UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Pacific Gas and Electric Company	)	Docket Nos. ER98-495-000
	)	ER98-1614-000
	)	ER98-2145-000,
		and ER99-3603-000

JOINT REPLY BRIEF OF
THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION,
PACIFIC GAS AND ELECTRIC COMPANY,
SAN DIEGO GAS & ELECTRIC COMPANY,
AND SOUTHERN CALIFORNIA EDISON COMPANY

To: Hon. H. Peter Young
Presiding Administrative Law Judge

Pursuant to the procedural schedule in this case, the California Independent System Operator Corporation ("ISO"), Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), and Southern California Edison Company ("Edison") (together, "Signatories"), hereby provide this Joint Reply Brief. The principal purpose of this Joint Reply Brief is to respond in opposition to the initial brief filed by the applicants, Southern Energy Delta, L.L.C., and Southern Energy Potrero, L.L.C. (collectively, the "Southern Parties"). This Joint Reply Brief also comments on the initial brief filed by the Commission Trial Staff ("Staff").

I. OVERVIEW

It is not disputed that the reliability-must run contracts between the ISO and the Southern Parties ("RMR Agreements") are needed to mitigate the local market power of the Southern Parties' generating units, at times when these units are needed for local area reliability. As the Southern Parties have acknowledged in their initial brief: "The cost-based rates provided for in the RMR Agreements are intended to mitigate the generation unit owner's potential market power in those limited instances where it may possess locational market power." (Initial Brief of Southern Parties ("Southern I.B.") at 5.) By agreeing to honor their RMR obligations, the Southern Parties have been able to obtain Commission authorization to charge market-based rates for, and hence earn potentially unlimited profits from, sales of energy and ancillary services at their three power plants.

Fundamentally, the disagreement in this case boils down to a single point: Should the Fixed Option Payment be set at a level that makes the RMR plant owner whole for the costs incurred to respond to calls from the ISO when the unit is not making market sales of energy or ancillary services, as the Buyers' Coalition has proposed? Or, as the Southern Parties have proposed, should the Fixed Option Payment be set at a level that significantly increases the RMR owner's profits, relative to what the owner would enjoy if it were a pure merchant plant operator, without local market power and the associated contractual restrictions and obligations required to mitigate that local market power?

While the Buyers' Coalition and Staff propose various forms of an incentive payment, their basic position – articulated by an impressive array of distinguished economists – is the same: the owner should be made no better off, and no worse off, by virtue of the market power mitigation provisions of the RMR Agreements than the owner would be as a pure merchant plant operator without locational market power. The Southern Parties, in contrast, have proposed a very large contribution to their sunk costs via the Fixed Option Payment (a weighted average of 76.1 percent, according to a calculation in Staff's Initial Brief). (Initial Brief of Commission Staff ("Staff I.B.") at 27.) The Southern Parties thus seek a substantial increase in the profits they would enjoy as a pure merchant plant operator who does not have local market power that must be mitigated in order to receive market-based pricing authority. They base this demand on three key assertions: (1) that the RMR Agreement is a form of "capacity" contract; (2) that they purchased the subject power plants in "reliance" on "assurances" by PG&E of some sunk cost recovery; and (3) that any departure from sunk cost recovery would be inconsistent with the April 2 Stipulation and the RMR Agreements themselves. As discussed below, and as explained more fully in the Signatories' Joint Opening Brief, all three of these assertions are demonstrably erroneous.

The correct principle is that the RMR owner should be made "no better off, and no worse off" as a consequence of its local market power and the RMR Agreements that are used to mitigate that market power.

II. SUMMARY DESCRIPTION OF THE VARIOUS PARTIES' POSITIONS

The positions of the parties, as set forth in their testimony and initial briefs, can be summarized in table form (with record and initial brief citations as shown):

		CPUC		ISO, PG&E, SDG&E, SCE and EOB		FERC Staff		Southern Parties	
	AFRR	FOPF	FOP	FOPF	FOP	FOPF	FOP	FOPF	FOP
Contra Costa 6	$19,578,429	3%	$494,351	5%	$913,279	11%	$2,139,370	77%	$15,075,390
Contra Costa 7	$21,292,124	2%	$521,677	5%	$1,050,701	11%	$2,335,053	77%	$16,394,935
Pittsburg 1	$2,298,798	9%	$200,300	16%	$367,693	11%	$252,194	72%	$1,655,135
Pittsburg 2	$3,748,873	6%	$214,853	13%	$500,147	11%	$411,278	72%	$2,699,189
Pittsburg 3	$3,087,977	4%	$134,792	6%	$191,072	11%	$338,773	72%	$2,223,343
Pittsburg 4	$3,138,936	4%	$136,407	4%	$134,813	11%	$344,363	72%	$2,260,034
Pittsburg 5	$17,658,097	1%	$258,530	3%	$584,630	11%	$1,937,218	72%	$12,713,830
Pittsburg 6	$20,818,762	2%	$498,890	5%	$1,025,551	11%	$2,283,965	72%	$14,989,509
Pittsburg 7	$48,691,087	1%	$611,138	3%	$1,285,995	11%	$5,416,467	72%	$35,057,583
Delta Plants	$140,313,083		$3,070,938		$6,053,881		$15,458,681		$103,068,947
Potrero 3	$17,053,729	13%	$2,142,558	24%	$4,012,680	23%	$3,847,931	97%	$16,542,117
Potrero 4	$183,831	24%	$43,311	58%	$107,265	11%	$20,587	97%	$178,316
Potrero 5	$216,316	49%	$105,935	88%	$189,372	11%	$24,206	97%	$209,827
Potrero 6	$206,612	28%	$58,360	69%	$141,791	11%	$23,001	97%	$200,414
Potrero Total	$17,660,488		$2,350,164		$4,451,108		$3,915,725		$17,130,673
SOUTHERN TOTAL	$157,973,571		$5,421,102		$10,504,989		$19,374,406		$120,199,621

CPUC amounts based on CPUC's theoretical approach, as set forth in Ex. CPUC-1, using numbers from PG&E exhibits. Gross Incremental Cost w/o adder = Incremental Cost from Ex. PGE-9, Columns A and B, + Ex. PGE-21(rev), Column H, except Potrero 3, where incremental cost-based compensation is less than the Net-of Market going-forward cost from Ex. PGE-5

ISO, PG&E, SDG&E and SCE position from Joint Opening Brief, at 8

EOB position from Opening Brief of the California Electricity Oversight Board, at 4-5 and 21. Note, the EOB there stated that it does "not oppose" the adder proposal; the figures shown above, in the column including EOB, incorporate the Adder.

FERC Staff position from Staff I.B., Attachment.

Southern position from Southern I.B. at 13, and from Ex. SOU-6. Unfortunately, in neither its testimony nor its Initial Brief has Southern provided a unit-by-unit breakdown of its Fixed Option Payment proposals. The figures shown above were derived by multiplying the FOPFs in Ex. SOU-6 by the AFRR for each unit.

III. DISCUSSION OF THE RESERVED ISSUES

A. What Is The Appropriate Level of the Fixed Option Payment Under Each Revised RMR Rate Schedule?

As the foregoing table illustrates, the Fixed Option Payment ("FOP") levels proposed by the Southern Parties are much higher than all the other proposals in this case. Under the Southern Parties' proposal, more than 75 percent of each unit's sunk costs and fixed operation and maintenance ("O&M") costs would be paid by the ISO under the RMR Agreements, yet the Southern Parties also would keep all revenues from market sales of energy and ancillary services. As such, the Southern Parties' proposal would actually be much more lucrative for the RMR owner than the old "A" or "B" forms of agreement. Staff aptly noted that, by the end of the hearing in this case, these high FOP levels, "looked a bit like orphans, with no one to support them who had any first hand knowledge of Southern's operations in California." (Staff I.B. at 29.) The Joint Opening Brief has already discussed all of the Southern Parties' principal arguments. In this Joint Reply Brief, the Signatories will respond only as necessary to flesh out the key points and any remaining issues.

The Signatories also will take this opportunity to clarify their proposed incentive payment, or "adder," since there appears to have been some confusion about this issue in some of the initial briefs.

1. Response To The Southern Parties' Arguments

a) In Arguing That The RMR Agreement Should Be Treated As A Form Of "Capacity" Contract, The Southern Parties Have Failed To Address The Key Issue, Namely, The Fact That The RMR Agreements Do Not Impound Economic Value.

In their initial brief, the Southern Parties emphasized at the outset that "the service provided by the Southern Parties to the ISO pursuant to the RMR Agreements is plainly a capacity product." (Southern I.B. at 8, *citing* testimony of Dr. Madian and Mr. Lamkin.) They have argued that the terms of the RMR Agreements "show that RMR service is a sale of capacity, as distinct from a sale of energy." (*Id*.)

The Southern Parties have alleged that the rebuttal testimony of the various witnesses testifying for the Buyers' Coalition, who pointed out a critical distinction between the RMR Agreements and traditional capacity contracts, "elevate[s] form over substance . . . ." (Southern I.B. at 10.) In the rebuttal testimony to which the Southern Parties refer (which is summarized in the Joint Opening Brief at 11-13), the Buyers' Coalition witnesses explained that, under a capacity contract, the seller loses the right to sell its output when the output is called upon by the buyer, whereas under the RMR Agreements, the plant owner always retains that right.

The Southern Parties selectively emphasize only certain facial similarities between a capacity contract and the RMR Agreements, while ignoring the economic substance of these fundamentally different types of agreements. Thus, it is actually the Southern Parties who have "elevated form over substance." The attributes of the RMR Agreements upon which the Southern Parties base their analogy to capacity contracts are the "availability" requirement, the fact that the RMR Agreements are specific to particular units at particular locations, and the fact that they include what the Southern Parties refer to as "capacity-based penalties." (Southern I.B. at 8-9.) Although some capacity contracts may have some of the same attributes as the RMR Agreements, the key distinction between the two remains. The seller under a capacity contract does not retain any rights to its output at times when the buyer demands it, whereas the RMR owner under the RMR Agreements retains that economic value at all times. The RMR Agreements merely prevent the owner from withholding a unit's capacity from the market at times when the unit is needed for local reliability. As the Southern Parties admitted in the September 1999 Lender Memorandum (Ex. PGE-30, p. 56), the RMR Agreements do not "impound market value from the generators." The RMR owner should not be compensated as if they did, which is what the Southern Parties have proposed.

It is revealing that the Southern Parties in their initial brief chose to ignore completely the Lender Memorandum (Ex. PGE-30), in which the Southern Parties themselves characterized the RMR Agreements in much the same way as the Buyers' Coalition witnesses did here. (See Joint Opening Brief at 13-14 (quoting the pertinent portion of the Lender Memorandum, and explaining its significance).) Apparently, the Southern Parties have elected to wait for their reply brief to discuss this document, at which point the other parties will not have a further opportunity to respond.

At the hearing, the Southern Parties' two witnesses who testified about the Lender Memorandum (Dr. Madian and Mr. Lamkin) offered conflicting explanations.
Dr. Madian testified that he had not seen the Lender Memorandum until it was produced

in discovery the day before the hearing began. He said he believed the Lender Memorandum's statement that the RMR Agreements do not give the ISO "the right to impound the market value from these units" was not a true statement. (Tr. at 683:19-23.) He went on to characterize the Lender Memorandum as a "sales document," saying that "there is something in the world of sales which is called puffery . . . ." (Tr. at 687:24 - 688:2.)

The next day, Mr. Lamkin testified. He was the corporate officer responsible for creating the pertinent portions of the Lender Memorandum before it was sent to potential lenders. Mr. Lamkin disputed Dr. Madian's testimony about the Lender Memorandum, saying that his view was "quite a bit different than what [Dr. Madian] expressed or hypothesized yesterday." (Tr. at 766:16-17.) Mr. Lamkin offered a new explanation. He said the Lender Memorandum's statement that RMR Agreements do not give the ISO "the right to impound the market value from these units" should have been qualified by the additional phrase "except in certain real-time situations." That phrase actually appears at the beginning of the next sentence, and, according to Mr. Lamkin, was misplaced in the final preparation of the Lender Memorandum. Mr. Lamkin testified that, "with that grammatical fix," the document "makes perfect sense." (Tr. at 767:24 - 768:1.)

Ultimately neither of these witnesses offered any explanation that could reconcile the Lender Memorandum's representations regarding the RMR Agreements with the Southern Parties' testimony here that the RMR Agreements are a form of "capacity" contract. In fact, as discussed in the Joint Opening Brief at 13-14, the Lender

Memorandum describes the RMR Agreements in a way that is not only accurate, but also entirely consistent with the testimony of the various Buyers' Coalition witnesses.

b) The Southern Parties Have Not Articulated A Persuasive Rationale For Dr. Madian's Lopsided "Allocation" Proposal.

The Southern Parties have contended that the Fixed Option Payment should be determined by an "allocation" of the fixed costs, including sunk costs, of the subject power plants between the ISO and market operations, as proposed by Dr. Madian. (Southern I.B. at 11-18.) They have cited several Commission cases that they argue support Dr. Madian's allocation methods. (*Id.* at 17 (*citing TECO Power Services Corp.*, 53 FERC ¶ 61,202 (1990)), 18, n. 9 (*citing Consumers Energy Co.*, 85 FERC ¶ 61,121 (1998), *Commonwealth Edison Co.*, 82 FERC ¶ 61,317 (1998), and *Delmarva Power & Light Co.*, 76 FERC ¶ 61,331 (1996), *reh'g dismissed*, 80 FERC ¶ 61,330 (1997)).)

In the Joint Opening Brief at 21-28, the Signatories have explained the many conceptual and computational flaws in Dr. Madian's allocation methods. Simply stated, Dr. Madian's proposal to allocate more than 75 percent of the fixed costs of the three power plants to the ISO under the RMR Agreements is grossly disproportionate to the dominant use of these plants as merchants in the competitive energy and ancillary services markets. It cannot be reconciled with the fact that the Southern Parties, under the current, Commission-approved, form of RMR Agreements, are permitted to keep all the revenues they earn from such market sales.

The cases cited by the Southern Parties do not support their position. Indeed, the Commission's decisions in these cases only serve to confirm that the allocations proposed by Dr. Madian are demonstrably unjust and unreasonable.

In the first case cited by the Southern Parties, *TECO Power Services Corp.*, the Commission approved an allocation of fixed costs of a power plant (the proposed new Hardee Power Station) between two firm sales customers: Tampa Electric Company, TECO Power's 100 percent-owned utility affiliate, and Seminole Electric Power Cooperative, Inc., an arms'-length, third-party customer. The Commission there approved an allocation of 60 percent of the fixed costs of the Hardee plant to Seminole, and 40 percent to Tampa Electric.

Interestingly, the Commission in *TECO Power Services Corp.* found that an allocation based on "relative energy deliveries . . . may be a reasonable basis to allocate this resource . . . ." 53 FERC at 61,812. The Commission, however, did not approve the allocation on that basis, because the applicants there "provided no data or testimony to support their 20-year projections of expected energy deliveries." *Id.* In the present case, of course, PG&E witness Weingart proposed an allocation based on energy deliveries (the Megawatt Hour ("MWh") allocator), but unlike the applicants in *TECO Power Services Corp.*, he had a sound empirical basis for his proposal, *viz.*, data from the Southern Parties' units. Essentially, Mr. Weingart used the proportion of ISO usage to total metered generation to suggest an alternative to Dr. Madian's allocators. (*See* Exhibit PGE-20.) His proposed allocator is supported by the Commission's statement in

TECO Power Services Corp. that "relative energy use may be a reasonable basis to allocate this resource."

More importantly, the Commission in *TECO Power Services Corp.* also specifically required that any revenues earned from market sales of energy from the Hardee plant, at times when the output was not called upon by the two firm customers, had to be credited to the two firm customers in the same proportions as their fixed cost responsibility (*i.e.*, 60/40). Indeed, the Commission specifically *rejected* a plan to credit some of these market revenues to TECO Power Services, the utility's marketing affiliate, finding that "Power Services' retention of any revenue credits would appear to result in equity returns in excess of its costs and therefore be unjust and unreasonable." 53 FERC at 61,813. Accordingly, the Commission ordered the applicants "to revise the revenue credit provisions to increase Seminole's share to 60 percent, Tampa Electric's share to 40 percent, and exclude Power Services." (*Id*).

In this case, the Southern Parties propose to allocate in excess of 75 percent of their fixed costs (AFRR) to the ISO under the RMR Agreements, *while keeping 100 percent of the revenues they earn in market-based sales of energy and ancillary services*. Plainly, their reliance on *TECO Power Services Corp.* is misplaced.

The other three cases cited by the Southern Parties likewise do not support the Southern Parties' proposal in this case. In each of the cited cases, the Commission granted market-based pricing authority for certain energy sales by traditional public utilities, but conditioned its authorization on the utility's commitment not to engage in market-based sales, but rather to continue cost-of-service-based sales, to customers in generation or transmission markets in which the utility still had market power. *See Consumers Energy*, 85 FERC at 61,447; *Commonwealth Edison*, 82 FERC at 62,249 n. 4 (citing prior cases); *Delmarva*, 76 FERC at 62,582. The Southern Parties point out that "[i]n none of these cases . . . has the Commission required the seller to revise its rates for cost-based services to strip out 'sunk costs.'" (Southern I.B. at 18.) On that basis, the Southern Parties contend that their "proposed allocation method is wholly consistent with this approach and should be adopted in this proceeding." (*Id.* (footnote omitted).)

The cited cases are not at all analogous to the present situation. In each of those cases, the Commission allowed a vertically-integrated electric utility to make market-based sales of energy, but only in circumstances where it did not have market power. Any sales by the utility to its captive customers, meanwhile, remained under traditional, cost-of-service regulation, and indeed each of the subject utilities was specifically prohibited from engaging in sales at market-based rates to such captive customers. *See, e.g.*, *Delmarva*, 76 FERC at 62,582.

The Southern Parties seem to be suggesting that, when they respond to ISO dispatch notices, they are engaged in "sales of RMR services" to the ISO at cost-based rates, and that this activity is analogous to the energy sales the utilities made to their captive customers at cost-based rates in the foregoing cases. Because the Commission in those cases did not require any adjustment to the cost-based rates to "strip out sunk costs," the Southern Parties assert that they, too, should be able to recoup sunk costs through the ISO's Fixed Option Payment under the RMR Agreements.

The flaw in this analogy is that it mischaracterizes the nature of the Southern Parties' obligations under the RMR Agreement. Unlike a service involving the sale of energy or ancillary services, the RMR Agreement merely requires that the owner respond to ISO dispatch notices at times when the owner is otherwise not in the market. It ensures that the owner cannot withhold its unit from the market and thereby exercise its locational market power. Nothing in the RMR Agreement prohibits the owner from engaging in market-based sales, and, to the limited extent the RMR dispatch notices may interfere with certain sales, the Buyers Coalition proposes to fully compensate the owner. The RMR obligations are triggered only when the owner, for whatever reason, chooses not to engage in a market-based sale of energy or ancillary services. There is no legitimate comparison between this market-power mitigation device and the Commission's prior decisions granting market-based pricing authority to vertically integrated utilities that remained subject to cost-of-service-based pricing for sales to captive customers. The fact that the Commission continues to allow sunk costs to be recovered in sales of energy to captive customers is not a precedent for allowing the Southern Parties to allocate sunk costs to the ISO under the RMR Agreements. The Southern Parties should seek to recover their sunk costs through market-based sales of energy and ancillary services, not from the ISO.

c) The April 1999 Stipulation Did Not Create A Right To, Or Any Reasonable Expectation Of, Sunk Cost Recovery For Condition 1 RMR Units.

The Southern Parties have argued that excluding so-called "sunk costs" from the Fixed Option Payment would be inconsistent with the April 2 Stipulation. (Southern I.B. at 22-24.) Rather than point to any express provisions in either the Stipulation itself or in the RMR Agreement, however, the Southern Parties merely have alleged that an incremental cost method of compensation is "inherently at odds with the April Stipulation." (Southern I.B. at 22.)

The Signatories already have addressed this argument in the Joint Opening Brief, at 46. The only new angle in the Southern Parties' initial brief is their argument that, prior to the April 2 Stipulation, none of the parties now advocating the incremental cost method of compensation had publicly advocated that method before. (Southern I.B. at 25.) This allegation proves nothing about the meaning of the April 2 Stipulation. It was that Stipulation which established the new form of RMR Agreement, and which eliminated the revenue crediting requirement for market units. The parties were not required, nor did they have the opportunity, to state their position on the proper pricing for Condition 1 units until later, when their testimony was filed in the instant phase of these proceedings. It is of no significance that the parties did not publicly articulate their positions earlier. As explained in the Joint Opening Brief at 46, the April 2 Stipulation left open, in very broad language, the issue of "the appropriate level of the Fixed Option Payment under each revised RMR rate schedule." This language cannot reasonably be interpreted to limit the debate in such a way as to require that sunk costs be included.

The Southern Parties also have argued that the net incremental cost method of compensation "effectively reads the stipulated revenue requirements settlement out of the April Settlement." (Southern I.B. at 23.) As explained in the Joint Opening Brief at 46, the fact that the April 2 Stipulation contained a settled "Annual Fixed Revenue Requirement" ("AFRR") for each RMR unit does not mean that sunk costs must be included in the Fixed Option Payment. It was necessary to state an AFRR for all units in the event they elected Condition 2 status. The AFRR also served as a ceiling for fixed cost reimbursement for Condition 1 units, since any amounts in excess of book value would violate the Commission's orders in *Duke Energy Moss Landing LLC*, 83 FERC ¶ 61,318, *reh'g denied*, 86 FERC ¶ 61,227 (1999). The inclusion of a stated AFRR in the April 2 Stipulation cannot reasonably be interpreted to mean that the Stipulation somehow guarantees some level of sunk cost recovery in the Fixed Option Payment.

Even farther afield is the following argument in the Southern Parties' Initial Brief:

> The starting point for the net incremental cost approach, the notion that RMR services should provide for *no contribution to fixed costs,* is inherently at odds with the April Stipulation. Nowhere in the April Stipulation, or in the revised form of contract included as part of that settlement, do the parties state that RMR service is to be provided at zero profit to the generation owners. Rather the opposite is clearly the case, and *recovery of fixed costs* is plainly a key component of the April Stipulation.

(Southern I.B. at 23. Emphasis added.) This is not an accurate description of the Buyers' Coalition proposal. Under the net incremental cost method of compensation that the Buyers Coalition has proposed, the RMR owner would be paid for *all incremental fixed costs* attributable to the RMR Agreements. (*See, e.g.*, Ex. PGE-3 (Weingart-Direct) at 17:4-5 ("The FOP for an RMR facility should compensate the owner *for the incremental fixed cost* of meeting its RMR obligations . . . .") (emphasis added).) The Southern Parties are wrong in suggesting that, by excluding *sunk costs*, and by limiting the Fixed Option Payment to going-forward costs only, the Buyers' Coalition somehow has eliminated *fixed costs* from the calculation of the Fixed Option Payment. This is simply an incorrect reading of the Buyers' Coalition's plainly stated position.

d) The Southern Parties' Allegation That They Purchased The Three Subject Power Plants In "Reliance" On PG&E "Assurances" Of Sunk Cost Recovery Through The RMR Agreements Is Neither Credible Nor Pertinent To The Issues In This Case.

The Southern Parties have claimed that they had "reasonable commercial expectations," when they purchased the subject power plants, that the RMR agreements, rather than market sales of energy and ancillary services, would provide them with significant sunk cost recovery. The Southern Parties have accused PG&E and its aligned parties of "a full 180-degree turn from their contemplated approach when the Southern Parties agreed to buy PG&E's generation facilities and to assume the RMR Agreements from PG&E." (Southern I.B. at 32-33.) They have concluded that "[t]his proceeding should not devolve into a forum for these parties to utilize the Commission and its administrative procedures to reopen and re-trade the terms of the prior divestiture transaction." (*Id.* at 33.)

The Joint Opening Brief has explained (at 28) the complete lack of any record basis for the Southern Parties' allegations regarding any expectation of sunk cost recovery from the RMR agreements in addition to whatever recovery they may achieve through unregulated market sales of energy and ancillary services. Without repeating those points, it is sufficient to note here that the Southern Parties made an extremely weak showing of reliance. They introduced no contemporaneous documents showing that they had any such reliance, and they provided no testimony by any percipient witnesses. (Mr. Lamkin, the only company witness to testify, began employment in 1999, *after* the Southern Parties made their bid for the power plants.) The Southern Parties essentially staked their entire reliance claim on an innocuous, one-line reference to "revenues from the Master Must-Run Agreement with the ISO" in the PG&E Offering Memorandum. (Ex. SOU-18.) There is nothing in the Buyers' Coalition proposal in this case that is the least bit inconsistent with a representation that the Southern Parties will earn "revenues from [the RMR Agreements]," as the Offering Memorandum stated. The question here is what *level* of compensation the Southern Parties should be paid. As to that question, the Offering Memorandum did not make the representations asserted by the Southern Parties.

In its landmark Order No. 888, [1/] which required a significant restructuring of wholesale power markets, the Commission "reaffirm[ed] that a utility seeking to recover stranded costs must demonstrate that it had a reasonable expectation of continuing to serve a customer." FERC Stats. & Regs., Regs. Preambles at 31,831. Among other things, the Commission there concluded that "[w]hether a utility had a reasonable expectation of continuing to serve a customer, including whether there is sufficient evidence to rebut the presumption that no such expectation existed beyond the notice provisions in a contract, will depend on the facts of each case." (*Id*).

In arguing that they had a "reasonable expectation" of sunk cost recovery from RMR Agreements when they agreed to purchase the subject power plants in late 1998, the Southern Parties in effect are seeking treatment similar to that the Commission accorded

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1 / Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (1996), FERC Stats. & Regs. ¶ 31,036 (1996), order on reh'g, Order No. 888-A, 62 Fed. Reg. 12,274 (1997), FERC Stats. & Regs. ¶ 31,048 (1997), order on reh'g, Order No. 888-B, 81 FERC ¶ 61,248 (1997), order on reh'g, Order No. 888-C, 82 FERC ¶ 61,046 (1998).

vertically integrated utilities in Order No. 888. The Southern Parties, however, have not offered any explanation as to *why* they should deserve any special treatment based on their alleged subjective expectations, and it is difficult to see how such treatment could be justified. The Commission's task here is to set the price for a set of agreements designed to mitigate market power in the newly restructured, competitive market place. These kinds of agreements did not exist in the former, bundled utility environment. Moreover, the need for such market power mitigation is likely to arise in virtually every regional transmission organization that is created. This is, therefore, an important case of first impression that may guide the Commission's treatment of similar issues throughout the nation. The Commission should adhere to sound economic principles, not the alleged subjective expectations of any one party, in deciding the reserved issues in this case.

In Order No. 888 itself, the Commission also ruled that its allowance for showings of "reasonable expectation" of continued service under pre-existing service agreements would not extend to new service contracts executed after the direction of the new rules became clear. As the Commission stated there:

> We reaffirm our preliminary determination that future wholesale requirements contracts should explicitly address the mutual obligations of the seller and the buyer, including the seller's obligation to continue to serve the buyer, if any, and the buyer's obligation, if any, if it changes suppliers. As we indicated in the Supplemental Stranded Cost [Notice of Proposed Rulemaking], now that utilities have been placed on explicit notice that the risk of losing customers through increased wholesale competition must be addressed through contractual means only, they must address stranded cost issues when negotiating new contracts or be held strictly accountable for the failure to do so.
>
> We accordingly will allow recovery of wholesale stranded costs associated with any new requirements contract (executed after July 11,

> 1994) only if explicit stranded cost provisions are contained in the contract. By "explicit stranded cost provision" (for contracts executed after July 11, 1994) we mean a provision that identifies the specific amount of stranded cost liability of the customer(s) and a specific method for calculating the stranded cost charge or rate.

FERC Stats. & Regs., Regs. Preambles at 31,805-806.

In this case, the Southern Parties can point to no explicit contractual language in existence in late 1998 that would establish any sort of "reasonable expectation" of sunk cost recovery under the RMR Agreements. The most they can point to is the fact that the then-existing "B" form of agreement included full fixed cost recovery; that contract, however, also included a requirement that all market revenues had to be credited against this payment up to its full amount. Moreover, the Commission had never approved that form of agreement, and indeed the Commission had expressed concerns about the level of fixed cost recovery it provided. *See Pacific Gas and Electric Co., et al.,* 81 FERC ¶ 61,122 at 61,558 (1997). [2/] In these circumstances, the Southern Parties cannot credibly claim to have had any sort of firm contractual assurance of sunk cost recovery when they bid on these plants in November 1998.

But even putting aside the question whether the Southern Parties should be able to make a "reasonable expectation" argument in the absence of contractual language, their reliance showing is inadequate in any event. It may be helpful in this regard to review prior decisions in which applicants have claimed a "reasonable expectation" of continued service to a customer in order to qualify for stranded cost recovery. Two of those decisions illustrate the kind of showing an applicant must make to establish a "reasonable expectation." *See Puget Sound Power & Light Co.*, 78 FERC ¶ 63,001 at 65,005-013 (1996) (initial decision of Judge Zimmet), and *City of Alma, Michigan*, 88 FERC ¶ 63,002 at 65,017 (1999) (initial decision of Judge Dowd). When contrasted to the showings the applicant utilities made in the two foregoing cases, the reliance claim by the Southern Parties in this case pales by comparison. Reduced to its essence, the Southern Parties' contention is that they expected to get sunk cost recovery based on their reliance on a form of RMR Agreement that everyone knew was in flux, that had never been approved by the

[2/] In the October 30, 1997, Order, the Commission also noted: "The ISO states that it would periodically review the need for Must-Run contracts for specific units and in general. The ISO proposes to replace initial agreements in the 'near term' with a more competitive process to maintain system reliability in a least-cost manner." 81 FERC at 61,555. It also noted the ISO's commitment to revise the "B" form of agreement within one year, and the ISO's position that "fixed cost recovery is a *reasonable temporary measure*" pending such revisions. *Id.* at 61,556.

Commission, and also based on a one-line description of "revenues from the Master Must-Run Agreement with the ISO" in the PG&E Offering Memorandum (Ex. SOU-18) (see Joint Opening Brief at 28).

To briefly summarize, the Southern Parties have not shown why their alleged subjective expectation regarding sunk cost recovery from the ISO in late 1998, when they committed to purchase the subject power plants, should be given any consideration in this case, and in any event they simply have not made a credible showing that they had any such "reasonable expectation" in the first place.

e) The Presiding Judge Should Not Be Persuaded By The Southern Parties' Exaggerated Contentions That The Net Incremental Cost Method Of Compensation Is "Confiscatory," "Punitive," Or Would Produce "Zero Profit."

The Southern Parties in their initial brief have repeatedly stated that the "net incremental cost" method of compensation proposed by witnesses for the Buyers' Coalition would yield "zero profit" for the Southern Parties. (Southern I.B. at 22, 25, 26, 28, 32, 35). They have stated, for example, that the Buyers' Coalition's position is based on the notion that "the Southern Parties should provide reliability service at zero profit because other revenue opportunities are available in the competitive energy markets." (*Id.* at 35.) They also contend that Professor Joskow advocated that the RMR Agreements be priced in such a way as to render them a "zero profit arrangement." (*Id.* at 18-19 (*citing* Ex. SCE-2 (Joskow-Direct) at 59:5-6).) Elsewhere, the Southern Parties have contended that the net incremental cost method is "confiscatory." (Southern I.B. at 20.) They also have claimed that the net incremental cost method of compensation will yield a "punitive result." (*Id.* at 25.)

These statements fundamentally misrepresent the net incremental cost method supported by the Buyers' Coalition. To begin with, Professor Joskow did not advocate that RMR Agreements be priced so as to render them a "zero profit arrangement," as the Southern Parties incorrectly stated in their initial brief. In the quoted portion of his testimony, Dr. Joskow was discussing his proposal to include an incentive payment, or "adder," in the Fixed Option Payment. Professor Joskow, however, did not advocate that the Fixed Option Payments be set so as to ensure "zero profit" for the Southern parties. On the contrary, he proposed – and the Signatories have adopted his proposal – that "it would be a good idea to add a modest incentive payment to the Fixed Option Payment for each unit." (*Id.* at 59:15-16.) It is inaccurate to describe Professor Joskow's testimony as advocating a "zero profit" Fixed Option Payment. Indeed, Professor Joskow expressly stated that "[o]ne could reasonably take the view that there is a financial benefit to their entering into the RMR agreements since these agreements are the ticket they required to get market-based pricing authority and the financial benefits that go with it." (*Id.* at 59:6-9.)

Nor would the Fixed Option Payment levels proposed by the Signatories (as depicted in the table on page 4, *supra*) yield anything close to a "zero profit" – or "confiscatory" – result, as the Southern Parties have contended. The net incremental cost method is fully compensatory of all costs incurred by the Southern Parties that are not otherwise paid by the ISO under the RMR Agreements. The "adder," in turn, ensures a comfortable margin above this level. Finally, of course, the RMR owners are free to earn unbounded profits from market sales of energy and ancillary services, profits that the Southern Parties have conveniently ignored in their initial brief.

In sum, the incremental cost method of compensation is not "punitive" in any sense, and, as discussed in the Joint Opening Brief at 44-46, it also does not result in any "disallowance" of costs, as the Southern Parties have asserted.

f) The Southern Parties Have Not Identified Or Quantified Additional Opportunity Costs, Nor Have They Shown Why The ISO Should Pay Any "Locational Rent" Premium.

Part of the Southern Parties' attack on the net incremental cost method of compensation is that it "requires a regulatory determination of the opportunity costs and benefits associated with providing RMR service." (Southern I.B. at 42) They have claimed that "[t]he task is difficult even in theory, and will prove extremely contentious in practice." (*Id.*) They have further asserted that determining "the opportunity cost associated with the loss of locational rents under the RMR Agreements would be similarly complex." (*Id*). The Southern Parties also have argued that PG&E witness Weingart, who sponsored the Buyers' Coalition's calculations of opportunity costs, "simply ignore[d] every kind of opportunity cost under the RMR Agreements other than those associated with an RMR unit's inability to decrement output to take advantage of opportunities in the real-time market." (*Id.*)

The Commission should not be persuaded by these efforts by the Southern Parties to suggest that there exist large, as yet unidentified and difficult-to-quantify opportunity costs. In their initial testimony, PG&E witnesses Weingart and Pace made a comprehensive effort to identify and quantify all opportunity costs. Further, Dr. Pace specifically invited the Southern Parties to identify and quantify any opportunity costs he might have overlooked. (*See* Ex. PGE-1 (Pace-Direct) at 9:14-16.) In their rebuttal testimony, the Southern Parties failed to even identify, let alone quantify, any additional opportunity costs. In his own rebuttal testimony, meanwhile, Mr. Weingart responded to Dr. Madian's assessment that the RMR Agreements resulted in "takings" of economic value. Mr. Weingart concluded that, although there was some validity to Dr. Madian's "takings" argument, the true value of the "takings" Dr. Madian identified was only approximately $1.5 million per year, roughly one-tenth the amount Dr. Madian had calculated. (*See* Ex. PGE-21 (revised).) (See discussion in Joint Opening Brief at 43.) In the Joint Opening Brief, the proposed FOP was adjusted to include this $1.5 million, even though the Southern Parties had not suggested it be specifically included in the FOP calculation.

The record thus shows that the Buyers' Coalition has reasonably identified and quantified the Southern Parties' opportunity costs, and that no legitimate, significant sources of opportunity costs have been overlooked. The Southern Parties' belated effort, in their initial brief, to suggest that there exist large, unidentified, unquantified opportunity costs is ultimately unpersuasive. Furthermore, the "adder" the Signatories have proposed would provide reasonable assurance that the Southern Parties will be paid for, among other things, any opportunity costs that were not otherwise covered.

The Southern Parties also contend that the net incremental cost method of compensation deprives them of "locational rents" (as opposed to earnings due to the exercise of market power) that would be permitted in a competitive market, assuming one could exist for RMR service." (Southern I.B. at 47.) They have argued that, "[b]y invoking a pricing system for RMR service that ignores this market design failure, the net incremental cost proposal exacerbates California's RMR problem and sends inappropriate price signals to potential new generators and transmission owners." (*Id*.)

The simple answer to this line of argument is that California may elect a market redesign that allows generators to capture scarcity rents in constrained locations. Indeed, in response to the Commissions Order regarding Amendment 23, the ISO and stakeholders in California are in the process of considering alternative *comprehensive* reforms to the current congestion management system. *California Independent Operator System Corp.* 90 FERC ¶ 61,006. Cabrillo is free to participate as a stakeholder in that process. Building such rents into the Fixed Option Payments under the RMR Agreements today is not the right solution, however. Doing so would represent a piecemeal rather than a comprehensive reform to the ISO's congestion management system, contrary to the spirit of the Commission's order regarding Amendment 23, and would provide generators with local market power with the opportunity to earn locational scarcity rents that are not presently available in California to generators *without* local power. Moreover, adding such scarcity rents to the fixed option payment now could lead to double-recovery in the event such market redesign is undertaken and includes the incorporation of scarcity payments for all generators (as the Southern Parties among others have advocated). Nor have the Southern Parties, as the applicants in this case, sustained their burden of quantifying such scarcity rents and distinguishing them from a premium that could be extracted through an exercise of market power. Absent such proof, the Commission is not in a position to make an upward adjustment to the Fixed Option Payment levels in order to allow the RMR owner an opportunity to capture so-called scarcity rents.

g) The Southern Parties Have Provided A Misleading Picture Of Their Expected Market Revenues.

In their initial brief, the Southern Parties have contended that the "expected levels of market revenues" as contained in the forecasts of certain of the Buyers' Coalition witnesses will cause the Southern Parties to experience a shortfall compared to what they would be paid if they operated their units under Condition 2 of the RMR Agreements (which would pay them their full AFRR, but would deny them market opportunities). (*See* Southern I.B. at 36-42.)

This argument mischaracterizes the Buyers' Coalition testimony. As described in greater detail in the Joint Opening Brief at 35-42, the forecasts of market revenues sponsored by the Buyers' Coalition, in particular by ISO witness Theaker, provided a *conservative* estimate of market revenues. They were done for the limited purpose of screening out any Condition 1 units that may not cover going-forward costs. No Buyers' Coalition witness "testified that the Southern Parties are not expected to recover their revenue requirements through market sales alone," as the Southern Parties have alleged. (Southern I.B. at 36.)

The Southern Parties' initial brief also fails to account for the Southern Parties' own internal revenue forecasts, which the Southern Parties provided in discovery only reluctantly, on the very eve of hearings. Because those revenue forecasts, at Southern

Parties' request, are in the sealed portion of the record pursuant to a Protective Order, and because they are discussed in a sealed portion of the Joint Opening Brief, the Signatories are reluctant to create yet another sealed document by describing them again here. Suffice it to say that it is disingenuous for the Southern Parties to cry poverty, as they have done throughout their initial brief, without at least *some* acknowledgment of their own internal forecasts of market revenues.

h) There Clearly Is No Merit To The Argument That The Commission's *Duke Energy Moss Landing* Orders, Which Summarily Rejected An "Acquisition Premium," Established Some Entitlement To Sunk Cost Recovery In RMR Agreements.

In *Duke Energy Moss Landing LLC*, 83 FERC ¶ 61,318, *reh'g denied*, 86 FERC ¶ 61,227 (1999), the Commission summarily rejected part of a proposed RMR rate schedule through which the owner would have recouped through RMR rates the premium the owner paid above book value when it purchased the units in question. The Commission set for hearing the remainder of the applicant's RMR rate schedules.

The Southern Parties have argued that the Commission's rulings in *Duke Energy Moss Landing* case "did not adopt the position advocated by the Buyers Coalition in this case and require Duke to look exclusively to the market for recovery of all of the fixed costs associated with RMR generation." (Southern I.B. at 30.) The argument overlooks the fact that the Commission's original order in *Duke Energy Moss Landing* was merely a suspension order that set Duke's rate filing for evidentiary hearings. Although the Commission found one part of Duke's filing – the acquisition premium – to be so objectionable as to warrant summary rejection, the Commission by this action certainly did not signal that the remainder of the filing was acceptable. On the contrary, the suspension order contained the usual disclaimer:

> Our preliminary review of the proposed rates indicates that they have not been shown to be just and reasonable, and may be unjust, unreasonable, unduly discriminatory or preferential, or otherwise unlawful. Accordingly, we will accept the proposed rates for filing, suspend them for a nominal period, to become effective subject to refund, and set them for hearing.

Duke Energy Moss Landing, 83 FERC at 62,306.

In fact, the present case is now at the point where the *Duke* case would have been, had Duke Energy not settled. Testimony has been filed, the evidentiary hearing has been held, and the record now is closed. Nothing in the *Duke* suspension order remotely suggests that an owner of RMR units should expect to recoup any part of its sunk costs in RMR rates. This is the very issue that now must be decided.

The Southern Parties also have argued, based on the forecasts produced by Mr. Theaker's "net market revenues" model, that the Southern Parties cannot expect to recoup their acquisition premium in the competitive markets. (Southern I.B. at 30.) They contend that, "[w]ith such a large shortfall, it is likely to be impossible for the Southern Parties to earn any contribution to recovery of their acquisition premium from the market, in contravention of the Commission's order in *Moss Landing*." (*Id*. at 30-31.) In making this argument, the Southern Parties once again conveniently have ignored their own internal revenue forecasts. But their argument misconstrues in any event the Commission's decision in *Duke Energy Moss Landing*. The Commission there obviously did not give any *assurance* that the RMR owner would be able to recoup its acquisition premium from market activities. It left open the prospect that an owner might simply have paid too much for a given plant, or might have paid a premium based on factors other than the value of the current generating units, such as the site value of the property for additional development. Even if the Southern Parties paid more for these plants than the plants can be expected to earn in market sales of energy and ancillary services (putting aside the site value of the land), nothing in *Duke Energy Moss Landing* orders even remotely suggests that the Southern Parties should be able to look to the ISO and to captive ratepayers to make up the difference.

i) Comparisons To The Settlements Other California RMR Owners Have Reached Are Improper, Nor Are They Persuasive In Any Event.

PG&E, like the Southern Parties, also owns several power plants that are subject to RMR obligations. The Southern Parties have alleged that "the FOP factors offered by PG&E and the Buyers Coalition are markedly different from those currently in effect for PG&E's own RMR units," and that there will be "dramatically disparate financial impacts of the proposed FOPs on the Southern Parties' facilities as compared to the application of the higher FOPs applicable to PG&E's RMR units." (Southern I.B. at 33, 34.)

As the Commission is well aware, the RMR rates currently in effect for the PG&E units were the result of an arms-length settlement between PG&E and the parties representing the interests of consumers: the ISO, the CPUC, the EOB, and the Staff. The Commission approved that settlement earlier this year. *Pacific Gas and Electric Company*, 90 FERC ¶ 61,023 (2000). Under Rule 602 of the Commission's Rules of Practice and Procedure, it is not proper for the Southern Parties, as the applicants in the present, contested proceeding, to attempt to justify their rate proposals by engaging in comparisons of their opponents' proposals here with the rates of other applicants in Commission-approved settlements. Allowing such comparisons would have a dampening effect on the willingness of parties to negotiate settlements, for fear their compromises will be used against them later, and would contradict the Commission's policy of encouraging candid settlement discussions. *See El Paso Natural Gas Co.*, 83 FERC ¶ 61,300 at 62,243-244 (1998) (*citing Columbia Gas Transmission Corp.*, 26 FERC ¶ 61,324 at 61,699 (1984)).

But the comparisons the Southern Parties seek to make are unpersuasive in any event. The Southern Parties attempt to compare one PG&E plant (the Humboldt Power Plant) with the Southern Parties' plants. But they introduced no evidence at hearings that would allow a meaningful comparison of, for example, the heat rates and other operating characteristics of these plants, or the extent to which their respective capital investments have been depreciated. (*See* Tr. at 625:23-25 (Weingart) (noting that the Humboldt units were built in 1949, are not very economic, and are not expected to earn much in the way of market revenues).) Thus, the various numerical comparisons the Southern Parties have advanced in their initial brief, at 34, between the Humboldt plant and their own units are meaningless at best, and very possibly misleading. They should be given no weight in these proceedings.

2. Clarification Regarding The Particular "Adder" Endorsed By The Signatories, And Response To Staff's Critique Of That Approach

In its Initial Brief, Staff has stated that the "adder" supported by witnesses for various of the Buyers Coalition parties, which also was endorsed by the Signatories in the Joint Opening Brief, is derived by taking ten percent of the RMR owner's *variable* costs and adding that amount to the Fixed Option Payment. (Staff I.B. at 20-21.) Staff also criticizes the Buyer's Coalition's approach on the ground that it allegedly would yield only a *de minimis* incentive payment in comparison to the AFRR-based adder Staff has proposed. (*Id*. at 24.)

It appears Staff may have misunderstood the Buyer's Coalition's proposal. That proposal was *not* limited to a percentage of variable costs, but also included a percentage of the fixed costs included in the Fixed Option Payment. As the Signatories explained in the Joint Opening Brief, the Buyers' Coalition proposal calls for "an additional payment equal to 10 percent of net incremental RMR-related costs (including fixed costs as well as a forecast of variable costs) . . . " Nor does this method yield a *de minimis* incentive payment. On the contrary, of the total $10.5 million Fixed Option Payment the Signatories have proposed (see Joint Opening Brief at 8, Col. D), approximately $5.4 million of that amount consists of the incentive payments. The virtue of this approach, moreover, is that it ties the incentive payments to the incremental costs an RMR unit incurs to respond to "out-of-market" calls from the ISO.

For its part, Staff has proposed that an incentive payment be calculated simply by multiplying the AFRR for each unit by 10 percent. The problem with Staff's approach is that it is likely to reward the wrong generators because it is based on AFRR, a number that bears no relationship (or a perverse relationship) to the operating economics of the RMR units. For example, picture a relatively new RMR unit with a relatively low heat rate and a relatively high sunk cost (because it is new). For illustrative purposes, assume this unit can make profitable market sales during 99 percent of the hours when it is also needed for local reliability. Under Staff's proposal, this generator would get an additional 10 percent of AFRR for no good reason. Under the Buyers' Coalition's proposal, this RMR unit would indeed receive a small incentive payment since the RMR obligations impose no cost burden on it. Consider a second generator that is an old cycling unit with a high heat rate and a low AFRR (because it is old and substantially depreciated). This unit is only in the market when prices are very high and must be called frequently by the ISO when it is not in the market. Under Staff's proposal, this unit would get 10 percent of a very small AFRR (*i.e.*, a very small incentive payment), despite the fact that it is primarily providing service to support the reliability of the network *and* the fact that its net market revenues (and forecast net incremental costs) are very sensitive to market conditions and forecasting errors. Under the Buyers' Coalition proposal, this second RMR unit would receive a much more significant incentive payment because the costs it incurs to respond to calls from the ISO are much larger since it is rarely economical for this unit to make market sales.

The only virtue of the FERC staff's approach is simplicity. However, in the end, it is better to measure the right number with some uncertainty than to measure the wrong number precisely. Accordingly, the Commission should adopt the incentive payment proposed by Professor Joskow and endorsed by the Signatories in the Joint Opening Brief (at 47), rather than the incentive payment proposed by Staff.

B. What Shall Be The Means Of Determining The Percentage Applied To The Approved Cost Of A Capital Item To Yield The Surcharge Payment For That Item?;

And

C. What Shall Be The Means Of Determining The Percentage Applied To The Approved Cost Of A Repair To Yield The ISO's Repair Share For That Repair?

There are only two points of disagreement with respect to these issues. *First*, the Southern Parties have challenged PG&E's position that the "default" percentage to be paid by the ISO for Capital Additions and Repairs should be zero in the case of economic units. (Southern I.B. at 48-49.) However, the "default" percentage here is less important than providing flexibility for the parties to negotiate case-specific ISO percentages for particular Capital Additions and Repairs. As Mr. Weingart explained:

> My proposal allows for flexibility in determining the percentages when one or both parties believe the FOP Factor percentage is not appropriate for the item in question. Mr. Felak's approach is much more rigid and allows a change in the ISO's percentage share only when the RMR owner can prove the sole reason for the Capital Item or Repair was its necessity for RMR service, with absolutely no efficiency or other market benefits for the owner.

(Ex. PGE-18 at 28:15-21)

Second, in arguing that the Fixed Option Payment Percentage should be the default percentage for the ISO's share of Capital Additions and Repairs, the Southern Parties have insisted that the FOP should include all fixed costs, including sunk costs. (Southern I.B. at 49.) The inappropriateness of including sunk costs in the Fixed Option Payment has been discussed fully above, and in the Joint Opening Brief. If the Fixed Option Payment is to be used as the default percentage for Capital Additions and Repairs, it should be based solely on the unit owner's net incremental cost, with an appropriate adder or incentive payment. It should not include any sunk costs.

IV. CONCLUSION

The Commission should adopt the recommendations of the Buyers' Coalition in this proceeding.

Respectfully submitted,

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Dated: April 28, 2000

CERTIFICATE OF SERVICE

I hereby certify that I have this day caused the foregoing document to be served on those parties on the restricted service list compiled by the Presiding Administrative Law Judge in these proceedings.

Dated at Washington, D.C., this 28th day of April, 2000.

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