ORDER NO. 07-446

ENTERED 10/17/07

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UE 191

In the Matter of	)	
	)	
PACIFICORP, dba PACIFIC POWER	)	ORDER
	)	
2008 Transition Adjustment Mechanism.	)	

DISPOSITION: NET VARIABLE POWER COSTS APPROVED, SUBJECT TO ADJUSTMENTS ADOPTED IN DECISION

I. BACKGROUND

In Order No. 04-516 (Docket No. UM 1081), the Public Utility Commission of Oregon (Commission) adopted an interim transition adjustment mechanism (TAM) for PacifiCorp, dba Pacific Power (Pacific Power) to use for direct access during the fall 2004 open enrollment window. The Commission stated its desire was to develop a TAM that values resources based not only on Pacific Power's actual operational responses, but actual operational responses that are based on appropriate planning. In Order No. 04-516, the Commission ordered Pacific Power to file a TAM by November 15, 2004.

Pacific Power complied with the Order by filing its TAM, as part of its general rate case filing. (Docket UE 170) In Order No. 05-1050, the Commission adopted the TAM proposed by Pacific Power in UE 170, with annual updates and specific 2006 adjustments agreed to by the Public Utility Commission Staff (Staff) and Pacific Power.

In Order No. 05-1050, the Commission Staff observed that the purpose of the TAM is not to promote direct access. Rather, the purpose of the TAM is to capture costs associated with direct access, and prevent unwarranted cost shifting. Having adopted the TAM, however, the Commission Staff expressed its view that further investigation into some of the concerns raised by the parties would be necessary. The Commission Staff noted that it was "somewhat concerned" about establishing the TAM with its annual update because of the one-sidedness to Pacific Power's annual updates without concomitant adjustments by intervenors and Staff. The Commission Staff stated that it would continue to look at the TAM and "investigate to whatever extent we believe is necessary."

Pacific Power's next TAM filing was in docket UE 179, another general rate case. TAM related issues were resolved in a stipulation that was approved by the Commission in Order No. 06-530. That stipulation included a provision "capping" the net power cost update for the 2007 TAM at $10 million. It did not cap or otherwise alter the calculation of the Transition Adjustment or net power cost update for years subsequent to 2007.

In principle, the TAM is the difference between the weighted market value of the energy previously used to serve Direct Access customers and the cost of service rate under the customers' specific, energy-only tariff schedules. To determine the value of the energy previously used to serve departing customers, Pacific Power runs two studies using its Generation and Regulation Initiatives Decision Tools (GRID) model for each customer class. The base study optimizes Pacific Power's system with the full expected load for the next calendar year. The second study re-optimizes the system with a 25 MW reduction in Oregon load.

Procedurally, in October 2007, prior to the posting of indicative prices, Pacific Power will update net power costs to reflect changes to Commission-ordered net power costs, the current forward price curve, new contracts and/or updates for wholesale sales, purchases, fuel and wheeling expenses through September 15, 2007. In November 2007, just prior to the direct access open enrollment window, the Company will produce a final GRID study incorporating its most recent forward price curve. The final GRID study will establish the Transition Adjustment and total Company net power costs for calendar year 2008.

The net power costs are defined as the sum of fuel expenses, wholesale purchase power expenses and wheeling expenses, less wholesale revenue. The net power costs are calculated for a future test period based on projected data using the GRID model. The net system load, wholesale sales and purchase power expenses, wheeling expenses, market prices of natural gas and electricity, fuel expenses, hydro generation, thermal heat rates, thermal planned maintenance and outages inputs were updated for this filing.

II. INTRODUCTION

Pacific Power submitted its testimony and exhibits on April 2, 2007. At the prehearing conference a schedule was adopted that anticipates a decision in this docket by October 19, 2007.

Reply testimony and exhibits were submitted by the Staff, the Citizens' Utility Board of Oregon (CUB) and the Industrial Customers of Northwest Utilities (ICNU) on June 27, 2007. On July 25, 2007, Pacific Power submitted rebuttal testimony and exhibits.

On August 8, 2007, Staff and ICNU each filed motions requesting the right to file supplemental testimony in response to Pacific Power's rebuttal testimony. Pacific Power opposed Staff's motion. Pacific Power did not oppose ICNU's motion. Staff's motion was granted. Pacific Power was allowed to file surrebuttal testimony in response to Staff's supplemental testimony.

There were two days of hearing in this matter. The case was submitted on concurrent opening and closing briefs.

III. PACIFIC POWER PROPOSAL

In its initial filing, Pacific Power calculated that its Oregon-allocated forecasted normalized net power costs for calendar year 2008 would be about $253 million – "approximately $36 million higher than the net power costs in its Oregon rates for 2007 " – based on the Company's total forecasted normalized system-wide net power costs for the test period of about $1 billion. The five primary drivers of the higher rates are higher coal prices, higher gas costs, the expiration of the 2007 TAM cap, expiring purchase power contracts and system load growth.

According to Pacific Power, the coal price increases are being driven by a variety of factors, including normal increases in contract price indices and the impact of contract re-openers, market price increases for Power River Basin coal, the acquisition of higher-priced compliance coal necessary to meet environmental standards, and union labor costs. Pacific Power characterizes these increases as typical for the industry.

Pacific Power states that gas prices have trended sharply upward over the last several years and remain volatile, with price spikes and price softening. This makes hedging to manage extreme gas price changes an important risk mitigation tool. Its forecast gas costs reflect market prices, plus cost increases or decreases to reflect its hedging position.

Regarding the $10 million cap of its 2007 TAM increase, Pacific Power states that its total system net power costs for 2007 would have been about $40 million higher without the cap. When comparing its 2007 net power cost forecast of $1.002 billion with its 2007 TAM of $834.4 million, Pacific Power states that "it is important to keep in mind the additional $40 million of 2007 net power costs that were not recovered through the 2007 TAM."

Regarding the expiring purchase power contracts, Pacific Power states that such contracts reflect wholesale market prices at the time they were executed. As wholesale electric market prices increase, the cost of replacement power increases when a contract expires. The TAM reflects the impact of the expiration of various contracts, including the 400 MW TransAlta contract, and the increased costs of replacement power associated with these expiring contracts.

The load forecast shows an increase of 2.8 percent over loads currently reflected in rates. However, the impact of the load growth on this filing is mitigated by application of updated allocation factors that reduce Oregon's proportionate share of system power costs.

Pacific Power observes that the cost increases in its TAM filing are partially offset by the ratemaking treatment of its 525 MW Lakeside combined cycle combustion turbine (Lakeside). Because the capital costs of Lakeside were not included in the Company's last general rate case, Oregon customers will pay only the relatively low variable costs associated with this resource until the capital costs are included in rates in the next general rate case.

According to Pacific Power, the cost increase is also partially offset by the inclusion of the variable costs from renewable energy facilities expected to be in service during the test period, including the Goodnoe East and West wind facilities in Oregon and the Marengo wind facility in Washington. The net power costs also include the output of the Leaning Juniper wind facility that came on line in the fall, 2006. Because Pacific Power owns these wind facilities, the variable cost of their kWh included in the net power costs is zero.

In July 2007, Pacific Power updated its TAM filing. It calculated total company net power costs at $979.5 million, a reduction of $21.5 million from the forecast of $1 billion in its original filing. In its testimony the Company listed a number of contract data and forward price curve updates that it incorporated into the GRID results.

On an Oregon allocated basis, the Company's forecasted normalized power costs for calendar year 2008 are $247 million, approximately $29.6 million higher than the net variable power costs (NVPC) in Oregon rates for 2007 (by the Company's calculation). This would result in an overall increase to net rates of about 3.2 percent.

Pacific Power's July TAM filing update and rebuttal testimony reflects Pacific Power's adoption of the following adjustments and policy recommendations by Staff, ICNU and CUB:

Staff

Operating Reserve Adjustments: Pacific Power adopted the operating reserve correction proposed by Staff, reducing proposed total company net power costs by $15.8 million.

Carbon Generation Plant: Pacific Power adopted Staff's proposed Carbon generation plant adjustment, reducing total company net power costs by $4.8 million.

Stochastic Net Power Costs Modeling: Pacific Power agrees to Staff's recommendation that the Company file a written report to the Commission on the feasibility of estimating NVPC using stochastic modeling.

ICNU

Extrinsic Value of Call Options: Pacific Power adopted a modified version of ICNU's proposal to impute extrinsic value for five call option contracts included in GRID, reducing the total company net power costs by $5.3 million.

Excess Revenue Allocation: ICNU proposed an adjustment, lowering Pacific Power's operating reserves. Pacific Power agreed to Staff's adjustment. ICNU accepts the adjustment.

CT Reserve Capability: Pacific Power accepted ICNU's recommendation to prospectively increase the quick start capability of the Gadsby and West Valley CTs, reducing total company net power costs by $0.2 million.

W-E Reserve Transfer: Pacific Power adopted ICNU's recommendation to leave the Company's West/East transfer capability turned on in GRID, reducing total company net power costs by $0.2 million.

Uneconomic CT Operation: Pacific Power accepted ICNU's adjustment removing West Valley from GRID, reducing total company net power costs by $1.6 million.

Planned Outages: Pacific Power agrees with a portion of the adjustment that reduces total net company power costs by an immaterial amount.

CUB

CUB-related issues are discussed in the body of the decision.

The total of these adjustments is $27.9 million, indicating that the net effect of the updates to other assumptions was to increase power costs by $6.4 million.

IV. ISSUES

A. *Staff*

1. *Staff Position*

Staff proposes an adjustment intended to recognize the positive margin on Pacific Power wholesale market transactions that are recognized by the GRID model. Staff attributes these results to "the wide reaching nature of Pacific Power's six-state power system."

The purpose of the GRID model is to simulate the actual operation of Pacific Power's power supply system. According to Staff, GRID systematically fails to capture nearly 75 percent of all short-term sales and purchase transactions. Staff states that the magnitude of this omission is "very significant." The omission averaged more than $16 million of profit margin on sales and purchase transactions as allocated to Oregon in the three years of available relevant history.

Staff defines the margin as "the difference between the average sales and the average purchase price times the average volume of omitted sales and purchase transactions." The volume of omitted sales and purchases is the difference in the MWh volume included in GRID and the actual MWh volume that occurs in the actual operation of the system.

Staff states that the volume of omitted sales nearly equals the volume of omitted purchases (within 2 percent). This means that the source of supply to make the omitted sales was the omitted purchases. Thus the margin adjustment to account for the omitted transactions is simply the difference in the two average prices multiplied by the sum of the purchases and sales.

Responding to Pacific Power, Staff states that it never has proposed a margin adjustment for Portland General Electric Company (PGE). Staff states that Pacific Power's power system has the capability to systematically produce positive margins on the additional wholesale transactions not captured by GRID, while PGE's power system does not have such a capability.

Staff makes a distinction between Pacific Power's total wholesale margin (which may be negative) and the "additional" MWhs of sales and purchases not included in the GRID model which it says is positive. Staff states that the omitted wholesale sales and purchase error is systematic and occurs every year. According to Staff, Pacific Power always makes a positive margin on the GRID-omitted sales and purchases because of the diverse nature of its system and the resulting advantageous circumstances.

Staff characterizes as "diversionary" Pacific Power's claim that different levels of resources and planned maintenance between the GRID model and actual results cause a mismatch of costs and benefits. Staff claims that it demonstrated the independence of the margin adjustment from any extrinsic value considerations.

Staff states that Pacific Power's calculations are based on total actual short-term sales and purchase activity, while Staff's adjustment pertains only to the sales and purchases not captured by GRID. The omitted transactions are total actual, less what is included in GRID forecast and included in rates. There are three years of useful data (UE 134, UE 147 and UE 170 test years) where GRID was used to forecast power costs, and the actual results for the test period are known. That is the data that Staff used.

Staff states that the realization of the positive margins takes effort and skill on the part of Pacific Power, and the Commission may consider sharing the benefits with Pacific Power's shareholders as an incentive. Staff believes customers should reap most, if not all, the benefits of a system they paid for.

2. *Pacific Power Reply*

Pacific Power argues that Staff's margin adjustment lacks the basic evidentiary foundation necessary to prove even routine adjustments, and has multiple theoretical and policy problems:

- Other than a general description, Staff did not introduce any evidence of the calculation of the adjustment.

- The record includes alternate calculations for this adjustment that Staff proposed in three other Pacific Power cases. Application of the alternate calculations produces very different results.

- Staff never attempted to determine what percentage of the additional transactions was related to trading (where the concept of margin is applicable) and what percentage were related to system balancing (where the concept is not). The undisputed evidence shows that system balancing comprised 87 percent of Pacific Power's total short-term transactions.

- Staff never tested its theory by comparing power costs in rates to actual results. Over the last five years, Pacific Power's power costs in rates were understated by more than $60 million per year (average).

- Staff's margin adjustment is inconsistent with the Commission's recent rejection of the Staff's extrinsic value adjustment in UE 180 (PGE), where the Commission recognized that the inherent value of power supply systems should be captured by comprehensive modeling changes.

- Staff's margin adjustment is problematic regulatory policy, because it imputes an actual cost model into a normalized ratemaking paradigm. The problem is compounded by Staff's failure to compensate for differences in actual results in variables that impact volume and margin on short term wholesale transactions, such as new resources not included in rates, hydro generation, fuel costs, and thermal availability.

Pacific Power elaborates on each of these points.

Regarding whether the evidence supports Staff's calculation, Pacific Power argues that Staff relies on the calculation as its only evidence that the Company makes a positive margin on its wholesale transactions not covered in GRID – without ever introducing the margin adjustment calculation into evidence.

According to Pacific Power, the evidence demonstrates that the margin adjustment calculation is highly volatile. When applied to earlier cases, Pacific Power claims that the margin adjustment calculations produce much different results from Staff's adjustment in this case.

Pacific Power challenges Staff's claim that its margin adjustment would always be positive. Pacific Power states that it has experienced implied negative margins on its total wholesale transactions in the last three out of five years.

Pacific Power states that its alternative adjustment calculations are the only margin adjustment calculations now in the record, with results that could be averaged to support a rate increase instead of a rate decrease. Pacific Power does not support Staff's margin adjustment, whether it results in an increase or decrease. Staff's adjustment is "unreliable," and "lacks consistency and predictability."

Regarding whether the transactions tend to be system balancing or trading, Pacific Power states that system balancing transactions have made up over 87 percent of Pacific Power's short-term transactions, with arbitrage and trading transactions comprising the balance. System balancing is a dynamic process that involves continuous rebalancing. For any given position, the Company engages in multiple system balancing transactions, resulting in large volumes of such transactions relative to its load.

Regarding its alleged chronic underrecovery of its system power costs, Pacific Power states that current results, through May 2007, show that total company power costs in Oregon rates are understated by $65 million. Staff has never compared Pacific Power's net power costs in rates to its actual results during the adjustment period.

Pacific Power likens Staff's proposed adjustment to Staff's proposed "extrinsic value adjustment" in PGE's last general rate case, docket UE 180. In that case, "the Commission recognized that a better outcome was to work toward a new power cost model that more comprehensively captures the costs and benefits of stochastic volatility," and announced that it would open a new generic docket to review the issue.

Pacific Power argues that the Commission should apply the same approach in this case – rejecting Staff's adjustment in favor of a more comprehensive review of power cost modeling in the generic docket announced in UE 180. It is unreasonable to make a one-factor, ad-hoc adjustment to power costs to capture certain benefits when power costs already are systematically understated in rates.

Regarding the "ratemaking paradigm," Pacific Power argues that Staff's margin adjustment is essentially an historical true-up adjustment for prior unrelated periods for short-term wholesale transactions within a power cost model that otherwise is based on normalized forecasts. If Staff's adjustment were adopted, consistency would require adoption of similar true-ups for other costs.

Pacific Power illustrates its point with the example of new resources that are not yet included in rates. In 2006, neither Pacific Power's Currant Creek CCCT nor Leaning Juniper wind farm were in rates in Oregon, but both came on line in that year and produced 1.9 million MWh. Pacific Power argues that Staff's margin adjustment unfairly includes the volumes and revenues from wholesale transactions associated with these plants, without any offsets for their associated costs.

Pacific Power states that GRID does capture the value of the operation of its system by using available transmission for trading and by backing down generation. GRID calculates this value on a normalized basis, consistent with the treatment of other net power cost components.

Pacific Power states that an hourly deterministic production dispatch model like GRID will always underestimate the volume of short-term transactions, because it balances loads and resources and optimizes the system with perfect foresight. Staff's margin adjustment is based only on the assumption that, because the volume of Pacific Power's omitted sales nearly matches the volume of its omitted purchases, the source of the omitted sales must be the omitted purchases.

Pacific Power says that assumption is false. The Company engages in an approximate equal number of sales and purchases to balance its system, and together these sales and purchases account for an average of 87 percent of Pacific Power's short-term transactions during the adjustment period. The source of virtually all sales omitted from GRID is Pacific Power's system resources, not omitted purchases. These sales and purchases are not linked or paired in a manner that produces a "profit margin."

Pacific Power compares the results of Staff's adjustment in this case to the results it calculated using Staff's methodology for prior cases and argues that "one would expect all versions of the margin adjustment calculation to produce generally consistent results in this case." Pacific Power cites their apparent inconsistency as "highly relevant evidence on the validity of the proposed adjustment."

Pacific Power reports that its actual, average margins on its trading ($0.8 million) are only 4.9 percent of the margin adjustment in this case. Staff's fatal flaw is that it does not attempt to distinguish between Pacific Power's "arbitrage and trading programs" from all sales and purchases not captured by the GRID.

3. *Staff Response*

Staff states that its margin adjustment is measured from three years of data, the only available years when there is data from both a GRID forecast for a year and the actual power operations results for that year. The results demonstrate a systematic and significant modeling problem: the actual MWhs of short-term sales and purchases exceed forecast by roughly 200 and 370 percent, respectively. Staff discredits Pacific Power's alternative calculations as irrelevant, because they use years for which both the GRID forecast and actual data are not available, or they use a different definition of margin.

Staff notes that Pacific Power relies on "system balancing" to explain why its power costs model grossly under forecasts actual volumes of wholesale transactions, but fails to demonstrate that positive margins cannot result from the dynamic process of system balancing.

According to Staff, positive margins are not only possible, they are systematic. A positive margin is produced on the wholesale transactions not captured by the GRID model because of the advantageous nature of the Company's diverse system. Staff calculates that Pacific Power's system balancing activity for 2006 yielded $25.6 million of positive margin allocated to Oregon.

Staff argues that Pacific Power's comparison of NVPC in rates and actual results is not relevant. Pacific Power's total actual power costs are impacted by many random factors, such as weather, hydro levels, market prices, natural gas costs, power plant forced outages and system load. The variation of these random variables can be addressed by stochastic power cost modeling. Staff's margin adjustment addresses the systematic, non-random, positive margin produced by the ever-present, intrinsic advantageous characteristics of Pacific Power's power system.

Staff believes that Pacific Power and PGE are in different situations regarding the capability of their power systems to systematically produce positive margins on the wholesale transactions not captured by their respective power cost models. According to Staff, "Pacific Power makes a positive margin and PGE does not."

Staff disagrees that the margin adjustment is related to an extrinsic value adjustment. Different levels of resources and different levels of planned maintenance between the GRID filed and actual results do not affect the margin on wholesale transactions not included in GRID. All of the additional MWh of energy to make additional sales not included in GRID is provided by the additional MWh of purchases not included in GRID. Extrinsic value comes from undispatched flexible power resources, not from wholesale sales and purchases.

Staff disputes Pacific Power's claim that its adjustment is poor regulatory policy. Staff's margin adjustment is necessary to account for the systematic problem with the normalized regulatory paradigm.

4. *Discussion*

It is undisputed that GRID underestimates the volume of short-term wholesale transactions. As Pacific Power explains, an hourly deterministic production dispatch model like GRID will always underestimate the volume of short-term transactions, because it balances loads and resources and optimizes the system with perfect foresight.

Thus, we accept Staff's premise that the GRID model systematically understates the extent of Pacific Power's wholesale market activities. From that premise Staff infers that Pacific Power receives a systematic positive return on its net short-term wholesale transactions that are not included in the GRID runs. Staff attributes that return to Pacific Power's ability to leverage the flexibility of its diversified system.

We do not adopt Staff's adjustment. Staff's approach attributes all of the "excess"[1] volumes to Pacific Power's wholesale trading activities and derives a margin from the difference in the average prices of purchases and sales that is the basis for its adjustment. The record does not support Staff's treatment of all wholesale transactions as "trades."

The record shows that 87 percent of Pacific Power's short-term transactions are for balancing. Pacific Power buys or sells energy to balance load and supply. At any time, Pacific Power may be a net buyer or seller of energy to balance its system. There is no

[1] "Excess" refers to the recorded volumes of purchases and sales above the forecasted volumes in the GRID model.

evidence of a systematic tendency toward either role, or of any net margin on such transactions.

The remaining 13 percent of Pacific Power's short-term wholesale transactions are properly attributed to Pacific Power's arbitrage and wholesale trading activities. The Company calculated that the Oregon allocated margins on such activities averaged $0.8 million annually (from 2003 through 2006). There is no evidence that those results are included in the GRID model results. However, we conclude that such revenues are properly considered in the calculation of NVPC and the model results should be adjusted as necessary to incorporate those revenues.

We invite the parties to look more closely at the GRID model to examine whether there is a systematic bias in the way it treats short-term wholesale energy transactions, both for system balancing and for arbitrage and trading.

B. *ICNU*

1. *NVPC Baseline*

a. ICNU/Staff Position

ICNU argues that Pacific Power has inflated the rate increase by understating the amount of net variable power costs (NVPC) currently assumed in rates. ICNU contends that the amount of NVPC currently in rates is $225 million, not the $217.5 million assumed by Pacific Power. According to ICNU, the dispute over the amount of NVPC now in rates centers on the amount of NVPC the Commission authorized in Pacific Power's last general rate case (docket UE 179), determined by a stipulation between the parties. The relevant provisions of the Stipulation are attached as Appendix A.

ICNU claims that the amount of NVPC in rates approved in UE 170 was about $215 million. The UE 179 Stipulation then provided for an increase in the NVPC of $10 million. ICNU's calculation in this case is the simple sum of $215 million and $10 million.

Staff supports ICNU's proposed $7.5 million adjustment. According to Staff, when Pacific Power received the $10 million increase in NVPC in UE 179, it reflected an Oregon allocation based on the increase in total system NVPC from $796.5 million in UE 170 to $834.4 million in UE 179. However, this calculation did not reflect the $7.5 million decrease resulting from adjusting the Oregon allocation factor from 26.99 percent in UE 170 to 26.09 percent in UE 179. Thus, current Oregon rates include NVPC of $225 million (26.99 percent of $834.4 million)

b. Pacific Power Response

Pacific Power offers "seven reasons" why the Commission should reject ICNU's adjustment.

First, the adjustment is contrary to the express terms of the UE 179 Stipulation, signed by ICNU and approved by the Commission in Order No. 06-530.

Second, the adjustment effectively substitutes "total company" in Section 5.b(v) of the UE 179 Stipulation with the words "Oregon allocated."

Third, Section 10 of the Stipulation expressly binds the parties to use the Section 5 methodology (NVPC calculation) in future cases.

Fourth, ICNU's calculation produces a total company NVPC that causes a violation of the stipulation, because it corresponds to a total company NVPC for 2007 of $861 million, whereas the Stipulation sets the NVPC cap for 2007 at $834.4 million.

Fifth, although ICNU's NVPC baseline can be derived by applying UE 170 allocation factors to the $834.4 million NVPC cap, Pacific Power has used the appropriate (but lower) UE 179 allocation factors to derive the $217.5 million baseline.

According to Pacific Power, in the UE 179 Stipulation, the parties agreed to calculate the NVPC/TAM increase by comparing total company power costs from UE 170 and UE 179 and allocate the difference using specified UE 179 allocation factors. Pacific Power argues that ICNU is attempting to revisit its bargain in UE 179 by reworking the 2007 NVPC calculation using UE 170 allocation factors instead of the UE 179 allocation factors.

Sixth, Pacific Power's final TAM/total company NVPC filing in UE 179 was about $40 million higher than the UE 179 cap of $834.4 million. Pacific Power argues that, having benefited from the cap, it is unfair for ICNU to ignore the cap and impute a higher NVPC in rates for 2007.

Seventh, ICNU's theory illustrates the problems that can arise in the context of negotiated settlements and changing allocation factors. According to Pacific Power, ICNU's approach is inconsistent with how overall rates were set in UE 179.

In its reply brief, Pacific Power argues that ICNU's approach selectively applies only one of the several express requirements of the Stipulation. ICNU's proposed NVPC baseline violates the Stipulation on its face because it produces a total company 2007 NVPC baseline that exceeds $834.4 million.

Pacific Power further argues that ICNU's position amounts to a regulatory "Catch 22," where the cap is applied first to reduce the rate increase in UE 179 and then ignored to reduce the rate increase in this proceeding. Pacific Power argues that this result is contradicted by the express language of the stipulation.

Pacific Power argues that the stipulation established the methodology for calculating the 2007 NVPC/TAM revenue requirement for this and other cases, not just the UE 179 TAM increase. The Company cites language in Order No. 06-530 that it believes supports this claim.

Pacific Power argues that the Commission should interpret the stipulation according to its express terms, because the Commission's rules bar the consideration of extrinsic evidence of the parties' intent. If the Commission were to conclude that the Stipulation is ambiguous, however, then Pacific Power requests an opportunity to offer extrinsic evidence regarding the settlement negotiations.

Replying to Staff, Pacific Power argues that the Stipulation specifically provided for allocation of the total Company NVPC amount of $834.4 million to Oregon, using specified UE 179-based allocation factors. Thus, Oregon customers already received the benefit of the decline in Oregon allocation factors from UE 170 to UE 179.

c. ICNU/Staff Reply

According to ICNU, the UE 179 stipulation identifies the NVPC rate increase and provides the formula to calculate the $10 million rate increase. There is no indication that this formula would be used to set the amount of NVPC in rates in perpetuity.

ICNU states that it recognizes that the UE 191 stipulation did not pass to Oregon the full benefits of the lower allocation factors, and ICNU is not seeking to alter that settlement. ICNU did not agree that Oregon ratepayers would be denied the benefits that accrue to Oregon's lower-than-average load growth in all future proceedings.

ICNU states it is not revisiting or changing the amount of the NVPC rate increase that was granted in UE 179. ICNU asks the Commission to recognize that Pacific Power was granted a $10 million NVPC rate increase in UE 179 that should be added to the undisputed UE 170 NVPC of $215 million to establish NVPC in rates of $225 million.

According to Staff, ICNU is correct that the total system NVPC of $834.4 million, in the UE 179 Stipulation, was used only to determine whether to grant the $10 million increase. If the $834.4 million had been used to determine the total NVPC to be allocated to Oregon, instead of being used just to determine the increase, then the Oregon allocated NVPC would have been $217.5 million, instead of the $225 million the company received.

d. Discussion

At issue is: What is the amount of NVPC that was in rates in UE 170?

This question arises because the Stipulation states: "the NVPC/TAM rate increase is capped at a maximum of $10 million, and under no circumstances would it be greater than $10 million." No party disputes that the amount of the increase was $10 million.

Based on the record, we believe the "increase" was above the amount that was in rates in UE 170. On a system basis, the amount of NVPC in UE 170 was $796.5 million. Using the 26.99 percent Oregon allocation factor that was applied to calculate the NVPC in UE 170, the resulting amount in rates was $215 million. Adding the $10 million increase from UE 179 raises the level of NVPC in rates to $225 million, as argued by ICNU and supported by Staff.

Pacific Power derived its figure by taking the lower UE 179 allocation factor (26.09) and applying it to the amount used to determine the UE 179 cap: $834.4 million. The result is $217.5 million, the basis for Pacific Power's calculation.

We believe, based on the record, the $834.4 million figure in UE 179 was not used to set the amount of NVPC in rates. It was used only to determine the amount of the cap.

The difference between the $796.5 million in UE 170 and the $834.4 million in UE 179 is $37.8 million. Applying the 26.09 percent allocation factor to $37.9 million results in about $10 million.[2]

This outcome does not violate the terms of the Stipulation. This result is required by the terms of the Stipulation. The resulting adjustment is about $7.5 million.

2. *Outage Rates*

a. ICNU Position

ICNU states that Pacific Power's forced outage rates have substantially increased over the past decade, resulting in higher power costs. ICNU argues that the Commission should remove from Pacific Power's NVPC the costs associated with forced outages "that were caused by management or personnel errors, avoidable mistakes and/or manufacturer design flaws."

ICNU notes that Pacific Power uses the most recent four-year historical period to calculate the outage rates for its thermal plants. ICNU proposes to remove from that

[2] Appendix A, p. 17 of the Stipulation erroneously displays the allocation factor as 26.40 percent. (Staff Reply Brief, p. 6)

period, those outages that were caused by manufacturer defects, poor company management, personnel errors, and factors within the control of Pacific Power,

According to ICNU, since 1999, Pacific Power's outage rates used to set NVPC had increased by more than 40 percent, and 77 percent of Pacific Power's generating units have seen their outage rates increase over the past seven years.

ICNU notes that Pacific Power's four-year forced outage rates have improved over the past three years. However, ICNU claims that Pacific Power did not analyze whether this improvement is due to the removal of the catastrophic Hunter outage from the four-year outage rate, or represents an actual improvement in reliability.

ICNU's analysis of Pacific Power outages excluded the impacts of the Hunter outage. According to ICNU, Pacific Power's most recent four-year equivalent forced outage rate for the four-year period ending 2005 is higher than any comparable four-year period in the past fifteen years.

ICNU's analysis focused primarily on outages in 2006. ICNU recommends that the Commission remove from Pacific Power's outage rates a group of small outages the Company itself identified as being due to operator or personnel errors, and fourteen larger outages that were "due to poor management, personnel or maintenance errors, or other avoidable causes."

ICNU argues that Pacific Power has the burden of proving that all of its proposed costs would be prudently incurred. Pacific Power has failed to present evidence that the outages challenged by ICNU were prudent.

In its brief, ICNU describes causes of some of the outages, as reported in Pacific Power's outage reports, or "Root Cause Analysis" (RCA).[3] These include the following events:

> An outage that was directly caused by the failure of Pacific Power personnel to install certain equipment properly and "because Pacific Power did not establish a policy to install adequate monitoring equipment."
>
> An outage classified as an operator error. The RCA report finds the ultimate cause of the outage was senior management's failure "to establish a policy to review the effect of changing quality" and the resulting failure to "fund redesign of reheater and sootblowers." The report also blames engineering for failing to propose improvements to the reheater, not updating the tubing plan, failing to identify alternate inspection technologies, and not requesting that the Company purchase

[3] Much of the discussion of this issue in ICNU's brief involves confidential documents that were received under seal. In this decision, we do not identify the individual plants or dates of the outages that are the basis for ICNU's claims.

"appropriate inspection equipment." The report also blames plant management for not establishing a policy to inspect for problems.

An outage caused by the combination of personnel error and a poor management decision to defer maintenance. The outage was directly caused by a welding defect that was the result of cost cutting measures that put earnings above long-term plant reliability. The RCA report indicated that the boiler that had the welding defect had been scheduled for replacement, but that had been put off for four years, due to budget cuts.

An outage caused by maintenance errors. The specific cause of the outage was a tube leak. The problem had occurred in the past, and had been "fixed" with an incorrect type of tubing.

An outage caused by an operator error of running the boiler too hard for coal quality, resulting in slag buildup on the division walls.

Two outages caused by "operator error."

An outage caused by improper wiring as a result of a faulty repair.

An outage caused by the operator running the unit beyond recommended load limits while operating the unit with a known tube leak. The RCA report recommended that Pacific Power should take the unit off line sooner, when there are known tube leaks.

An outage caused by operator error.

An outage that occurred after a prior repair had failed to detect the full extent of the repairs required.

A number of small events that the Company reported to the North America Electric Reliability Council "as being due to operator or personnel error."

ICNU also argues the Commission should remove from Pacific Power's outage rates an outage that was the result of a design flaw from Siemens-Westinghouse. Even where the utility is not negligent, ICNU argues that the utility is better suited to pursue remedies for any manufacturing defects than are the rate payers, citing Re PGE, Docket No. UE 88, Order No. 95-322 at 3, 62.

b. Pacific Power Response

Pacific Power observes that in PGE's last general rate case, UE 180, parties argued for different methods of calculating PGE's forced outage rate, other than the rolling four-year average. This Commission rejected use of other methods to forecast reliability and decided to continue to use the four-year rolling average method:

In determining a method for establishing the forced outage rate, we seek the most accurate forecast of forced outages at the relevant plants. We continue to believe that past performance is the best predictor of a plant's outage rate. For this reason, we adhere to our long-standing practice of using actual plant outage rates to predict the future activity of that plant. (Order No. 07-015 at 15.)

Pacific Power states that its TAM filing conforms to Order No. 07-015.

Pacific Power observes that in Order No. 07-015 the Commission also recognized a need for a policy-based generic review of the calculation of forced outage rates for ratemaking. In that order, we stated it we would open a new generic docket to examine this issue.

Pacific Power argues that there are several policy issues implicated by ICNU's proposed adjustment that should be addressed in the Commission's generic proceeding, rather than in this case.

First, Pacific Power argues that ICNU ignores data demonstrating that Pacific Power's overall plant performance matches or exceeds industry averages. ICNU's emphasis on isolated mistakes or errors, rather than overall plant management, sets poor regulatory policy and could lead to an approach to plant management that reduces outages but raises costs.

Pacific Power further argues that ICNU's proposal to charge the utility with outages due to manufacturer problems raises complicated policy issues. To impute a prudence disallowance based on manufacturer error significantly lowers traditional prudence standards in Oregon and overstates the holding in the PGE case. (Order No. 95-322.)

According to Pacific Power, the Commission's holding in Order No. 95-322 "was expressly limited to the UE 88 case." The scope of the Commission's prudence standard in the context of plant outages caused by manufacturer defects, and the interpretation of the UE 88 order, is more appropriate to a generic policy docket than to this proceeding.

Pacific Power also objects to ICNU's reliance "on selected portions of selected Pacific Power root cause reports." ICNU has taken "reports that are developed and maintained for prudence purposes and inappropriately uses them to establish imprudence."

According to Pacific Power, ICNU's use of the outage reports in this manner could discourage utilities from carefully reviewing and remediating specific outage incidences. There is a strong public policy against using evidence of subsequent remedial measures to prove imprudence, because the logical consequence of such a finding would be to decrease incentives to take preventive measures.

Pacific Power cites data that show that (1) Pacific Power's forced outage rate is declining and is now near the industry average; (2) Pacific Power's planned outage factor and equivalent availability factor, which result from the combination of forced outages and planned outages, are consistently better than the industry average; and (3) the capacity factor (a measure of actual output) shows that Pacific Power's thermal unit performance far exceeds the industry average. Because there is no evidence of "overall imprudence" in Pacific Power's plant operation and maintenance, Pacific Power argues that a prudence disallowance related to its forced outage rates is not warranted.

Because Pacific Power derived its forced outage costs "using (its) most recent four-year historical average, as required by Commission precedent," Pacific Power argues that it has met its burden of proof on this issue. ICNU must explain why the Commission should reverse course and deviate from the application of the four-year average in this case, especially in advance of the generic docket designed to comprehensively review the forced outage rate issue.

Pacific Power states that the purpose of the four-year outage calculation is to accurately forecast forced outages. Adoption of ICNU's proposal would change that purpose and have the Commission look behind the data to determine fault.

Pacific Power argues that ICNU ignores significant improvements in Pacific Power's thermal plant reliability in 2006. Pacific Power finds that omission "particularly inappropriate" since ICNU focused its review "primarily on the 2006 outages.

According to Pacific Power, its capacity factor is 10 percent higher than the industry average. Capacity factors are a measure of actual plant output, which is a function of a generating unit's outages, planned and forced. Pacific Power states that it could not sustain high capacity factors if it did not operate and maintain its thermal plants in a prudent manner.

Pacific Power claims that its customers derive a huge benefit from its high capacity factor. It would be inconsistent for customers to enjoy the benefits of Pacific Power's high capacity factor in rates, and then to lower its forced outage rate and NVPC on the basis of alleged imprudence in plant maintenance.

Regarding the claim that it has reduced planned routine maintenance to the detriment of overall reliability, driving up the costs of its outages, Pacific Power argues that ICNU has not produced any evidence that Pacific Power's outages are more expensive, because its forced outage rate is only slightly higher than the industry average. Planned outages are a significant expense, and the Company makes its best effort to delay forced outages to take the unit offline in off-peak periods.

Further, with regard to the outage attributable to manufacturer defects, Pacific Power argues that ICNU has not shown that Pacific Power was in any way imprudent with respect to that outage, and Pacific Power has shown that it acted reasonably. Pacific Power states that, based on the record, it would be unreasonable to remove that outage from the forced outage rate.

c. ICNU Reply

According to ICNU, "strikingly absent from Pacific Power's brief is any assertion that the outages challenged by ICNU were not caused by imprudence, poor management, personnel or maintenance errors, other avoidable causes or manufacturer defects." ICNU characterizes Pacific Power as relying on a myriad of procedural arguments intended to distract the Commission from actually reviewing the specific outages.

ICNU argues that the Commission should reject Pacific Power's attempt to defer issues to a generic docket. Pacific Power fails to identify any policy issue that requires consideration in a generic docket. There is no precedent that would allow the Company to charge ratepayers costs not shown to be prudent, merely because similar issues may be considered in a future proceeding.

Regarding the recent PGE decision (Order No. 07-015), ICNU states that the Commission was not reviewing a prudency challenge; it was deciding whether to use the utility's own outage rates or generic utility outage rates for setting rates. ICNU notes that the Commission did adjust for PGE's Boardman plant, and claims that ICNU's adjustment in this case "is entirely consistent" with this precedent.

Regarding outages caused by manufacturer error, ICNU argues that Pacific Power has avoided addressing the fundamental issue of responsibility for costs associated with outages caused by manufacturer defects. The Commission adopted a policy in docket UE 88 that the utility should be responsible for costs resulting from outages caused by manufacturer defects.

ICNU argues that Pacific Power's position regarding ICNU's use of Pacific Power's RCA reports is contrary to state law. The RCA reports are Pacific Power's employees' summaries of the reasons for the outages, not remedial measures.

ICNU argues that capacity factors are not relevant to measure prudent operations, because capacity factors are highly continent on the utility's generation mix and overall load, both of which have nothing to do with actual reliability. ICNU cites evidence that Pacific Power's capacity factor is worsening, while the national average is improving.

d. Discussion

As was the case in Order No. 07-015, it is this Commission's policy to use a four-year average of plant outages to calculate the plant forced outage rate for ratemaking purposes. ICNU asks that we adjust the four-year average to exclude outages that it attributes to management/operator error and manufacturer defect.

The four-year average is applied in the TAM proceeding to provide a normalized value for ratemaking purposes. In the context of the TAM proceeding, Pacific Power's evidence to the effect that its capacity factor average is higher than the national average, or that its outage rate is improving, is not conclusive as to the question of what outage rate to assume for estimating Pacific Power's NVPC.

For ratemaking purposes, we do not assume that Pacific Power will be imprudent during the test year. Imprudently incurred costs are not recoverable in rates. Imprudently caused plant outages must be removed from the calculation of the outage rate for TAM purposes.

We do make a distinction between outages caused by management failure (imprudence) and operator error (mistake). We recognize that mistakes are part of the real time operation of a complicated facility in a complicated system. If the rate of operator error were to appear excessive, we might also characterize that result as a management failure. Because of Pacific Power's overall performance, there are no grounds to infer that management failure has contributed to operator error.

Management failure occurs "upstairs," away from the control room, with time for deliberation and consideration of all factors. Management failure constitutes imprudence. Pacific Power's RCA reports are highly probative evidence of the consequences of Pacific Power's management decisions.

We reject Pacific Power's claim that ICNU's reliance on the RCA reports is improper, and will discourage the Company from carefully reviewing and remediating specific outage incidences. The reports were not admitted to support the inference of negligence from the remediation. The reports were used to describe the causes of the events, not the resulting measures.

Reviewing the evidence, we find that the following outages were the result of management failure and should be removed from the calculation of the four-year rolling average:

- Outage directly caused by failure of Pacific Power personnel to install certain equipment properly, and because Pacific Power did not install adequate monitoring equipment.

- Outage caused by senior management's failure to establish a policy to review the effect of changing coal quality, and for failing to fund redesign of reheater and sootblowers.

These outages are identified in Appendix B (confidential).

Regarding the outage attributable to manufacturer's error, Pacific Power does not dispute ICNU's claim that the outage was the result of a design flaw by the manufacturer.

Pacific Power did show that the manufacturer had taken full responsibility for the cost of the repairs.

Where the Company already has held the manufacturer accountable for its defect, application of the policy adopted in the PGE decision would not provide a meaningful incentive and it is not applied in this case. However, given the apparent duration of the resulting outage, we do adopt an adjustment to normalize its effect on rates.

The Company documents show that the anticipated duration of the resulting outage was five to seven weeks. An outage of that duration, no matter what the cause, is anomalous, and raises issues regarding its inclusion in normalized rates. In this case, we find that a 28-day period is a reasonable limit on the length of the outage for the purpose of calculating the TAM adjustment factor. To the extent the actual outage exceeded 28 days, the Company should make an appropriate adjustment to the outage rate used in running the GRID model.

3. *GP Camas Contract Costs*

a. ICNU Position

ICNU states that Pacific Power increased its costs associated with the Georgia Pacific (GP) Camas contract, even though the Company has not actually made any payments to GP. Although the effect on revenue requirement is not great ($118,000), ICNU characterizes this issue as important in limiting the scope of TAM proceedings.

ICNU cites the language in Order No. 05-1050 to the effect that we are concerned that "there is a certain amount of one-sidedness to Pacific Power's annual updates without concomitant adjustments by intervenors and Staff." (p. 21) ICNU argues that Pacific Power's treatment of the GP Camas contract is a "one-sided" increase that would allow the Company to increase NVPC to reflect an "artificial" contract price increase.

ICNU states that because the price for the GP Camas contract has increased, the Company proposes to increase NVPC to reflect this increase. According to ICNU, the contract is complex, however, and there are numerous "offsets" in the contract that reduce the actual costs to the point that Pacific Power will not pay any additional amounts. These contractual offsets are in an "Other Revenue" account that is not included in the TAM.

b. Pacific Power Reply

Pacific Power argues that ICNU's GP Camas contract adjustment should be rejected because it is outside the scope of the TAM proceeding.

According to Pacific Power, pursuant to its GP Camas mill contract, the Company built a steam turbine and is recovering the capacity investment over the twenty-year term of the contract. Pacific Power's NVPC includes the contract costs of energy for the GP Camas unit as a purchased power expense. Pacific Power does not include the credit to Other Revenues for the offset of the capital cost recovery and major maintenance cost recovery amounts.

If it had updated the Other Revenue associated with the GP Camas contract, Pacific Power states that its Other Revenue would decrease by $376,489, increasing the revenue requirement deficiency by the same amount. ICNU's proposal to include both the NVPC and Other Revenue impacts of the update to the GP Camas contract would increase the Company's forecast costs in this proceeding.

c. ICNU Response

ICNU disputes Pacific Power's claim that its GP Camas contract adjustment would increase rates. ICNU argues that the Commission should reject Pacific Power's treatment and not allow any update to the GP Camas contract price unless the Company actually has to pay the increased cost.

d. Discussion

We agree with Pacific Power that ICNU's Camas contract adjustment is outside the scope of the TAM proceeding. We did not intend that the TAM procedure would encompass such factors as contract "offsets" that are better suited to the general rate case, along with other issues relating to capital cost recovery and major maintenance. If we were to entertain such an adjustment in this case, we would have to address Pacific Power's claim that the net result would be an increase.

4. *Hydro Generation Model*

a. ICNU Proposal

ICNU proposes an adjustment for hydro generation of about $450,000.

ICNU argues that Pacific Power's VISTA model used in its direct case overstates the likelihood of extreme hydro conditions. The most significant problem is that the model assumes that all of the hydro resources (even those in separate regions) will be perfectly correlated and will experience the same monthly conditions – drought or flood. ICNU proposes to remedy this problem by computing the mean hydro using the inputs to the VISTA model. ICNU proposes calculating the mean after running the GRID model under wet, median, and dry hydro conditions.

In its rebuttal testimony, Pacific Power revised its model inputs to take out the more extreme conditions. ICNU notes that the procedural schedule did not provide the opportunity to respond to what is essentially a new hydro modeling methodology, or to supplement the record by providing a new GRID study based on mean hydro conditions with updated assumptions. ICNU argues that the Commission should still adopt ICNU's proposed hydro adjustment -- or direct Pacific Power to recompute the GRID model inputs using mean hydro conditions, because they more accurately model expected hydro conditions.

According to ICNU, its hydro adjustment is reasonable because the overall adjustment is similar to result if the GRID model is run under mean hydro conditions (instead of calculating the mean or median, after running the GRID model under wet, median, and dry conditions.)

b. Pacific Power Response

Pacific Power states that its model assumes that generation will not exceed certain extreme levels of "dry" and "wet" conditions, an assumption that conforms to its historical data.

According to Pacific Power, it did include greater extremes and more points across a range of possible outcomes for its VISTA model. However, after reviewing the data, the Company found that the included extremes were greater than any year in the historical record. Consequently, it moved the model to "24 percent and 75 percent" exceedence levels. Most of the actual outcomes will likely fall between the upper and lower boundaries.

Regarding whether to use the mean or the median, Pacific Power states that a calculation using the median rather than the mean better defines the central tendency of hydro generation data, since it is not slanted by extremes on either end. Pacific Power observes that when calculating the mean, values are added and then divided by the total number of values. As a result, an extreme value on either end would sway the average.

When calculating the median, all values above the median have the same probability of occurrence, as do all of the values below the median. By selecting the median, rather than the mean as the measure of central tendency, there is some assurance of stability in the hydro generation distribution.

Pacific Power further argues that ICNU's method uses a flawed linear regression approach and inappropriately averages the generation of three exceedence levels to determine the mean annual hydro generation. Pacific Power argues that one would have to go back and model all the generation levels to determine the average. According to Pacific Power, if ICNU's calculation is corrected to include all the information from ICNU's own analysis, the resulting adjustment is zero.

Pacific Power states that, in the case of a normal distribution, the mean and median would be equal. Because the data sets are small and the distribution is asymmetric, the median provides the best predictive results for future hydro generation.

c. ICNU Reply

ICNU argues that Pacific Power, having acknowledged that its original hydro modeling was flawed, should not be allowed to replicate the same result with an entirely new hydro modeling approach that it proposed for the first time in rebuttal testimony.

d. Discussion

We approve Pacific Power's use of its VISTA model, as modified.

Based on ICNU's direct evidence, Pacific Power revised its model to eliminate the extremes that ICNU found so troubling. There is no evidence that Pacific Power's revised model tends to skew the result in some manner that is more favorable to the Company, and its use is approved.

5. *Station Service Adjustment*

a. ICNU Position

According to ICNU, Pacific Power has proposed a one-sided station service adjustment that inappropriately increases NVPC by about $906,000. Pacific Power's proposal would arbitrarily include a hypothetical transaction in GRID that produces no revenue in the GRID model to reflect alleged station service requirements during plant outages. ICNU argues that this adjustment is inappropriate because it is unverified and contrary to standard industry practice. It would increase outage rates for a loss of generation, while the Company ignores times when generators run above their maximum rated capacity. ICNU states that Pacific Power's adjustment is unique to Pacific Power, and inconsistent with how the industry, as a whole, treats this issue.

b. Pacific Power Response

Pacific Power explains that its service station adjustment is modeled as an addition to retail load to capture the associated system cost of running generation stations when the generation units are off line. Net generation only captures station service when the units are running, thereby excluding station service when the units are not running. Unless a separate load adjustment is made, the costs of station service will not be recovered by the Company.

According to Pacific Power, whether another utility models station service during outages in the same manner is irrelevant, given the unique aspects of its six-state generation system.

Regarding ICNU's claim that the Company ignores the times when its generators are operating at a higher output than assumed in the GRID model, Pacific Power states that the higher operating levels are due to factors such as cooler operating temperatures, higher fuel quality and other circumstances which allow generators to briefly exceed their rated capacities. This limited variation in generation does not belong in normalized ratemaking.

According to Pacific Power, its GRID model produces 45.1 million MWh of coal generation, which exceeds the actual 48-month period ended December 2006, of 44.6 MWh. Pacific Power argues that ICNU failed to respond to Pacific Power's data, and that, because GRID modeling of generation is generous, it is not one-sided, to include in rates, the costs of station service incurred during outages.

c. ICNU Response

ICNU states that Pacific Power has failed to prove that any aspect of its multi-state system is relevant to why it should model this one-sided adjustment that decreases available generation, while ignoring times when its own generators run above their maximum rated capacity.

Regarding Pacific Power's claim that ICNU has ignored its evidence of increased coal generation, ICNU states that the "tiny" increase is not relevant because the GRID model should show an increase in coal generation as Pacific Power's loads increase.

d. Discussion

We approve Pacific Power's inclusion of its station service adjustment. The adjustment reflects real costs that will be incurred during the forecast period.

We decline to adopt ICNU's proposed offset for excess generation. ICNU is comparing model results with actual results. There are many factors that may contribute to such differences other than modeling error.

6. *Cholla 4 Minimum Capacity*

a. ICNU Position

Pacific Power changed the minimum capacity of the Cholla 4 generating unit from 150 MWs to 250 MWs. According to ICNU, Cholla 4 seldom operates in the 250 MW range, and a 150 MW minimum capacity is more realistic.

ICNU states that the minimum capacity of a generation unit is similar to the physical limit of the plant, and is not the regular output of the plant. A generation unit must run at a certain minimum capacity to be efficient and operate properly. ICNU argues that the Commission should set Cholla 4's minimum capacity, based on its actual operating physical limitations.

According to ICNU, the minimum capacity for Cholla 4 is set based on a sodium depletion problem at the unity. After an outage, the unit is generally limited to a minimum of 150 MW capacity, but the sodium depletion problem causes the actual minimum to increase to 250 MW in a period of 60 days. After an outage, the minimum is "reset" and the lower operating minimum becomes effective again. When actual operations are considered, the unit seldom operates in the 250 MW load.

b. Pacific Power Response

Pacific Power states that it has been modeling Cholla 4 minimum operating capacity at 250 MW for several years. Due to transmission constraints, the Company is limited to a minimum generating level of 150 MW. A sodium depletion problem causes the minimum loading of the plant to increase up to 250 MW in a period of 60 days after an outage. After an outage, the sodium depletion issue clears up.

Pacific Power argues that ICNU has failed to realize that, with the removal of hours due to thermal ramping prior to or after an outage, the unit historically has operated below the 250 MW level only three percent of the time over the four years ending December 2006. The Company's modeling has not assumed a worst case scenario.

According to Pacific Power, rerunning the GRID model with the minimum operating level of Cholla 4 at 150 MW results in the operating level of the unit falling below the 250 MW level approximately 14 percent of the hours, which is not consistent with actual operation.

c. ICNU Reply

According to ICNU, Pacific Power's comparison of the three percent operational and 14 percent modeling results is misleading and irrelevant. It is misleading because using the 250 MWs for Cholla 4's minimum capacity in the GRID model results in the unit running at 250 MW 17 percent of the time. "In other words, (Pacific Power's) proposed minimum capacity is just as inconsistent with actual historic operations, and only shows that the GRID model inaccurately runs Cholla 4 at its minimum capacity, regardless of whether the minimum capacity is set at 150 MW or 250 MW."

ICNU argues that the comparison is not relevant because the minimum capacity of a unit is not based on its typical generating output, but on the actual physical limitations of the plant. A minimum capacity for a generation unit does not represent the regular output of the plant. Pacific Power's generation plants need to operate at a certain minimum capacity to be efficient and to operate properly. The Commission should set the minimum capacity of Cholla 4 at 150 MW because it is more reflective of the physical limitation of Cholla 4 during actual operations.

d. Discussion

We find that the 250 MW minimum better represents the historical operation of the plant. We defer to the Company's judgment where it has been running the model using the 250 MW minimum for several years and ICNU has not shown that the results are unreasonable and the sodium depletion issue requires that the Company make special consideration for the plant's operation.

7. *Dave Johnston Maximum Capacity*

a. ICNU Position

Pacific Power proposes to reduce the maximum capacity of the Dave Johnston unit 3 (DJ 3) from 230 MW to 220 MW. ICNU argues that the Commission should set the DJ 3 maximum capacity at 230 MW, because DJ 3 often exceeds the 220 MW “maximum” capacity. The effect of ICNU’s adjustment to the NVPC would be about $783,000.

ICNU notes that Pacific Power argues that the 220 MW maximum capacity is appropriate because state law limits DJ 3’s sulfur emissions. ICNU claims that Pacific Power operates DJ 3 above 220 MWs and has not exceeded the emission limits. According to ICNU, DJ 3 exceeded 220 MWs in approximately 5900 hours over the last four years and in nearly 1800 hours in 2006.

ICNU states that Pacific Power’s argument is based on data that excludes thermal ramping. When Pacific Power overshoots its 220 MW goal, the energy that is produced is available to meet loads or sell on the market.

b. Pacific Power Response

Pacific Power argues there are two problems with ICNU’s proposal. First, the proportion of hours during which the unit’s capacity exceeded 220 MW was actually very small. According to Pacific Power, over the last two years of data, the generation level was above 220 MW on average, approximately five percent of the time. During these hours the level of generation averaged 225 MW or less due to variations in the sulfur content of the coal source. Through the Company’s targeting the SO2 emission limit, the level of generation could be slightly above 220 MW a limited amount of time, but not consistently.

Second, Pacific Power argues that ICNU has missed the significance of the Company’s proposed reduction. DJ 3 is limited by state law to 1.2 lb/MMBtu of SO2 emission, as long as the net input is below 2500 MMBtu/hour. If the unit exceeds the 2500 MMBtu heat input number, a reduction in the SO2 emission rate is triggered to 0.5 lb/MMBTU, which is far more difficult to meet. It is to the benefit of the Company, and its customers, for the SO2 emission rate to remain at 1.2 lb/MMBtu. To meet the 0.5 lb/MMBtu standard the Company would either have to build a scrubber by the end of the test period or find a lower sulfur coal source. Reducing the net generation capacity to 220 MW is important to keep the unit functioning at an acceptable emission rate and avoid unnecessary expenses.

Pacific Power states that DJ 3 has exceeded 220 MW approximately five percent of the time, when ramping is excluded. Those few instances were due to variations in the sulfur content of the coal source and should not be included in normalized conditions.

c. ICNU Response

ICNU argues that DJ 3 operates at above 220 MWs more frequently than Pacific Power suggests, because the data relied on by the Company excludes thermal ramping. The Commission should not change DJ 3's capacity because of the state emission caps. The state emission caps are not relevant because DJ 3, historically, has operated at a capacity above 220 MWs and not exceeded the state emission limits.

d. Discussion

We adopt the Company's 220 MW cap of the DJ 3 capacity as indicative of how the Company plans to operate the unit during the forecast period. Minor variances in actual output are certain but should not be assumed to be one-sided, given the variables that affect actual performance.

C. *CUB*

CUB raised issues regarding the scope of the TAM proceeding. According to CUB, the TAM is intended to be a limited proceeding; Pacific Power is proposing updates beyond what is intended: "the scope of the Company's annual power cost update may be creeping beyond its defined boundaries." Specifically, CUB raised issues regarding GRID modeling changes and the inclusion of wheeling losses.

CUB also raised an issue relating to Pacific Power's accounting for its hydro endowment. According to CUB, Pacific Power did not fully update its fuel and purchased power costs to reflect the effect of increased costs on the value of the hydro endowment.

CUB also expressed concerns regarding the Company's use of internally-generated forward electricity and natural gas price curves in its annual power cost updates. CUB recommended that the Commission require Pacific Power to include at least two independently-produced forward price curves in its final filing.

Regarding the GRID model issues, Pacific Power states that it agrees to formalize a pre-filing review of any future GRID model changes. It also agrees not to include model changes in future TAM filings if Staff, CUB or ICNU objects.

Regarding the hydro endowment, Pacific Power reports that it and CUB have agreed on a process to review how the endowment should be monitored and "potentially updated on a comprehensive basis in response to the TAM and automatic adjustment clauses." Their agreement resolves the endowment issue in this case.

Regarding the matter of the forward price curve benchmarks, Pacific Power agrees to make available its forward price curve, along with the independent third-party forward pricing information that the Company uses, for the one-year test period for the final TAM net power costs update. However, because the Company does not have access to the underlying third-party data or models, the Company will not be able to explain differences of more than five percent between the Company and independent curves.

We find that CUB and Pacific Power have reached a reasonable resolution of the issues raised by CUB that were not otherwise satisfied. The result of their agreement will be an enhanced TAM procedure.

V. CONCLUSION

Pacific Power should update its NVPC to reflect the changes adopted in this decision to establish its TAM NVPC for calendar year 2008.

FINDINGS OF FACT

1. Pacific Power's GRID model systematically fails to capture nearly 75 percent of all short-term sales and purchase transactions.

2. The volume of omitted sales nearly equals the volume of omitted purchases.

3. Staff assumes that the close correlation between purchase and sale volumes proves that Pacific Power actively trades energy for profit in the wholesale market.

4. Staff recommends an adjustment to Pacific Power's NVPC, based on the difference between the Company's average purchase and sale prices.

5. Staff's method mixes actual results and normalized forecasts.

6. About 87 percent of Pacific Power's short term transactions are for balancing purposes.

7. Pacific Power's Oregon allocated margin on its arbitrage and tracking activities not shown to be included in GRID is $0.8 million annually.

8. The amount of NVPC in rates approved in UE 170 was about $215.

9. The UE 179 Stipulation provided for an increase in the NVPC of $10 million.

10. The amount of NVPC in Pacific Power's rates is $225 million.

11. A four-year average of outage rates is a reasonable measure of plant performance.

12. Some of the outages are attributable to management failure.

13. Some of the outages are attributable to operator error.

14. One of the outages is attributable to manufacturer’s defect.

15. The outage attributable to manufacturer’s defect was an anomaly.

16. The Company’s NVPC includes the contract cost for energy for its GP Camas contract.

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17. The Company’s NVPC does not include the credit to Other Revenues for the offset of the capital cost recovery and major maintenance cost recovery amounts.

19. Pacific Power modified its GRID model to less extreme levels of hydro generation.

20. The station service adjustment captures the associated system cost of running generation stations when the generation units are off line.

21. Pacific Power has modeled its Cholla 4 unit minimum capacity at 250 MW for several years.

22. The 250 MW Cholla 4 minimum capacity reflects a sodium depletion problem.

23. Pacific Power proposes to reduce the maximum capacity of DJ 3 from 230 MW to 220 MW.

24. Pacific Power’s adjustment to the DJ 3 maximum capacity reflects limits on sulfur emissions.

25. GRID model changes raise issues regarding the scope of TAM proceedings.

26. CUB claimed that Pacific Power did not fully update its fuel and purchased power costs to reflect the effect of increased costs on the value of its hydro adjustment.

27. CUB expressed concerns regarding Pacific Power’s use of internally-generated forward price curves.

CONCLUSIONS OF LAW

1. In its next TAM filing Pacific Power should include $0.8 million for margins associated with its short-term trading activities.

2. Pacific Power should use $225 million as the amount of NVPC in current rates for calculating its TAM revenue requirement change.

3. The four-year average should be adjusted to exclude outages caused by management failure.

4. Two outages are removed from the forced outage rate calculation due to management failure.

5. In this case the four-year average should be adjusted for the anomalous outage due to manufacturer's defect to a period of 28 days.

6. Contract offsets, such as capital cost recovery and major maintenance, are best suited for a general rate case.

7. Company's estimate of hydro availability is reasonable.

8. Station service adjustment costs should be incorporated into the TAM.

9. Pacific Power reasonably uses the 250 MW minimum for modeling Cholla 4.

10. Pacific Power's proposal to reduce the DJ 3 maximum from 230 MW to 220 MW is reasonable.

11. The agreement between Pacific Power and CUB, regarding GRID model changes in TAM proceedings, is reasonable.

12. The agreement between Pacific Power and CUB, regarding the hydro endowment, is reasonable.

13. The agreement between Pacific Power and CUB, regarding the use of forward price curve benchmarks in TAM calculations, is reasonable.

ORDER

IT IS ORDERED that Pacific Power shall update its net variable power costs to reflect the changes adopted in this decision to establish its TAM NVPC for calendar year 2008.

Made, entered, and effective OCT 17 2007.

Lee Beyer
Chairman

John Savage
Commissioner

COMMISSIONER BAUM WAS UNAVAILABLE FOR SIGNATURE

Ray Baum
Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order by filing a petition for review with the Court of Appeals in compliance with ORS 183.480-183.484.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UE 179

In the Matter of PACIFIC POWER & LIGHT (d/b/a PacifiCorp) Request for a General Rate Increase in the Company's Oregon Annual Revenues	**STIPULATION**

This Stipulation is entered into for the purpose of resolving all issues among the parties to this Stipulation related to PacifiCorp's requested revenue requirement increase in this docket.

PARTIES

1. The initial parties to this Stipulation are PacifiCorp (or the "Company"), Staff of the Public Utility Commission of Oregon ("Staff"), the Citizens' Utility Board ("CUB"), the Industrial Customers of Northwest Utilities ("ICNU"), Fred Meyer Food Stores and Quality Food Centers, Divisions of Kroger Co. ("Kroger"), City of Portland, Klamath Water Users Association ("KWUA") and League of Oregon Cities ("League") (together "the Parties"). This Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of the Stipulation.

BACKGROUND

2. On February 23, 2006, PacifiCorp filed revised tariff schedules for Oregon that would result in a base price increase of approximately $112 million or 13.2 percent. PacifiCorp based its filing on a 2007 calendar year test period. PacifiCorp filed a Net Variable Power Cost ("NVPC") update (consisting of a Transition Adjustment Mechanism ("TAM") update and Supplemental Testimony), which increased its requested revenue requirement by approximately $6.7 million for a total of $118.7 million.

3. Pursuant to Administrative Law Judge Kirkpatrick's Prehearing Conference Memorandum, the Parties commenced settlement conferences on June 14-16, 2006. These settlement conferences continued on June 21, 23 and July 10, 24 and 27, 2006. The settlement conferences were noticed and all parties were invited to participate.

4. As a result of the settlement conferences, the Parties have reached a comprehensive settlement in this case. The net effect of this Stipulation reduces PacifiCorp's proposed increase in test period revenue requirement to a maximum of $43 million, which would result in an overall rate increase of approximately 5 percent. PacifiCorp's revenue requirement increase will include two separate components. First, there is a non-NVPC increase of $33 million. Second, there is a NVPC/TAM increase for 2007 that is capped at $10 million. The NVPC/TAM increase for 2007 may be less than $10 million. The effective date of these new rates is January 1, 2007, which reflects a short extension of the statutory suspension period applicable to this case. Exhibit A to this Stipulation contains the calculation that will be used to determine the NVPC increase in this case. Exhibit B to this Stipulation shows the revenue requirement at the maximum $43 million level, reflecting the maximum NVPC/TAM increase for 2007 possible under this Stipulation. Exhibit C to this Stipulation shows the estimated rate spread, assuming a total $43 million increase. The final, overall rate increase may be less than $43 million.

AGREEMENT

5. The Parties agree to submit this Stipulation to the Commission and request that the Commission approve the Stipulation as presented. The Parties agree that the following

adjustments, and the revenue requirement levels resulting from their application, are fair, just, sufficient and reasonable:

a. Non-NVPC Rates: The Parties agree to a revenue requirement increase of $33 million, which represents a settlement of all issues in this case, except NVPC/TAM, which is addressed in paragraph 5(b). Regardless of the overall level of rate increase derived from the NVPC/TAM procedure explained in section 5(b), PacifiCorp shall not increase its non-NVPC rates in this case by more than $33 million.

b. NVPC/TAM: In addition to the non-NVPC rate increase, the Parties agree to a NVPC/TAM rate increase for 2007 capped at a maximum of $10 million. This increase will be calculated using the following steps:

(i) Begin with PacifiCorp's proposed UE 179 total Company NVPC of $889.4 million.

(ii) Subtract $50 million, producing an adjusted NVPC of $839.4 million. This $50 million adjustment is comprised (for settlement purposes only) of the following adjustments: Cool Keeper $1.3 million; Foote Creek Wind $.8 million; Planned outages $1.3 million; Desert Power QF $13.4 million; Ancillary Benefits $4.1 million; and Other $29.1 million. No other modeling changes will be made to GRID (PacifiCorp's NVPC model) and applied in this case, unless agreed to by the Parties. The Parties agree that this procedure will ensure that the NVPC/TAM increase for 2007 will not exceed a maximum of $10 million allocated to Oregon. The Parties reserve their rights to challenge changes to the GRID model or data input changes other than those agreed to in this Stipulation in the TAM updates.

(iii) Subtract PacifiCorp's current NVPC of $796.5 million from the adjusted UE 179 NVPC of $839.4 million to determine the total NVPC-related increase before 2007 TAM updates and before application of the $10 million cap. This increase to $839.4 million would result in a $42.9 million NVPC increase. Regardless of the final TAM amount, the total Company NVPC for 2007 will be capped at $834.4 million, and the NVPC increase will be capped at $37.9 million. Exhibit A contains the calculation used to derive these amounts.

(iv) Regardless of the final level of NVPC/TAM rates for 2007, the Parties agree that the Company may not increase non-NVPC rates by any amount above $33 million in this case to make up for an NVPC increase of less than $10 million allocated to Oregon.

(v) The ultimate level of the NVPC/TAM increase for 2007 will be based upon the difference between the total Company NVPC in rates as approved in UE 170 and the total Company NVPC in rates after completion of the TAM process in this case. The amount of the final NVPC/TAM increase for 2007 is not yet in the record in this proceeding, but the Parties agree that the total Company NVPC/TAM limitation agreed to in this Stipulation will ensure that the NVPC/TAM increase for 2007 is not more than $10 million allocated to Oregon.

(vi) PacifiCorp will apply three TAM updates to its NVPC in the fall of 2006 before the proposed effective date for rates in this case. The first update is scheduled for October 9, 2006 for new or revised wheeling, fuel and wholesale sales and purchases contracts and known and measurable changes for wholesale sales, purchase power, wheeling, natural gas, coal and the Leaning Juniper wind project as of September 30, 2006. The second update is scheduled for November 1, 2006 and will include the most recent forward price curve for electricity and natural gas, setting indicative prices for calculating the direct access transition adjustment. The final update is on November 14, 2006, again including only the most recent forward price curve for electricity and natural gas prices, setting the final direct access transition adjustment. No other updates to NVPC applicable to 2007 are permissible under this Stipulation. The Parties have not reviewed these yet to be filed TAM updates; therefore, the Parties reserve the right to challenge any of these TAM updates on grounds other than those covered by this subsection and by subsection 5(b)(ii), including the fact that they include imprudent new or revised contracts, inaccurate information, or inappropriate GRID model changes or data inputs, or are otherwise inconsistent with this Stipulation or the law.

(vii) PacifiCorp will compare its adjusted NVPC after the three fall 2006 updates and conduct the same calculation set forth in subsection 5(b)(iii) above to determine the final NVPC/TAM increase for 2007 in this case. PacifiCorp will include its actual NVPC results for 2007 in rates, not to exceed an Oregon allocated increase of $10 million for rates to be effective January 1, 2007.

c. Rate Change Effective Date: The Parties agree that the rate changes as specified in this Stipulation should go into effect on January 1, 2007. The Company agrees to waive the current tariff suspension date in UE 179 of December 24, 2006 to January 1, 2007.

d. Cost of Capital: The Parties agree that the overall rate of return ("ROR") should be set at 8.16 percent, which also settles all issues associated with cost of capital (*e.g.,* issuance costs). The Parties further agree that, for all Oregon regulation purposes, until such time as the Commission issues a general rate order subsequent to UE 179, PacifiCorp will use the weighted cost of capital set at 8.16 percent ROR. The Parties do not agree on the individual capital components that result in the ROR of 8.16 percent. Without accepting the individual capital components, the Parties have derived the ROR of 8.16 percent, and for Oregon regulation purposes will assume the components, as specified in the table below.

Component	% of Capital	Cost	Weighted Cost
Debt	49.00%	6.32%	3.10%
Preferred	1.00%	6.30%	0.06%
Common	50.00%	10.00%	5.00%
Total	100.00%		8.16%

e. Pensions: The Parties agree that this Stipulation will permit the Company to recover its full FAS 87 pension expense. The Parties have not reached an agreement regarding whether the FAS 87 pension expense criteria used by the actuary included in PacifiCorp's original filing is appropriate. This agreement is non-precedential and is not binding upon the Parties for any future PacifiCorp rate case.

f. Taxes: The Parties agree on the tax expense levels contained in the revenue requirement model attached as Exhibit B, which are calculated on a stand-alone basis. For CUB, ICNU, City of Portland and KWUA, this agreement is expressly non-precedential and predicated on the fact that the AR 499 rulemaking is not yet completed and the SB 408 automatic adjustment clause can function to recover any over collection in tax expense resulting from this case. CUB, ICNU, City of Portland and KWUA reserve their right to argue in future PacifiCorp rate proceedings that the Commission should adjust tax expense to reflect the projected level of taxes to be paid under the Commission's SB 408 rules.

g. Rate Case Stay-Out: PacifiCorp agrees that it will not file a new general rate case (defined as a general rate revision under OAR 860-022-0017(1)) in Oregon before September 1,

2007. This stay-out precludes PacifiCorp from seeking recovery of capital costs, including any deferred recovery, of Leaning Juniper or any other new generation resource in Oregon before September 1, 2007. PacifiCorp's filing in 2007 for its 2008 TAM is expressly excluded from this stay-out provision.

h. Rate Spread: The Parties agree to the rate spread set forth in Exhibit C, subject to adjustments as necessary to match the final 2007 NVPC-related rate increase in this case. As a general matter, the rate spread for the non-NVPC rate increase is largely based upon equal percentage increases to all rate groups, with a few adjustments, and the NVPC portion of the rate increase is spread only to the energy component of rates.

i. City of Portland and League Issues: PacifiCorp agrees to work with the City of Portland and the League on mutually agreeable rules for restoration priorities for PacifiCorp's Oregon service territory, and file tariffs with the Commission by January 1, 2007 reflecting these rules. PacifiCorp agrees to extend Schedule 781, the direct access shopping incentive schedule through December 31, 2009, with a shopping credit in 2007 of 5 mills, in 2008 of 4 mills and in 2009 of 3 mills. To facilitate the City of Portland's ability to participate in PGE's direct access election window beginning in November 2006 for its street-lighting customers, PacifiCorp also agrees to work with Portland General Electric Company ("PGE") to ensure that no direct access barriers exist for City of Portland street lighting customers covered by the 1977 contract between PacifiCorp and PGE. The City of Portland acknowledges the need for a reciprocal commitment from PGE for effective implementation of this agreement.

j. Direct Access Opt-Out Tariff: PacifiCorp and ICNU agree to support the adoption of PacifiCorp's Schedule 295, Advice No. 05-015, which was filed on October 14,

2005. Schedule 295 creates a long-term opt-out offering for direct access customers for the November 2006 direct access enrollment window. Staff agrees to work with PacifiCorp and ICNU to develop a long-term opt-out tariff acceptable to PacifiCorp, ICNU and Staff. Staff agrees to bring this filing before the Commission no later than October 24, 2006. PacifiCorp agrees to file and support revised rate schedule 295, which is attached as Exhibit D to this Stipulation.

6. The Parties to this Stipulation agree that it resolves all issues in this case. The Parties agree that this Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Stipulation shall not be admissible as evidence in this or any other proceeding.

7. This Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Stipulation at the hearing, and recommend that the Commission issue an order adopting the settlements contained herein.

8. If this Stipulation is challenged by any other party to this proceeding, the Parties agree that they will continue to support the Commission's adoption of the terms of this Stipulation. The Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Stipulation.

9. The Parties have negotiated this Stipulation as an integrated document. If the Commission rejects all or any material portion of this Stipulation or imposes additional material conditions in approving this Stipulation, any Party disadvantaged by such action shall have the

rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

10. By entering into this Stipulation, no Party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other Party in arriving at the terms of this Stipulation, other than those specifically identified in the body of this Stipulation. No Party shall be deemed to have agreed that any provision of this Stipulation is appropriate for resolving issues in any other proceeding, except as specifically identified in Section 5 of this Stipulation.

11. This Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Stipulation is entered into by each party on the date entered below such Party's signature.

Signature page follows

Exhibit A

Transition Adjustment Mechanism (TAM)
Net Variable Power Cost (NVPC) Cap and Increase calculation
Millions $

Total Company UE 170 NVPC		$796.5
Oregon TAM Cap increase UE-179	10	
Allocation factor '/1	26.40%	
Total company Cap increase	37.9	37.9
Total company NVPC CAP		$834.4

/1 weighted 50% SG / 50%SE (26.6279+27.1727)/2

CONFIDENTIAL APPENDIX B IS AVAILABLE PURSUANT TO THE TERMS OF THE PROTECTIVE ORDER (ORDER NO. 07-134) ISSUED IN THIS PROCEEDING.