markets with the lowest prices in the period, and sales are evenly distributed between the two markets with the highest prices in the period. For ease of computation, the year is divided into four equal time periods.

[24] If the West were a separate company making dispatch decision, and it faced a market price of $40/MWh for purchases from the East, then the West might well have dispatched the hydro resources (or at least gas) in that hour instead of purchasing from the East. This example illustrates the problems that can arise when dispatch decisions and interchange accounting are based on different costs. Also, in this situation, the transmission interface to the high-priced market would probably be fully loaded, so this example also illustrates the problems caused by using unavailable markets for pricing interchange.

that the GRID model outfitted with an interchange accounting method will be particularly prone to producing cost results for individual jurisdictions that might be sensitive to particular input assumptions. For example, inaccuracies or changes in key inputs such as the hourly market price forecast for the Western trading hubs, the hourly shape of hydro generation, or the representation of the exchange contracts could have a significant impact upon the results.

3.2 Under and Over Collection of Costs

The sensitivity of the allocations to estimates of hourly market prices may also introduce inconsistencies between rate-case filings in various jurisdictions leading to under-collection or over-collection of interchanged energy costs.

For example, a production-cost run used in one state in June 2004 may indicate that the East will be obtaining interchange energy from the West at high-cost hours and returning it at low-cost hours in 2005. A run performed in December 2004 for another state may indicate the exact opposite, while a run performed in early 2006 based on a 2005 historical test year for Utah may produce a different result still. Depending on which jurisdiction each of those filings happens to occur, PacifiCorp may under-collect or over-collect for interchanged energy.

Whether revenue requirements are computed for a forecast test year or a normalized historical test year, the allocations under the Hybrid model would depend on the details of the modeling of the hourly market prices. The regulators and participants in rate cases would need to understand exactly how each hour’s market prices were set; the basis for changes since the last rate case (including rate cases in other jurisdictions); and PacifiCorp’s underlying assumptions regarding the relationships between market prices and time of day, season, PacifiCorp loads, maintenance schedules, and fuel prices. Rate-case participants could be expected to dispute PacifiCorp’s modeling assumptions unfavorable to the state involved and (where relevant) to individual rate classes. These disputes, the added complexity and costs of rate cases, and the likelihood that states will adopt inconsistent assumptions regarding market price patterns may undermine the durability and sustainability of the Hybrid method.

3.3 Grid Model Methods

We discussed the unavailability of useful hourly market price data previously. Here we shift to four related modeling issues:

- The magnitude of error in the backcast of system balancing sales and purchases.
- The problems of assuring consistency of the market-price inputs with the other inputs to the GRID model.
- GRID’s failure to reflect the effect of water conditions on market prices.
- GRID’s deterministic representation of forced outages.

3.3.1 GRID Benchmarking Results

While apparently adequate as a net-power-cost tool for a traditional ratecase, GRID's estimation of system balancing raises serious concerns for the Hybrid approach to cost allocation.[25] PacifiCorp's GRID team presented an update of Version 2.0 of GRID and the most recent benchmarking of the power cost tool to interested Utah parties Tuesday April 28, 2003. The benchmarking covered the historical period October 2001 through September 2002.

In the benchmarking runs, all of the input values (prices, short-term transactions, and outages) were set at historical values. GRID was asked only to determine system-balancing purchases and sales and the dispatch of thermal resources and long-term contracts. The following table summarizes the deviation of the GRID run from actual, as a percent of the actual value.

	Energy (MWh)	Total Value ($)	Average Value ($/MWh)
Net Power Requirements	0.0%	-0.1%	-0.1%
Thermal Generation	-1.0%	-0.1%	0.9%
System-Balancing Sales	-37.5%	-44.2%	-10.8%
System-Balancing Purchases	-26.3%	-38.1%	-16.1%

The model output that matters for current rate cases, annual Net Power Requirements, is very close to actual values. The modeled value of annual Net Power Cost deviates from actuals by approximately 0.1%. However the model output critical for determining each state's share of system costs under the Hybrid approach (the amount and value of the system-balancing transactions, and the market prices) does not closely represent actual values even averaged over the course of the year. The GRID run understated the energy associated with actual system-balancing sales by 37.5% and purchases by 26.3%. In addition, the GRID run understated actual system-balancing sale revenues by 44.2% and purchase costs by 38.1%. Given that these are annual figures, and are thus an average over the hours in the year, the errors are likely to be much larger in many hours. Yet the hourly results are the basis of the interchange accounting methods, methods upon which the Hybrid approach depends.

The discrepancies between modeled and actual transactions may mean that GRID estimated, for example, that East was interchanging power from the West in many more (or many fewer) high-priced hours than actually occurred, or that West was interchanging from

[25] The Committee has not yet evaluated or approved GRID as a rate-case tool. We are simply making the distinction between the use of GRID as a traditional rate case power cost tool versus the use of GRID to produce outcomes that become the basis for interchange accounting.

the East in many low-cost hours, or that any other combination of non-existent transactions was occurring and real transactions were not occurring.

At this point, PacifiCorp clearly does not have a production-costing model adequate for supporting the Hybrid model of jurisdictional allocation in ratemaking. Perhaps PacifiCorp can still fix GRID so that it reliably reproduces reality. Or perhaps PacifiCorp will decide to replace GRID with a multi-area production-costing model such as PROSYM or PROMOD.

Some aspects of system balancing may be beyond the capabilities of any production-costing model to accurately reproduce. Such models (including GRID) optimize the system's transactions and resources in a given hour based on perfect knowledge of the future. In practice, to balance the system in a given hour in the presence of uncertainty, the Company may be participating in multiple transactions in various forward, day-ahead market and same-day markets.[26] Thus GRID will tend to understate total market transactions. While GRID's characterization of hourly operations may produce reasonable annual results, the basis of the current sharing among states of Net Power Costs, it remains to be determined whether or not GRID produces reasonable hourly results, the basis of sharing, and most importantly the pricing and quantification of interchange, among the states under the Hybrid alternative.

It is not clear that PacifiCorp can eliminate these major discrepancies without making a series of manual adjustments that cannot be reproduced in the normalized and forecasted runs used in rate cases. The backcasting exercise also suggests the level of care that each jurisdiction would need to take in reviewing PacifiCorp's claimed net power costs in each rate case under the Hybrid approach. Regulators would need to check the reasonableness of PacifiCorp's modeling in great detail, examining the timing, magnitude, and pricing of each hour's interchange, which would require review of the modeling of hourly market prices. This level of detail may not be administratively feasible.

At the very least, a lot of work (including repeating work done with the current GRID model) remains before PacifiCorp could implement the Hybrid method. It is also possible that system balancing cannot be modeled at the level of accuracy necessary to support the Hybrid proposal.

3.3.2 Consistency of Grid Inputs

As we understand the situation, the market price inputs to GRID have been (and would continue to be) derived from two sources, neither of which is necessarily consistent with the fuel prices, loads, resource additions and other assumptions in GRID. For the first few years, PacifiCorp develops hourly market-price projections for COB, Mid C, and DSW from broker's quotes provided by its Commercial and Trading arm for forward electricity contracts. PacifiCorp has not discussed how it will ensure that the fuel-price inputs for GRID are consistent with the broker's expectations.[27] Nor have we seen an explanation of how

[26] The backcast forced short-term transactions to equal actual values. In rate-case applications, this matching may not be possible or appropriate, so the GRID results for system balancing and interchange may very sensitive to the assumptions about other short-term transactions.

[27] Perhaps the GRID gas-price inputs could be driven by forward gas contracts from a sample of brokers similar to that supplying the electric forwards.

PacifiCorp plans to convert forward price quotes by period (peak and off-peak) and season (or perhaps month in the short term) into hourly market prices.

These short-term forecasts are the important ones for rate cases in jurisdictions with future test years. In order to validate the interchange required by the Hybrid model, PacifiCorp must be able to demonstrate that it can produce forecasts of hourly market prices that are consistent with the GRID inputs and that have reasonable patterns over daily, weekly and seasonal cycles, including the appropriate variation and appropriate co-variance with PacifiCorp's costs.

A somewhat different problem arises for the normalized historical test year of a Utah rate case. Power costs in Utah are determined using normalized forced and scheduled outages, fuel prices, and loads to reflect average weather. Long-term firm sales and purchases are annualized for contract changes. Actual prices are generally used for short-term firm and nonfirm sales and purchases. However, as discussed above only spotty actual hourly price data will be available for the test year. And broker's quotes will not be consistent with the normalized test year, unless the normalized fuel prices, normalized plant availability and normalized loads are identical to those expected in the market prior to the test year.[28] Therefore, consistent and reliable data will not be available for conducting a Utah rate case.

For longer-term forecasts, PacifiCorp develops hourly market-price projections using the MIDAS model. It is not clear that GRID and MIDAS produce equivalent results from the same inputs; if they did, PacifiCorp would not have needed to develop GRID. Further, PacifiCorp's use of long-outdated market prices in the GRID runs for most of the MSP raises questions about PacifiCorp's ability to update the MIDAS runs on a timely basis.

PacifiCorp has additional work to do in establishing that the market-price inputs to GRID, can be kept up to date and internally consistent with the other GRID inputs, while still allowing for review of the market-price derivation in the course of a rate case.

3.3.3 Water Conditions and Market Prices

The GRID model is run for a set of "50 water years" reflecting a range of output from PacifiCorp's hydroelectric plants and contracts, and the production-costing runs are averaged across water years to produce costs and dispatch results for each calendar year. In the Hybrid model, those dispatch results are then used to determine interchange and allocate system balancing between the control areas. As we understand PacifiCorp's use of GRID, the same market prices are assumed for all water years. In reality, a bad water year for PacifiCorp's hydro generation is likely to correspond to a bad water year for the Northwest (and perhaps California as well), so that the years in which the Western control area is buying (or interchanging from the East) the most energy will also tend to be the years with the highest market prices, particularly at COB and Mid-C. In the good water years,

[28] Demonstrating that broker's quotes incorporated the conditions of the normalized test year will be difficult, at best. In most cases, the normalized test year will be different from broker's expectations, since the brokers would have been reflecting the actual water situation, projected weather patterns and fuel costs, rather than normalized values.

when the West would be selling into the market and interchanging to the East, market prices are likely to be low. We believe that, for each water year:

- market prices for COB, Mid-C, and DSW should be projected consistent with regional supply and demand conditions,
- GRID (or some more sophisticated production-costing model) should be run for the combination of hydro energy and market prices, and
- the Hybrid system balancing and interchange should be conducted for the resulting dispatch.

The multiple results for the various water years can then be averaged. This more realistic if more complicated computation is likely to yield significantly higher expected values of dollar interchange from East to West (or lower West to East) than PacifiCorp's current approach.

3.3.4 Effect of Deterministic Representation of Forced Outages on Hybrid Approach

GRID is a linear-programming model that represents generating unit forced outages as a constant deterministic derating of capacity.[29] While this simplification will produce a reasonable projection of the amount of generation from baseload units, it is not likely to produce a reasonable projection of the annual or hourly operation of other resources—combustion turbines, Gadsby steam, combined-cycle duct firing, and various purchases—and especially not the system balancing and hourly interchange between control areas. The amounts, direction and costs of system balancing and interchange are driven by the operation of the integrated system under a wide range of conditions, including the high-load and high-outage hours when peaking generation might be operating. Errors in hourly modeling have little effect on allocations from the Dynamic model.[30] But errors in the volumes, direction and pricing of the imputed interchange between control areas in the Hybrid model may be significant.

As an example of the lack of realism in the GRID treatment of outages, consider the situation in which PacifiCorp has

- a peak load of 8,000 MW,
- 9,200 MW of resources (an installed reserve of 15% or 1,200 MW),
- shoulder months with loads low enough that all maintenance can be scheduled off-peak, leaving at least 1,200 MW of reserve after maintenance all months,
- and a 10% forced outage rate, which GRID would model as a 10% (800 MW) reduction in resources in every hour,

[29] See, for example, (a) the description for "attribute" called "derate factor" in the "GRID Attribute Guide" or (b) the GRID "User Documentation: GRID Algorithm Manual".

[30] Even the use of hourly energy prices would not make the Dynamic model very sensitive to system balancing or the flow of energy within the system, since any error would affect only the small percentage of energy purchased in the markets (and generally only a part of that).

In these circumstances, GRID would never dispatch for PacifiCorp's own load the 5% (400 MW) of generation with the highest variable costs. In the real world, with stochastic outages, PacifiCorp sometimes has 200 MW of forced outages and sometimes 1,400 MW, so all of its resources are dispatched at some times (and power is purchased to cover any additional shortfalls). The GRID modeling of outages tends to understate the use of peaking resources, and the energy-interchange value of those units to the division to which they are assigned.

The error with the "derating" method results from the smoothing of the forced outages, which avoids the multiple simultaneous outages of baseload generator that can cause PacifiCorp to operate high-cost resources. Models that employ a probabilistic representation of forced outages (e.g., MULTISYM, PROMOD) will recognize that multiple outages occur on a statistical basis, and will tend to show high-cost energy resources running more often than they do in a model with deterministic capacity deratings.