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Memorandum

To: Public Service Commission

From: Division of Public Utilities
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Date: June 21, 2004

Subject: US Magnesium Interruption 2003 Report established under Docket No. 01-035-38 *In the Matter of the Application of PacifiCorp, dba Utah Power & Light for Approval of Provisions for the Supply of Electric Service to Magnesium Corporation of America*

I. ISSUE

The Commission's Order in this docket, issued May 24, 2002, required that the Division provide annual reporting on the interruption of US Magnesium (USM). Specifically, the Division was ordered to "monitor and analyze the operational performance of the interruptible service provided to [US Mag] and provide an annual report to the Commission…."[1] The Commission order also stated that the report should include "information comparing results of operation with anticipated benefits and recommendations on appropriate terms and conditions of service as analyzed experience with this interruptible load is gained."[2]

The first report issued December 11, 2002, reviewed the 2002-interruption period. The following review evaluating the 2003 interruption period is provided in compliance with the Commission order. It is based on information received from both PacifiCorp and USM.[3]

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[1] May 24th Order, page 14.
[2] Ibid, Page 14.
[3] Two sets of data requests were submitted to PacifiCorp. Responses to the first set were submitted

The DPU regrets the delay in the filing of this report. However, responses to DPU's first data request were not as complete as required to prepare this report, thus necessitating a second set of requests. Responses to the data requests were also not received in as timely a manner as needed. By the time responses were received DPU's attention was on numerous other dockets, including MSP (Docket 02-035-04) Currant Creek (Docket 03-035-29), and numerous Avoided Cost dockets. Additionally, the DPU sent drafts of this report to both USM and PacifiCorp to provide them an opportunity to identify if there were corrections or questions about the data presented or if these parties had other differences that they wished to communicate. This final memo attempts to address the responses we received.

II. OVERVIEW 2003 INTERRUPTION

During 2003 USM was subject to interruption for the months of June-September inclusively for up to six hours a day (1:00-9:00 PM) five days a week (Monday-Friday). PacifiCorp called on USM each day of the interruption period. As in the previous year (2002 interruption period), USM had the option to respond to the notification stating whether or not it would physically interrupt or buy-through; no response from USM indicated an intention to buy-through. USM bought through on all days of the interruption period, except two during which it physically shutdown part of its operation.

On each day of interruption USM assessed its buy-through option based on the buy-through price it would be charged. The price charged is based on the market price shaped for the hour of the buy-through. Specifically, USM pays a Palo Verde market price adjusted by hourly shaping factors for each hour during the interruption period for which it chooses to buy-through. USM indicated that if the adjusted market price it would pay for the buy-through power resulted in its variable cost of production exceeding the market price it receives for the sale of its products, it would not exercise the buy-through option for at least part of its load. USM has calculated that it would likely buy through if the market price were above $80 or so.

For one of the two days it chose physical interruption, June 3rd, USM assessed that the adjusted market price for power would likely be above an economically attractive level . Thus, it chose to shutdown a portion of its operation to drop its load. On June 5th, although prices were lower than June 3rd, USM did again physically curtail a portion of its load. The fax transmittal for that day indicated that the purpose of the interruption was a "Trial to see long term cell performance reduction."

On these days, USM responded to the "Curtailment Notice" it received from

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October 24, 2003 and received December 18, 2003. The second set was submitted January 21, 2003 and responses were received February 16, 2003. In addition, information was also garnered through Interruptible Task Force discussions and other informal data requests.

PacifiCorp via fax. USM identified an estimate of the amount it would physically curtail and the amount of replacement power it would need. On June 3 and June 5, USM indicated it would buy-through 60 MW and physically reduce its load by 25 MW. Its estimate was based on the amount of power it required to maintain operation for half of its magnesium cells during the interruption period. However, a cell cannot be offline for the full six hours of interruption. Thus, for three hours, USM let one-half of its magnesium cells be offline and then brought them back up and dropped off the other half of the cells for the remaining three hours of the interruption period.

The actual level of interruption for June 3rd and June 5th was based on the physical load reduction on those two days. Attachment A to this memo contains the load reduction, power purchased and market prices for June 3-5. The data indicates USM did curtail about a third of its load during the interruption period on both June 3 and 5.

In all other hours of the interruption period, USM elected to buy through. Its total buy-through energy was 42,807 MWh. For its buy through power in the months of June-September, USM paid an average price of $63.15/MWH.[4] The total paid by USM for replacement power was $2,705,692.[5] Its firm energy usage during the months of June through September, inclusively, was 180,524 MWh resulting in an average summer price of $29.09/MWH (based on a 21-mill rate in all hours other than the buy through period). USM's total firm energy in all other months was 392,047 MWh, which was billed at the contract price of 21 mills. Combining these results, the average price paid by USM for power in 2003 was $23.94/MWH.

Based on its review of the manner in which interruption took place and the pricing of USM replacement power, the Division believes that the 2003 interruption of the USM load was done in accordance with the terms of the Commission order in this docket.

III. ANALYSIS

Revenue Requirement Impact

In its Order on Petitions for Reconsideration in this docket dated July 2, 2002, the Commission ordered *situs* treatment of the USM contract due to the experimental nature of the terms of service and to avoid "attendant uncertainty."[6] Additionally, the Commission noted that the issue of special contract treatment was an unresolved issue pending in other proceedings. For situs assignment, both the costs and revenues

[4] This is the average shaped market price. The average price market price minus the shaping factors was $53.91/MWH.
[5] The average costs of this replacement power based on the unshaped average market price was $2,307,560, resulting in an addition of approximately $398,131 (i.e., as a result of the shaping).
[6] Docket 01-035-38, Order on Petitions for Reconsideration, July 2, 2002, page 2.

associated with serving the USM load are allocated to Utah. However, the costs of the load served during the buy through period should not be assigned as part of the revenue requirement; rather, this is a cost directly paid by USM for purchasing replacement power during the curtailment period. The power used during this period is assumed to come from the market and not from the PacifiCorp system *per se*. In short, Utah's revenue requirement should reflect only the cost of service imposed by USM on the PacifiCorp system. Additionally, the inter-jurisdictional allocation should reflect a reduction in Utah's contribution to the system coincident peak, to the extent that the USM interruption results in this offset.

In the recent rate case docket (Docket No. 03-2035-02), PacifiCorp adjusted the Revenue Requirement filing to remove USM from loads associated with the buy through during the economic curtailment period. The removal of the costs and revenues during the buy through should result in the Revenue Requirement reflecting only the cost of service associated with the PacifiCorp system and should also lead to a full assignment of the benefits associated with the USM interruption. The benefits can be defined on the basis of a lower revenue requirement to Utah because the costs (load) during the buy through are not assigned. Moreover, if the buy through results in USM not utilizing system resources during the time of system coincident peak (CP), Utah contribution to the system CP is reduced leading to a lower revenue requirement assignment.

There are two adjustments required so that the benefits of the USM interruption are captured in the Revenue Requirement that is ultimately assigned to Utah ratepayers: (1) Adjustment to Net Power Costs (NPC) and (2) an adjustments to Utah's load to account for the interruption. The net power cost (NPC) must be adjusted to remove the costs of the buy through that is directly paid for by USM. Essentially, it is necessary to eliminate from the revenue requirement the impact of the buy through service provided to USM; i.e., the revenue requirement must be adjusted so that other ratepayers are not allocated the costs of the buy through.

It is in the GRID model used to calculate net power costs (NPC) that the costs of the buy through must be removed to prevent these costs from being allocated to other ratepayers. Effectively, this lowers system NPC and, thus, Utah's allocation of NPC. To do so, PacifiCorp assumed that the costs were equal to the amount that USM paid to purchase power during the buy through, or $1,348,920.[7] This amount was removed from the NPC and Utah was allocated its load-based share (39.4031%) of the reduced net power costs. The impact of this was to lower Utah's revenue requirement associated with NPC by $531,516 for the test period.

Once costs and revenues of the buy through are identified, the revenue requirement model should properly incorporate the fact that these costs and revenues are

[7] The buy through is assumed to represent the incremental power cost that is not incurred because USM is "economically curtailed" and bears the costs of purchased power during the interruption period.

directly borne/paid by USM. PacifiCorp identified two possible methods for adjusting the Utah revenue requirement so that the benefits and costs of the contract are correctly assigned. The first method would be to directly assign revenues and costs of the buy through period to USM. Since the net effect of this should be zero (costs should equal revenues by assumption), removal of both the revenue and costs associated with the buy through period should also suffice. In its Revenue Requirement filing in the recent rate case in Utah (Docket No. 02-2035-3), the revenues and costs associated with USM's buy through for economic curtailment periods were excluded.[8] This method was chosen because it resulted in more consistent application to the Cost of Service model.[9] This is discussed further below in the section "Cost of Service Analysis."

The NPC adjustment only captures a portion of the benefits that result from the USM interruption. The second adjustment, a change to Utah allocation factors, must be made to account for the notion that USM is not served by PacifiCorp resource directly during the buy through period. Thus, it is assumed that the USM loads are not "stressing" the system during this period, or effectively do not occur over the interruption period.

For the Utah Revenue Requirement filed in docket 03-2035-02 it was assumed that USM was not served during the interruption period. During the test period used to calculate revenue requirement in this docket, USM was subject to interruption in the months of July and August. However, during the rate effective period resulting from the rate case, USM would be subject to four months of interruption. To account for the fact that USM was subject to four months on interruption, June-September, in 2003 and would be again in 2004, PacifiCorp removed from Utah loads USM's contribution to test period system peak and energy consumption during those four months. The result was reduction in Utah's revenue requirement of $2,404,057 associated with the reduction in allocation factors.

Based on Division review of the treatment of the USM costs in the most recent rate case in Utah, docket 03-2035-02 and subsequent data request related to this issue, the Division believes that the treatment of the USM contract was consistent with the July 2002 Order. However, it should be noted that USM's actual interruption in 2003 exceeded the interruption in the 2002 test period relied on in docket 03-2035-02. Thus, the reduction to NPC is understated based on the method used by the Company. The actual buy through costs for 2003 were $2,705,692. Assuming the same allocation factors used for the test period, this would have resulted in a reduction of $1,066,126

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[8] It is worth noting that this adjustment was incorrectly done in the Initial Revenue requirement filing in this docket, resulting in an overstatement of the benefits to Utah ratepayers of the economic curtailment. Essentially, the costs were removed from the NPC and then a second adjustment was made to remove the USM costs form the buy through. Revenues were then directly assigned to Utah and the costs removed twice. However, PacifiCorp filed a Revised Revenue Requirement that was corrected for this error.

[9] When revenues and costs were directly assigned it tended to overstate the unit cost of service to USM.

($2,705,692*39.4031%) in the NPC portion of Utah's revenue requirement.

In sum, the benefit from the USM interruption using test period assumptions was $2,939,573. If NPC alone is adjusted to account for the higher value of USM purchased power during 2003, the revenue requirement reduction would have been $3,470,183.

Cost of Service Analysis

In this section, we discuss the method employed by PacifiCorp to evaluate USM's load in the Cost of Service (COS) model in the most recent rate case. This discussion is based on PacifiCorp responses to Division data requests and also the Division staff's review of the COS model.

In docket 03-2035-02, the original COS study filed by PacifiCorp overstated the cost of service to USM. This occurred under the method of direct assigning both the revenues and costs of the buy-through to USM. This treatment did not impact the revenue allocation or the allocation of costs but it did overstate the number of kWh of firm service to USM (i.e., recall the "buy-through" power is not assumed to be served by PacifiCorp per se). To correct this, PacifiCorp adopted the method of simply removing both the costs and revenues of the buy-through.[10]

The corrected March 2003 COS study shows that the average price paid by USM was 21 mills based on the terms of the USM contract for firm power.[11] The COS shows that the cost to serve USM was $13,802,367 before the rate increase and based on usage of 498,097 MWH. The revenues received from USM were $10,286,324. The difference between firm revenues and costs of service before the rate increase was $3, 516,043 based on the filed COS. This indicates that the firm COS rate required to cover costs was 28 mills prior to the rate increase. Firm rates are for the service provided outside the interruption period. Thus, this is not a firm rate as would apply under the assumption of 12 months of full firm service. The summary section below further addresses this.

After the COS is adjusted for the $65 million rate increase, the cost of service to USM increase to $14,569,628, for a difference from revenues of $4,283,304 and an average COS rate of 29.25 mills.

However, because Utah's revenue requirement is reduced by $2,939,573 (as estimated by PacifiCorp), the firm COS could be adjusted to reflect this reduction in cost to Utah. The result is a firm COS after the rate increase of $11,630,055, or a difference

[10] For consistency, PacifiCorp applied this same method to the Revenue Requirement model.
[11] The average price paid by USM for both firm and non-firm power during 2003 was as noted earlier in this report, $23.94. However, the COS results are the average price for firm power only. (see ITF notes 11-17 Attachment 2)

between the cost of service and the revenues received by USM of $1,343,731. This would indicate a required COS rate of 23.35 mills ($11,630,055/498,097 MWH). If the benefit to Utah is assumed to be $3,470,183, as derived above, the required COS rate is 22.28 mills ($11,099,445/498,097 MWH) with an associated revenue requirement shortfall of $813,121.

In data request, PacifiCorp provided an alternative assessment of the revenue requirement shortfall associated with a firm rate of service to USM at 21 mills. PacifiCorp calculated that this rate provided a discount to USM of $6.9 million, based on a comparison to schedule 9 rates.[12] PacifiCorp calculated the difference as follows:[13]

New Schedule 9 Average Tariff Price per MWH	$34.80
USM Contract price per MWH	$21.00
Economic Curtailment Discount per MWH	$13.80
Test Period MWH	498,000
Shortfall	$6,872,400

Using the PacifiCorp estimated reduction in Utah's revenue requirement of $2,939,573 due to allocation benefits, would indicate that there was a $3,932,872 revenue requirement impact on other customers. The required revenues from USM in the test period would then have been $14,219,196 indicating a required firm rate of service of 28.5 mills, or 1 mill below the firm rate identified in the filed revised COS. Using the adjusted revenue requirement reduction of $3,470,183, the estimated impact is $3,402,217. This implies that USM's revenues based on test period results should be $13,688,541. The required firm rate of service wold then be 27.48 mills, or approximately 1.77 mills below the rate indicated in PacifiCorp's filed revised COS.

Arguably, USM operates very differently than the average Schedule 9 customer. It is this "uniqueness" that has warranted special contract treatment. Thus comparison's to Schedule 9 rates of service may not be appropriate. USM continues to argue that USM has never been a firm service customer and, from the contract inception, the cost of providing service has been based on covering USM's (and predecessor companies) variable cost and making a contribution to fixed cost.

IRP Evaluations

Integrated Resource Planning (IRP) evaluations represent another method of attempting to value interruptibility. A number of IRP evaluations of either interruptibility or demand-side management have been performed. The Task Force specifically requested some studies. Others were provided in conjunction with PacifiCorp proposed

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13 PacifiCorp response to DPU data request 2.1.

DSM measures or in the context of the formal 2002 filed IRP. Information from these studies can be useful in the attempt to assess the appropriate value for the USM interruption, and interruptibility in general. Each of these studies is discussed below.

2003 IRP Value for Class 1 DSM

The 2003 IRP value for a Class1 DSM project for 150 MW at a 1% load factor, or approximately 88 hours annually, is nominally valued at $62/kw-yr.[14] For this study, PacifiCorp manually chose the highest hours of demand for approximately 12-15 days. These are the summer super peak hours but not necessarily CP hours and not always the most expensive hours. For Class 1 DSM programs it is assumed that PacifiCorp has direct control to bring the load off the system. Applying the $62/kw-yr value to the USM load (actual loads for 2003) as in IRP leads to an estimated credit of $6.37/MWH. If USM's potential load of 85 MW is assumed, the credit is $7.69/MWH.[15] (See Attachment B page 1)

Interruptible Task Force: Sample Price Results

In response to an informal data request made by the Interruptible Task Force, PacifiCorp provided IRP supply-side valuation scenarios. Eight scenarios were provided, with at least one of the runs being specifically relevant to the analysis of the USM interruption. The run assumed an 85 MW load that was interruptible for up to 500 hours annually.[16] It was also assumed that the customer could not buy-through the interruption.[17] Additionally, an assumption of "fixed sales" was applied.

PacifiCorp was concerned about what it refers to as the "Double Counting Problem." Essentially, capital costs are embedded in market prices. If customers were paid a "market rate" and a capacity credit, then they would receive a "double credit" for capacity. However, the attempt was to calculate "avoided cost "rates not market rates. As such, it could be assumed that avoided cost is calculated on the basis of turning down other units and is based more on marginal fuel costs than actual market prices. PacifiCorp contended that this may be true in off-peak hours but not necessarily in on-peak hours, which is the primary time frame for preferred interruptions. The fixed sale analysis was an attempt to resolve this issue by allowing for the provision of a capacity payment in the analysis but fixing the sales that could be made in the model.

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[14] 2003 IRP Appendix G.
[15] Values assume actual interruption and no buy-through.
[16] Two additional runs for an 85 MW load were also run; one run assumed a 40% load factor while the other assumed a 20% load factor. The 500-hour run is the closest to the type of interruption provided by USM in 2003.
[17] PacifiCorp has stated in the context of the Task Force that the "buy-through" option when applied reduces the value of the interruption. This is in part related to the fact that when the customer buys though there is still stress on the transmission system.

In the IRP supply-side valuation of the 85 MW load interruptible for up to 500 hours annually the average nominal cost of the interruption over a twenty year planning horizon (2005-2024, inclusively) was estimated at $109.89/MWH.[18] Applying this to the USM consistent with 85 MW load, or about 685,032 MWH annually, leads to credit value of $6.81/MWH. (However, USM's 2003 load was 572,570, leading to an estimated credit value of $5.66/MWH (See Attachment B, page 2.) It should be noted that the estimated reduction values are based on the assumption of actual interruption without any buy-through.

Subsequent to a Task Force discussion on the IRP Supply-side valuation with fixed sales, the DPU requested that PacifiCorp provide a similar analysis with "no fixed sales," a scenario that would better reflect actual cost to PacifiCorp's system. Under this scenario, the average annual cost stream was $74.44. Applying this to the USM load of 685,032 generates a credit of $4.62/MWH, while applying it to the 2003 actual load leads to a credit of $3.84/MWH. (See Attachment B, page2.)

It is the Division's understanding that the Fixed Sales Sample Price method as discussed here was found to be unacceptable by a number of parties and also by PacifiCorp. The method was also used preliminarily to consider valuations for Qualifying Facilities greater than 1 MW. The approach, both with and without the fixed sales assumption, was replaced in that process with a more traditional Avoided Cost calculation method, and this continues to be an issue under the Avoided Cost Task Force resulting from docket 03-035-14. However, we felt that is was important to review this range of values here to highlight the variability in valuations when different methods and assumptions are employed.

IRP 91 MW Valuation: "Cool Keeper Evaluation"

In support of its filing for the "Cool Keeper" program, PacifiCorp provided an estimated value for 91 MW of DSM at about a 1% load factor, or approximately 100 hours annually. The average nominal value over the 10-year planning horizon for the 91 MW of DSM was estimated at $100.59. Assuming an 85 MW load for USM, the estimated credit value based on this analysis is $12.48/MWH. Utilizing USM's 2003 load (closer to 59 MW) yields an estimated credit of $10.36/MWH.[19] (See Attachment B, page 3.)

Other Considerations for Valuation

Peaker Valuation

[18] This is a simple undiscounted average over the 20-year period.
[19] Again, the values assume actual interruption with no buy-through.

Both PacifiCorp and USM provided analysis of the interruptibility value based on a comparison to the cost of a peaker plant. USM's analysis indicated a credit value range under the comparable peaker cost scenario of $12.94/MWH to $14.56/MWH. An explanation of this analysis is provided in Confidential Attachment C to this report with the associated work papers contained in Confidential Attachments C.1, C.2, and C.3).

PacifiCorp also provided an equivalent resource evaluation. Under this analysis PacifiCorp evaluated a range of values based on the availability of interruptible hours. (See Attachment B page 5). For interruptible availability of 500 and 100 hours, PacifiCorp calculated that the annual credit would be $24.57 and $49.13, respectively. Applying these values to the USM maximum load of 85 MW yields respective credits of $1.52/MWH and $6.09/MWH on a monthly basis. Applying the analysis to USM's actual 2003 load yields monthly credits of $1.26/MWH and $4.23/MWH. (See Attachment B, page 4).

Interruptibility as Reserves

Currently, at least two interruptible customers on PacifiCorp's system provide non-spinning reserves through contracted interruptibilty arrangements. In response to DPU data request 1.12, PacifiCorp noted that USM has not demonstrated that it can be offline to meet WECC criteria for reserves.[20] USM has, however, stated in the context of Interruptible Task Force meetings that it believes it may be able to meet the criteria.

PacifiCorp stated that if USM could demonstrate such ability an additional issue would be whether or not reserves would be required in the Eastern control area. If USM could demonstrate that it meets the WECC criteria and Eastern reserves were required, PacifiCorp has stated that the valuation would be done on a basis similar to other interruptibility contracts based on provision of operating reserves.

Given recent concerns regarding resource adequacy in the West in general and in PacifiCorp's Eastern control area in particular, the Division believes that additional reserves may very well be required. If USM could demonstrate compliance with the required WECC criteria, the Division supports that reserve opportunities should be explored with USM.

[20] WECC requires that a load must be capable of physical interruption within 15 minutes to qualify as reserves (WECC Minimum Operating Reserve Requirement). However, PacifiCorp uses a 10 minute standard to offset the risk that the customer's load may be unavailable for interruption requiring it to call on other reserves.

IV. SUMMARY

Assuming that USM could comply with the necessary terms of interruption associated with the values discussed above, it appears that there is a possible range of "credit values." A determined credit could be applied to a firm rate of service based on firm annual usage. The firm rate of service identified in the PacifiCorp COS study is not for a full twelve-month period. In particular, USM's costs and revenues for the buy-through period are removed, as discussed above. Additionally, the CPs for the months of June-September are backed out for USM, as it is assumed that USM does not contribute to the system coincident peak in those months. Given these adjustments, the firm rate identified in the COS is likely to be lower than the firm rate that would apply if USM received 12 months of firm service. However, the load factor assumed in the COS is lower that USMs load factor absent interruption (approximately 70 in the COS whereas historically USM has had a load factor closer to 90.) Thus, the COS does not define the firm rate of service for USM for a 12-month period with its equivalent load factor.

Assumptions can be made to estimate what the COS to USM would have been had the loads during the interruption periods over the four months, June-September, not been removed from the COS. First, PacifiCorp provided in response to data request that USM purchased 42,807 MWH of buy through power. If this power is added to the USM loads in the COS, USM's load increases to 540,904 (498,097 + 42,807). Second, the cost of the buy-though power needs to be added back to the cost to serve USM. Additionally, Utah would not have realized a reduction in its revenue requirement associated with reduced contributions to system peak had USM not provided the interruption.

Assuming that this full cost (CP reduction plus power cost reduction) is assigned to USM, this leads to a rough estimate of the firm rate of service of 32.37 mills, [calculated as ($14,569,628+$2,939,573/540,904 MWH)]. Assuming that this is a close approximation of the firm rate of service to USM, credits could be deducted based on the interruption provided by USM.

The table below summarizes the credit values derived from the various IRP and comparable resource valuations identified in the discussion above and the associated rate of service to USM utilizing a firm rate of 32.37 mills.

Source	Load	Load Factor	Hours	Source Value	USM Value	COS Firm Rate*	Unadjusted Int Rate
IRP 2002	85 MW	1%	87	$62/kw-yr	$7.69	32.37	$24.68
IRP 2002	59 MW	1%	87	$62/kw-yr	$6.37	32.37	$26.00
ITF Sample Prices (fixed sales)	85 MW	>5%	500	109.89/MWH	$6.82	32.37	$25.55
ITF Sample Prices (no fixed sales)	85 MW	>5%	500	$74.44/MWH	$4.62	32.37	$27.75
ITF Sample Prices (fixed sales)	59 MW	>5%	500	$109.89/MWH	$5.66	32.37	$26.71
ITF Sample Prices (no fixed sales)	59 MW	>5%	500	$74.44/MWH	$3.84	32.37	$28.53
Peaker Value	85 MW	6%	500	$24.57/MWH	$1.52	32.37	$30.85
Peaker Value	59 MW	6%	500	$24.57/MWH	$1.26	32.37	$31.11
Peaker Value	85 MW	11%	1000	$49.13/MWH	$6.09	32.37	$26.28
Peaker Value	85 MW	11%	1000	$49.13/MWH	$4.23	32.37	$28.14
ITF 91 MW (Cool keeper Method)	91 MW	1%	87	100.59/kw-yr	$12.48	32.37	$19.89
AVERAGE							**$26.86**

As discussed in the COS section above, at least two other possible rates can be identified. Using PacifiCorp's method without the adjustment to NPC made by the Division, a rate of 23.35 mills is derived. With the Division's adjustment to NPC to reflect the higher power cost purchases in 2003, the derived rate is 22.28 mills. In summary, the range of possible values from all studies, excluding the equivalent resource calculation made by USM, is from 22.28 mills to 30.85 mills.

V. RECOMMENDATION

In sum, the Taskforce explored numerous approaches for quantifying the interruptibility value provided by USM, but did not identify a particular approach as definitive. Additionally, it is the DPU's assessment that the analyses do support that large interruptible customers offer value to the system and to Utah ratepayers, as realized through power costs adjustments and reduced contributions to the CP leading to lower revenue requirement allocations. However, analyses done to date also seem to indicate that a rate of 21 mills for service to USM is too low, but that a firm schedule 9 rate is too high. Under the COS analysis with all benefits of the USM interruption credited to USM, Division staff calculates that a rate of approximately 22.28 mills is the lowest rate under the current terms of interruption that could be supported by cost of service evaluations.

To date, IRP analyses vary significantly in the outcomes making it difficult to rely on the IRP approach. The "equivalent resource" approach also suffers from the same difficulty, which is that changes in assumptions can lead to widely varying results. Thus, the Division recommends the following:

- USM interruption should continue to be tracked, as is anticipated for the Summer 2004 interruption period
- The COS model should be updated to account for increases in USM's load, as would be pursued during a rate case
- PacifiCorp should file as part of any rate case the revenue requirement "savings" resulting from USM interruption
- The COS model should continue to be used as a benchmark for evaluating USM's interruptibility value through the term of its current contract, or until such a time that the interruptibility terms are modified
- USM on a going forward basis should continue to receive an "interruptible" rate as it can be shown that there are potential benefits to Utah ratepayers from such interruption.
- Possibilities for USM to provide additional reserves should be explored and if USM demonstrates it can meet WECC reserve criteria, PacifiCorp should provide the reserve value based on the Monsanto approach
- Efforts should be made in the IRP process to more clearly define the modeling assumptions for interruptible loads in order to derive more consistent valuations; we would expect that the analysis from the Avoided Cost Task Force will provide useful insights to this method

The Division believes that these recommendations are consistent with the analyses done so far on the USM interruption. Additionally, we support that providing interruptible rates and service for large special contract customers is consistent with the Division's focus on the need to further pursue demand side options for managing Utah's load growth. Moreover, consistency in valuations should be pursued through the IRP process to allow for clearer consideration of the range of cost effective alternatives.

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