UNITED STATES OF AMERICA 91 FERC ¶ 63,008
FEDERAL ENERGY REGULATORY COMMISSION

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

INITIAL DECISION

(Issued June 7, 2000)

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H. Peter Young, Presiding Administrative Law Judge

TABLE OF CONTENTS

A. STIPULATED PROCEDURAL HISTORY/FACTUAL BACKGROUND

The parties submitted the following Joint Stipulation of the Procedural History and Factual Background, which is hereby adopted for purposes of this Initial Decision:

This Joint Stipulation of the Procedural History and Factual Background in these proceedings is jointly sponsored by all the active parties in these proceedings who are listed in the footnote below.[1] By means of this Joint Stipulation, the parties will be able to avoid repetitious descriptions of the procedural and factual background in their individual post-hearing briefs. At issue in this case are certain aspects of the rates the Southern Parties charge the ISO for "reliability must-run" ("RMR") service at three power plants in the San Francisco Bay Area – the Contra Costa, Pittsburg, and Potrero plants – which the Southern Parties purchased from PG&E in April 1999.

I. Introduction

This case arose as part of the restructuring of the electric power industry in California. The new industry structure began on April 1, 1998, when both the ISO and the California Power Exchange ("PX") commenced their respective operations. The ISO operates an extensive electric transmission system, consisting of portions of the electric systems of PG&E, SCE, and SDG&E, while the PX operates several forward markets for electric energy. Both entities were formed pursuant to California's electric industry restructuring legislation (California Assembly Bill 1890, enacted in August 1996).[2]

As discussed in greater detail below, this case originally concerned the rates, terms and conditions for RMR Agreements that give the ISO the right to call on numerous generating plants in California when needed for transmission system reliability, including but not limited to those now operated by the Southern Parties. These so-called RMR owners provide services to the ISO under RMR rate schedules and contracts on file with this Commission, and the ISO compensates them for such services. Under the terms of its Commission-approved Tariff, the ISO passes through to the "Responsible Utilities" (namely, the transmission owners) the cost of RMR Agreements in each utility's service area. It is not disputed that this Commission has jurisdiction over the services the generators provide under RMR Agreements, as well as over their wholesale sales of electric energy in the open market and their sales of ancillary services to the ISO. Initially, most of the RMR generating plants were owned by the investor-owned utilities in California, but since then the utilities have sold most of these plants to other generating companies.

II. Description of the RMR Agreements

The integrated electric systems in California and elsewhere, historically, were designed to minimize system cost (and thus the price to customers). In some cases, this meant using generating units to perform tasks which are essentially transmission system functions. Because of this design feature, some generating units “must run” at certain times in order to ensure system reliability. This remains true even in deregulated markets. When transmission constraints limit imports into certain areas (known as “load pockets”), generation located near load is needed to serve local customers. In other cases, generation must be operated to protect the system from voltage collapse, instability, and thermal overloading. If local generation were not operating in such instances, for example because it was not already scheduled to run for the market, the ISO would risk equipment damage or would need to shed customer loads.

a. The Need for RMR Agreements.

The RMR Agreements at issue in this proceeding are between the Southern Parties and the ISO. At certain times, due to transmission constraints, one or more of the Southern Parties' units may be required to deliver energy to avoid a local reliability problem. Pursuant to these agreements, the ISO is authorized to dispatch one or more of the Southern Parties' generation units on an as-needed basis to deliver energy in order to meet local reliability needs at a price to be determined, in part, in this proceeding.[3] The RMR Agreements also enable the ISO to dispatch the units to provide ancillary services such as Regulation, Spinning Reserve, and Voltage Support when needed on a regional or even statewide basis.

When a unit is dispatched by the ISO in such circumstances, it is needed to deliver energy or provide voltage support regardless of price. Consequently, those unit owners at that time have local market power (*i.e.*, could potentially charge a high price in the absence of the RMR Agreement). Such local market power extends only to those times when the units are required to serve a reliability function. In response to such circumstances, the RMR Agreements were created to prevent the generation owners from taking advantage of location-specific market power.

The Southern Parties are engaged in sales of energy and ancillary services in one or more of the competitive, bid-based markets available to market participants in California (including the PX), or through bilateral contracts. In most instances where the Southern Parties are engaged in market transactions at times when a unit is needed to deliver energy for reliability purposes, the market transaction will (in whole or in part) satisfy the ISO's reliability needs and the ISO will not need to change the unit's output to deliver energy in accordance with the RMR Agreement, although this is not always the case. The ISO and the other parties refer to this aspect of the RMR Agreements as the "Market-First" principle.

b. Operation of the RMR Agreements

RMR unit owners who operate as market participants in energy and ancillary services markets can elect a form of RMR Agreement known as "Condition 1." Unit owners operating under Condition 1 are paid a combination of several different rates. First, they are paid for their variable costs and for prepaid start-ups. These payments, detailed in Schedules C and D of the RMR Agreement (Exh. JT-2), are not at issue in this proceeding. Second, they are paid a Monthly Option Payment which, as detailed in Schedule B of the RMR Agreement, is the sum of the Monthly Availability Payment and Monthly Surcharge Payment, less any Monthly Nonperformance Penalty.

An RMR unit's "Fixed Option Payment" ("FOP") (whose level for the Southern Parties' Condition 1 RMR units is the primary remaining issue) is the maximum allowable Monthly Availability Payment summed over the twelve months of the year. This term does not appear in the RMR Contract itself, only in the settlement in this docket dated April 2, 1999 ("April 2 Stipulation") (Exh. JT-1). Participants also propose FOPs in the form of Fixed Option Payment Factors ("FOPFs"). The FOPF (a percentage specified as an interim value in Schedule B under the April 2 Stipulation) can be calculated by dividing the Annual Fixed Revenue Requirement ("AFRR") (a figure also specified in Schedule B) by the FOP. If an RMR unit is available for ISO dispatch up to its Maximum Net Dependable Capacity for all of its Target Available Hours for the year (*see* Schedule A and Table B-5), its FOP will equal the sum of its Monthly Availability Payments. Under the currently-effective RMR Agreements, the owner of a Condition 1 unit retains all revenues earned in the competitive markets for energy and ancillary services; none of these revenues are credited back to the ISO, as they were under a superseded version of the RMR contracts known as the "B" Contract.

RMR generators also can elect to operate under "Condition 2" of the RMR Agreement, which was designed for units that are not competitive in energy or ancillary services markets. Under this alternative, the ISO pays 100 percent of the unit's fixed costs (assuming target availability), and the owner is not allowed to use the unit's capacity in the competitive markets for the owner's benefit. However, when the ISO dispatches the unit for reliability purposes, the owner *must* bid all capacity above that dispatched by the ISO into subsequent energy and ancillary services markets, at prices determined by formulas in the contract, and resulting market revenues are credited to the ISO.

III. History of the RMR Agreements and Settlements Reached to Date

a. Original RMR Agreement Filings

As part of the process of restructuring the California electricity market, the ISO proposed in a March 31, 1997, filing to the Commission (as amended August 15, 1997) a *pro forma* Master Must-Run Agreement that included the major rate and contract terms for service. In an order issued October 30, 1997, the Commission accepted the *pro forma* Must-Run Agreement on a provisional basis, subject to modification and with changes required to be filed by October 31, 1998.[4]

This *pro forma* Agreement included three mutually exclusive sets of conditions, (Conditions of Must Run Agreement A, B, and C, or the "A" Contract, the "B" Contract, and the "C" Contract). Only one Condition would apply to a unit at a time. Under the "A" Contract, the unit could sell into forward markets or under bilateral contracts, and the owner retained all market revenues. When the ISO called a unit, the owner was paid variable costs for energy and a pro-rata share of the unit's annual fixed costs based on estimated annual megawatt-hours ("MWh") output.

The "B" Contract provided an availability payment intended to cover all annual fixed costs, both those associated with operations and with investment. It also provided a payment for variable running costs when the ISO called the unit. Units under the "B" Contract could participate in the market, but 90 percent of market revenues (net of variable operating costs) were credited back against the availability payment. Revenues from sales under bilateral contracts would also be credited back to the availability payment.

Unlike the other two forms of contract, under the "C" Contract an owner gave up all rights to sell into markets or under bilateral contracts, in exchange for the ISO's covering all costs of the unit. Under the "C" Contract, the owner was paid the unit's fixed costs (including annual recovery of the initial capital investment) as an availability payment, as well as its variable operating costs.

On October 31, 1997, in Docket No. ER98-495-000, PG&E filed several unexecuted, facility-specific Must-Run Agreements similar to the ISO's *pro forma* version, which established rates, terms and conditions for the provision of RMR services to the ISO, including the units now owned by the Southern Parties.[5] On December 17, 1997, the Commission accepted the proposed RMR Agreements for filing, suspended them for a nominal period and set them for hearing. In that Order, the Commission deemed the ISO's version of a *pro forma* Must-Run Agreement to have been superseded by the Must Run Agreements filed by PG&E, SDG&E, and SCE, finding that only those sellers' proposed Must-Run Agreements qualified as the filed rates for service to the ISO.[6]

On January 29, 1998, PG&E filed amendments to fourteen of its Must-Run agreements in Docket No. ER98-1614-000 to add Black Start service and to revise billing and payment terms, certain rates, and unit performance characteristics. PG&E filed errata on March 6, 1998, in Docket No. ER98-2145-000. On March 30, 1998, the Commission accepted, suspended, set for hearing and consolidated the filings with Docket No. ER98-495-000.[7]

On February 10, 1998, an order of the Chief Administrative Law Judge severed the rate issues from the non-rate terms and conditions in the three proceedings involving PG&E, SDG&E, and SCE, with rate issues to be decided in the individual utility dockets, and nonrate terms and conditions to be decided on a consolidated basis. *Southern California Edison Co.*, 82 FERC ¶ 63,011 (1998). Subsequent settlement negotiations, including those mediated by the Chief Judge, addressed rates and non-rate terms and conditions together.

b. The April 1999 Stipulation and Agreement

On April 2, 1999, after more than a year of intensive negotiation, the ISO, the RMR unit owners, the Responsible Utilities (who had by then divested much of their RMR generation), and other parties filed the April 2 Stipulation, a major, partial settlement of the issues set for hearing by the Commission in its earlier orders. The April 2 Stipulation resolved many of the contested issues concerning terms and conditions of the RMR Agreements, by establishing a new *pro forma* RMR Agreement. This new RMR Agreement replaced the original "A," "B," and "C" Contracts with the terms for Condition 1 and Condition 2 currently in force. It also set the "Annual Fixed Revenue Requirement" ("AFRR") for each generator's RMR units, the rate formulas and components of the variable cost payment, and the so called "prepaid startup" payments. Many of the rates and terms of the new *pro forma* RMR Agreement were designed to address major concerns about adverse market distortions resulting from the original agreements. These concerns had been raised by the Market Surveillance Committee advising the ISO, as well as by the ISO's Department of Market Analysis (then known as the Market Surveillance Unit).

A copy of the April 2 Stipulation was marked and received into evidence in this case as Exhibit JT-1. Facility-specific RMR Agreements following the new form of contract pertaining to the Southern units were also filed with the Commission on April 12, 1999, and were marked and received into evidence in this case as Exhibit JT-2. The Commission approved that uncontested partial settlement and the new RMR Agreements by order issued May 28, 1999.[8]

Although the transfer of the Contra Costa, Pittsburg, and Potrero power plants from PG&E to the Southern Parties did not occur until April 16, 1999, the Southern Parties had entered into a binding purchase commitment in November 1998. Accordingly, they participated and were represented by legal counsel in the negotiations leading to the April 2 Stipulation. The Southern Parties also were among the parties who signed the April 2 Stipulation. The parties also have agreed to a Second Stipulation and Agreement ("Second Stipulation"), which will settle, on a generic basis, a number of additional issues that were reserved in the April 2 Stipulation. The Second Stipulation is expected to be filed shortly.

c. Other RMR Settlements Reached to Date

In addition to the two foregoing generic settlements, there also have been numerous settlements involving individual RMR generators with respect to the three generator-specific issues enumerated below for decision in this case (Issues 1, 3 and 4, as specified in Article X, Part C of the April 2 Stipulation). On July 1, 1999, Geysers Power Company, LLC, PG&E, the ISO, and the EOB filed an Offer of Settlement as to specific issues related to RMR charges from generation units owned by Geysers Power. The Commission approved this settlement on January 31, 2000.[9] On August 31, 1999, Williams Energy Marketing and Trading Company ("Williams"), Edison, the ISO, and the EOB filed an Offer of Settlement as to specific issues relating to Williams' RMR Rate Schedules. On September 8, 1999, Reliant Energy Etiwanda, L.L.C. and Reliant Energy Mandalay, L.L.C. (collectively, "Reliant"), Edison, the ISO, and EOB filed an Offer of Settlement as to specific issues relating to Reliant's RMR Rate Schedules. The Commission approved the Reliant and Williams settlements on January 31, 2000.[10]

On November 3, 1999, PG&E, the ISO, and the EOB filed an Offer of Settlement as to specific issues related to RMR charges from units that continue to be owned and operated by PG&E (the Helms Pumped Storage, Humboldt Bay, Hunters Point, Kings River, and San Joaquin power plants). The Commission approved the PG&E Settlement on January 13, 2000.[11] On November 12, 1999, PG&E, the ISO, and EOB filed an Offer of Settlement as to specific issues relating to PG&E's RMR Rate Schedules for two RMR plants (the Moss Landing and Oakland Power Plants), for the period before PG&E sold the plants. The Commission approved the latter PG&E Settlement on January 14, 2000.[12] On November 16, 1999, Duke Energy Moss Landing LLC, Duke Energy Oakland LLC (collectively, "DEML/DEO"), PG&E, the ISO and EOB filed an Offer of Settlement as to specific issues relating to DEML/DEO's RMR Rate Schedules and other matters. The Commission approved this Settlement on January 28, 2000.[13] On March 3, 2000, in Docket No. ER99-3603-000, PG&E, the ISO and EOB filed an Offer of Settlement regarding a PG&E-operated RMR facility known as the FMC Turbine. That uncontested settlement was certified by the Presiding Judge [in the instant proceedings] and is pending before the Commission. Finally, on March 31, 2000, Duke Energy South Bay, LLC ("DESB"), the ISO, SDG&E, and the EOB filed in Docket Nos. ER98-496-000, *et al.*, an Offer of Settlement relating to DESB's RMR Rate Schedule. That offer is pending before the Presiding Judge.

d. Other Pertinent Orders

In addition to the various Commission orders discussed above, two additional orders pertain to this present proceeding and bear mention here. First, in an unpublished Letter Order dated March 31, 1999, in Docket Nos. ER98-1833-000 and ER98-1842-000, the Southern Parties received Commission authorization to engage in sales of energy, capacity and ancillary services at market-based rates. Second, in an order issued March 29, 1999, the Commission authorized the transfer of the jurisdictional facilities at the Contra Costa, Pittsburg, and Potrero power plants, and the applicable RMR contracts, from PG&E to the Southern Parties.[14]

IV. <u>The Issues Reserved for Resolution in this Case</u>

Certain issues were reserved in the Second Stipulation for resolution in subsequent hearings or settlements. Among these are the three issues set for hearing in the instant proceedings. As specified in the April 2 Stipulation, Article X., Part C., items 1, 3 and 4 (*see* Exh. JT-1 at 64), those three issues (Nos. 1, 3, and 4) are as follows:

1. What is the appropriate level of the Fixed Option Payment under each Revised RMR Rate Schedule?

3. 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?

4. 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?

B. SUPPLEMENTAL PROCEDURAL HISTORY

The November 16, 1999 Order of Chief Judge Designating Presiding Administrative Law Judge in these dockets made them subject to Track One (fast track) of the procedural time standards for hearing cases. Track One of the procedural time standards for hearing cases requires the hearing to commence no later than 19.5 weeks after the date the Chief Judge designates the Presiding Judge; it requires the Initial Decision to issue no later than 29.5 weeks after the date the Chief Judge designates the Presiding Judge. Accordingly, these proceedings were conducted on an expedited basis.

Company direct testimony and exhibits were filed on December 22, 1999. Staff/ CPUC/EOB/Intervenor direct and answering testimony and exhibits were filed on February 8, 2000. Rebuttal testimony and exhibits were filed on March 1, 2000. A joint stipulation of contested issues was filed on March 17, 2000. The evidentiary hearing was conducted from March 20, 2000 through March 24, 2000. Hearing transcript corrections were approved, and the record closed, on April 5, 2000. Initial Briefs ("IB") were filed on April 14, 2000; Reply Briefs ("RB") were filed on April 28, 2000.

C. ISSUE ANALYSES

I. What is the Appropriate Level of the Fixed Option Payment Under Each Revised RMR Rate Schedule?

To reiterate, RMR service rates are cost-based and consist of two (2) discrete components: a "variable cost" component and an "availability" component. The variable cost component is a "pass through" amount, representing the actual monthly costs incurred by the RMR unit owner to provide energy or ancillary services to the ISO pursuant to ISO dispatch orders. It provides neither fixed cost recovery nor profit to the RMR unit owner. The variable cost component of Southern Parties' RMR service to the ISO is not at issue in this proceeding. The availability component of RMR service is a fixed amount paid to the RMR unit owner on a monthly basis for maintaining the unit's availability to the ISO. In contrast to the variable cost component, the availability component is not based on any quantity of energy or ancillary services which the RMR unit provides to the ISO. The availability component payment (the "Fixed Option Payment" or "FOP")-- expressed as a percentage of an RMR unit's fixed costs-- is the mechanism which allows the RMR unit owner to recover the fixed costs of satisfying RMR obligations to the ISO. The appropriate FOP for Southern Parties' RMR units is the principal issue in these proceedings.

a. *Party Positions*

1. <u>Southern Parties</u>

Southern Parties essentially maintain that the FOP should be calculated in accordance with traditional cost-based rate principles. They analogize RMR service to a traditional "capacity" product, contending that the resemblance supports establishing each RMR unit's FOP by allocating the unit's settled revenue requirement (AFRR) to RMR service in direct proportion to the percentage of time the ISO relies on the unit to provide RMR service. Proceeding from this premise, Southern Parties calculate the FOP for each RMR unit pursuant to a three (3) step methodology which focuses on RMR unit availability, energy/ancillary services and uncompensated costs. The methodology first determines the number of hours per year that the ISO reserves each RMR unit for reliability purposes ("Reserved Hours"),[1] and aggregates Reserved Hours for all units. The methodology next determines the number of hours per year that each RMR unit actually provides energy or ancillary services to the ISO ("Service Hours"),[2] and aggregates Service Hours for all units. The aggregate Reserved Hours figure establishes an upper limit to a range of potential FOPs; the aggregate Service Hours figure establishes the lower limit to the range. The final step in Southern Parties' FOP calculation methodology is to establish an appropriate FOP within the range based on whether the RMR Agreements impose additional uncompensated costs. Southern Parties contend that the RMR Agreements impose uncompensated opportunity costs, and therefore conclude that the appropriate FOP lies at the high extreme of the range.

Southern Parties criticize the other parties' net incremental cost methodologies for calculating RMR unit FOP on numerous grounds. Southern Parties emphasize first that any FOP established in this proceeding must be consistent with the April 2 Stipulation. They contend that an FOP based on the net incremental cost of providing RMR service cannot recover the $158.8 million AFRR reflected in the April 2 Stipulation, let alone the $463 million premium Southern Parties paid to acquire the RMR units. Southern Parties assert that compensating RMR service at net incremental cost is inconsistent with their reasonable expectations for the bargain they made when they purchased the RMR units from PG&E, and that this assertion is supported by the fact that PG&E did not provide service from the units at net incremental cost. Southern Parties also maintain that compensating RMR service at net incremental cost is confiscatory, inconsistent with RMR compensation currently paid to other generators, artificially suppresses RMR service rates below the level required to mitigate local market power, and inadequate to prevent RMR generator migration from Condition 1 status to Condition 2-- to the detriment of competitive markets as well as California consumers.

2. Joint Parties

Joint Parties[3] frame the issue as one of first impression, arguing that compensating Southern Parties' RMR obligations through cost-based rates designed to recover sunk costs is inconsistent with the market rate/ISO paradigm which California has implemented. Joint Parties contend that the procedural history of California's energy industry restructuring establishes that: (1) RMR obligations were a necessary condition of market-based rate authority for generating units which otherwise could exercise local market power due to location and other historical factors; and (2) all generators must seek return of and on investment from the competitive markets which restructuring created. According to Joint Parties, it is inaccurate to characterize RMR obligations as a discrete service or "capacity" product. They maintain instead that RMR obligations merely are a contractual mechanism to prevent generators enjoying unique– and therefore essential– locations in the interconnected grid from exploiting local market power in limited circumstances. Joint Parties emphasize that providing RMR support to the ISO is incidental to these units' dominant function as merchants in the competitive energy and ancillary services markets. Further, they underscore the fact that Southern Parties' RMR units differ from generating facilities that traditionally have recovered sunk costs through cost-based rates in that Southern Parties have been granted authority to charge market-based rates for the energy/ancillary services the units provide, and to retain all revenues which those rates generate. Joint Parties also stress that Southern Parties' RMR obligations differ from capacity sales in that Southern Parties always retain the full economic value associated with RMR unit availability to the ISO.

Based on the preceding points, Joint Parties argue that a net incremental cost methodology should be used to establish appropriate FOPs for Southern Parties' RMR units. They maintain that Southern Parties' RMR obligations are the local market power mitigation *quid pro quo* for Commission authority to charge market-based rates for RMR unit energy/ancillary services and, as a consequence, RMR unit FOP merely should reimburse Southern Parties for costs incurred in response to ISO calls in the limited circumstances when an RMR unit is not making market sales.[4] Joint Parties assert that local market power mitigating RMR obligations should make Southern Parties neither worse off nor better off than any other merchant plant operator, emphasizing that compensating Southern Parties' RMR obligations through rates designed to recover a predominant percentage of sunk costs significantly would advantage Southern Parties *vis-a-vis* the vast majority of merchant generators who lack the local market power that RMR obligations are intended to mitigate.

3. Staff

Staff also frames the issue as one of first impression. According to Staff, RMR service is unlike any previously regulated capacity service. Staff therefore maintains it is inappropriate for Southern Parties to characterize RMR obligations as vestiges of the regulated utility structure which California recently superceded with a market rate/ISO model. Staff contrasts the cost-based rates appropriate to a regulated climate with Southern Parties' ability to charge market-based rates in the new competitive environment. Staff points out that the sole purpose of RMR obligations is to mitigate the local market power that a competitive environment would permit RMR unit owners like Southern Parties to exploit in the absence of such obligations. Moreover, Staff emphasizes that while market-based rates enable Southern Parties to maximize and retain RMR unit revenues, Southern Parties propose to minimize the corollary market risk by transferring most of that risk to the ISO through the FOP. Staff argues that since market revenues are not credited to the ISO under Condition 1 of the RMR Agreements, the ISO should not bear Condition 1 unit fixed costs unless the unit actually is called to provide service. Accordingly, Staff endorses a modified net incremental cost approach under which appropriate FOPs would be established by netting each RMR unit's incremental costs/benefits, then adding an "incentive payment" equal to ten percent (10%) of the unit's AFRR.[5] Staff maintains that this approach is entirely consistent with the April 2 Stipulation, noting that the stipulation neither specifies an FOP calculation methodology nor establishes a set level of cost recovery. Staff also maintains that its proposed incentive payment undermines Southern Parties' criticisms that a net incremental cost approach is confiscatory, artificially suppresses RMR service rates below the level required to mitigate local market power, difficult to quantify, and inadequate to prevent RMR generator migration from Condition 1 status to Condition 2.

4. CPUC

CPUC takes the position that RMR obligations do not constitute a discrete service. CPUC maintains instead that the RMR Agreement proviso for cost-based rates is simply a local market power mitigation tool, and is applicable only under limited circumstances. CPUC emphasizes that Southern Parties will receive market rates under most circumstances, and that cost-based reimbursement for RMR obligations ensures that Southern Parties are made whole in the limited remainder of circumstances where they cannot charge market rates due to the potential to exercise local market power. As a consequence, CPUC argues that compensating Southern Parties' RMR obligations at anything above net incremental cost would contravene the very purpose of the RMR Agreements because any such compensation necessarily would reward the local market power the contracts were intended to mitigate. CPUC opposes any RMR incentive payment or "adder" for the same reason. CPUC maintains that its pure net incremental cost approach is entirely consistent with the April 2 Stipulation, and dismisses Southern Parties' concern that the approach will encourage RMR generator migration from Condition 1 status to Condition 2.

5. EOB

EOB argues that RMR obligations are a local market power mitigation measure, and therefore comprise neither a capacity product nor a discrete reliability service which might imply sunk cost recovery. EOB essentially characterizes the obligations as a condition precedent to Commission authority for RMR unit owners to charge market-based rates for energy and ancillary services. EOB maintains that since Southern Parties have been authorized to charge market-based rates, they must seek sunk cost recovery from the same sources as non-RMR unit owners authorized to charge market-based rates: the competitive energy and ancillary services markets. EOB submits that RMR unit sunk cost recovery through the FOP inappropriately would subsidize Southern Parties' profit-seeking activities, and therefore endorses net incremental cost reimbursement for their RMR obligations. Although EOB does not oppose a ten percent (10%) supplement to the net incremental cost of Southern Parties' RMR obligations, it maintains that any such supplement should not be based on AFRR because AFRR bears no relation to either the cost of satisfying RMR Agreement obligations or to the amount of energy provided to satisfy reliability requirements.

b. *Discussion*

I find this to be an issue of first impression. Although a few cases cited by the parties have addressed RMR or analogous obligations in other contexts, this case presents the specific issue of appropriate RMR compensation in a market-based rate scenario without revenue credits.

1. Introduction

The issue is problematic for a number of reasons. Primary among these is the historical fact that Southern Parties' RMR units originally were constructed in a regulated environment where *total* cost of service was the paramount consideration. Exh. PGE-3, at p. 10; Exh. SOU-19, at pp. 4-5. In that monopoly/bundled service environment, load pocket generating facilities and transmission facilities were sometimes fungible-- the choice between them being made according to their relative costs to the bundled service provider and, ultimately, to consumers. *Id.*; Tr. 498-99, 584-85. Southern Parties' RMR units also were constructed in a regulated environment *guaranteeing* the bundled service provider the opportunity to earn a return of and on investment through cost-based rates. Exh. PGE-3, at p. 10. Coupled with a monopoly service territory based on total cost of service, those rates provided neither incentive nor opportunity for the service provider to exercise local market power. Exh. PGE-3, at p. 10; Exh. SOU-19, at p. 5.

Superimpose deregulation, functional unbundling, competition and market-based rates. Compound the scenario with the implementation of open transmission access, generating asset divestiture by transmission owners and an independent statewide transmission system operator tasked with ensuring transmission grid reliability. Adapting the historical (regulated) framework to this new competitive paradigm produced anomalies. One of these anomalies was that various generating units originally constructed in lieu of transmission facilities became absolutely essential to transmission grid reliability at certain times. Exh. PGE-3, at p. 13; Exh. SD-1, at pp. 3-4. This situation, coupled with the introduction of market-based rates, created a potential for some generators to charge exorbitant rates through the exercise of occasional local market power resulting from their units' indispensability to the transmission grid. Exh. PGE-3, at pp. 13-14; Exh. SOU-19, at p. 5. The RMR Agreements at issue were intended to eliminate the financial incentive for RMR unit owners to exercise such market power by establishing cost-based rates for essential transmission grid support.

The preceding summary illustrates that this issue arises out of various interrelated incongruities between a historical (regulated) monopoly/bundled service environment guaranteeing service providers the opportunity to earn a return of and on investment through cost-based rates and a new (competitive) functionally unbundled environment offering service providers the opportunity to earn a return of and on investment through market-based rates. RMR units are a hybrid– a bridge between the two environments, exhibiting characteristics of each. The issue, then, comes down to which paradigm forms the appropriate basis on which to establish RMR rates in general and, more specifically, the appropriate basis on which to calculate Southern Parties' RMR unit availability charges.

Joint Parties, Staff, CPUC and EOB all highlight the fact that Southern Parties may now charge market-based rates for energy and ancillary services, arguing as a consequence that Southern Parties must pursue any opportunity to earn return of/on their investment through these market-based rates. They contend that RMR obligations are merely local market power mitigation mechanisms and, as such, properly should be compensated at net incremental cost. They maintain that compensating Southern Parties' RMR obligations under traditional cost-based rates would place Southern Parties at a significant competitive advantage over energy/ancillary service providers that do not own RMR units.

Southern Parties counter that RMR Agreements establish a novel and discrete service– a vestige of the regulated environment incorporating an availability component which is analogous to a traditional capacity reservation-- and that the rates for such service appropriately subsume a sunk cost component. Moreover, they maintain that net incremental cost reimbursement under Southern Parties' RMR Agreements would be inconsistent with RMR compensation currently paid to other generators, also pointing out that PG&E was not compensated on a net incremental cost basis when it owned the units. Southern Parties submit that these facts, coupled with PG&E representations concerning RMR unit revenues and the express terms of the April 2 Stipulation, establish that Southern Parties purchased the RMR units based on a reasonable expectation that they would have the opportunity to recover sunk costs through traditional cost-based rates.

2. RMR Availability Obligations: A Discrete Capacity Service?

The Commission clearly recognizes a distinction between the RMR contract obligation to deliver energy/ancillary services in response to ISO dispatch notices and the RMR contract obligation to maintain RMR unit availability to ensure transmission system reliability:

> RMR units are generating units in California that must be scheduled and dispatched during certain hours, regardless of the unit's supply bid, because of physical limitations on the transmission grid. Their purpose is mainly to ensure local reliability. RMR units enter into contracts with the ISO that allow the ISO to require that the unit be available to the market during certain hours. Under the RMR contracts, the ISO pays the RMR unit a portion of its fixed costs to stand ready to deliver an hourly minimum

> energy requirement set by the ISO (annual availability payment). When generating to ensure reliability, the contracts also allow the RMR unit to receive for the energy it produces either the variable cost payment included in the contract or market prices.

California Independent System Operator Corp., 90 FERC ¶ 61,345, at mimeo p. 1 (2000). It therefore is indisputable that the availability payment component of RMR rates is intended to compensate the RMR unit owner for standing ready to provide energy/ancillary services if required by the ISO. This characteristic tends to support record testimony that RMR obligations constitute a discrete capacity product or service. Exh. SOU-1, at pp. 5, 10-11; Tr. 488, 932, 935.

A persuasive demonstration that RMR availability obligations are analogous to traditional capacity reservations would provide additional support for a conclusion that RMR obligations constitute a discrete capacity product or service. Southern Parties submit that the RMR Agreements themselves substantiate a capacity reservation analogy on numerous grounds. According to Southern Parties, the RMR Agreements establish that RMR availability obligations are analogous to traditional capacity reservations because: (1) the monthly availability payments are based on target available hours instead of MWhs (Exh. JT-2, Schedules B); (2) the RMR availability obligations are unit specific and physically firm (Exh. JT-2, §§ 4.1); and (3) the non-performance penalties are calculated by reference to capacity factors instead of energy costs (Exh. JT-2, §§ 8.5).

The record demonstrates that the similarities Southern Parties cite to support the capacity reservation analogy are superficial. First, Southern Parties' attempt to analogize RMR availability obligations to traditional capacity reservations ignores a fundamental difference between the two: whereas a traditional firm capacity service provider is restricted from selling output (e.g., energy/ancillary services) to third parties in the event the capacity purchaser calls on the output, Southern Parties' RMR availability obligations impose no such restriction. Exh. PGE-17, at pp. 5-6; Exh. PGE-18, at pp. 4-6; Exh. ISO-5, at pp. 5-8; Tr. 933-35. Moreover, in contrast to traditional (cost-based rate) firm capacity service providers, Southern Parties may sell their RMR unit outputs at market prices. Exh. PGE-17, at pp. 5-6; Exh. PGE-18, at pp. 5-6; Exh. ISO-5, at p. 7; Exh. S-12, at p. 11. Southern Parties therefore retain virtually all economic benefits of their RMR unit generating capability whenever market prices exceed variable operating costs. Exh. ISO-5, at p. 7. This characteristic further distinguishes Southern Parties' RMR unit availability obligations from traditional firm capacity reservations. Generating unit owners normally may resell unscheduled energy under traditional firm capacity contracts, but they are required to credit proportionate revenues against any fixed costs allocated to the capacity contract holder(s). Exh. S-12, at pp. 18-19. *Accord TECO Power Services Corp.*, 53 FERC ¶ 61,202, at p. 61,813 (1990). The RMR Agreements at issue do not require Southern Parties to credit any market revenues back to the ISO. It follows that

Southern Parties' attempt to analogize RMR unit availability obligations to traditional firm capacity reservations does not support a conclusion that RMR obligations constitute a discrete capacity product or service.[6]

The same holds true for an analysis of RMR obligations' fundamental purpose. That purpose indisputably is to mitigate the potential for RMR unit owners to exercise local market power at times when the units are essential to transmission grid reliability. Exh. SOU-1, at pp. 13-14; Exh. PGE-17, at pp. 4-5; Exh. SCE-2, at pp. 21-22; Exh. ISO-1, at p. 7; Exh. S-1, at pp. 9-10; Exh. PUC-1, at pp. 4-5; Exh. EOB-1, at p. 8. *Accord California Independent System Operator Corp.*, 90 FERC ¶ 61,345, at mimeo p. 9 (2000). *See also Pacific Gas and Electric Company*, 81 FERC ¶ 61,122, at p. 61,557 (1997); *Pacific Gas and Electric Company*, 77 FERC ¶ 61,204, at pp. 61,833-34 (1996). As previously observed, that potential would not exist had the RMR unit owners not sought and been granted authority to charge market-based rates for the energy/ancillary services provided by the units. Southern Parties expressly acknowledged this fact in their applications for authority to charge market-based rates for the RMR units at issue in this proceeding (Exh. SOU-13, at p. 1; Exh. SOU-14, at p. 2), which were approved by letter order issued March 31, 1999 in Docket Nos. ER99-1833-000, ER99-1841-000 and ER99-1842-000. Exh. SOU-15. It follows that while RMR obligations may not rise to the level of *quid pro quo* for RMR unit authority to charge market-based rates for energy/ancillary services, the obligations clearly constitute necessary conditions precedent for such authority. *See Duke Energy Moss Landing, LLC, et al.,* 83 FERC ¶ 61,317, at pp. 62,292-93 and n.1 (1998); *Pacific Gas and Electric Company*, 81 FERC ¶ 61,122, at p. 61,557 (1997); *Pacific Gas and Electric Company*, 77 FERC ¶ 61,204, at pp. 61,833-34 (1996). *See also Consumers Energy Co.*, 85 FERC ¶ 61,121, at p. 61,447 (1998); *Commonwealth Edison Co.*, 82 FERC ¶ 61,317, at p. 62,249 and n.4 (1998); *Delmarva Power & Light Co.*, 76 FERC ¶ 61,331, at p. 62,582 (1996), *reh'g dismissed*, 80 FERC ¶ 61,330 (1997). In the absence of these conditions, RMR unit owners' market-based rate authority would permit them to withhold– or threaten to withhold– essential transmission grid support, thereby artificially inflating the price of that support.[7] Exh. SD-2, at pp. 12-14; Exh. ISO-5, at pp. 3-4; Exh. PGE-18, at p. 4; Exh. SOU-1, at p. 13. RMR obligations, then, are not properly characterized as a discrete product or service. Instead, they are simply contractual mechanisms enabling generators enjoying unique– and therefore essential– locations in the interconnected transmission grid to participate in competitive markets for energy and ancillary services by mitigating the generators' ability to exploit local market power in limited circumstances. Viewed in this light, RMR obligations actually *create* potential value for RMR unit owners by providing a mechanism to mitigate local market power which otherwise might compel them to charge cost-based rates (or some functional equivalent achieved through revenue credits, etc.) for the energy/ancillary services the units produce.

3. <u>Appropriate RMR Availability Component Compensation</u>

It is axiomatic under traditional cost-of-service ratemaking principles that rates must provide an opportunity for service providers to recover their cost of service, which subsumes both a return of and on investment. *See, e.g., FPC v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944) ("*Hope*"); *Carolina Power & Light Co. v. FERC,* 860 F. 2d 1097, 1098 (D.C. Cir. 1988) ("*Carolina Power*"). Southern Parties focus on this requirement to support their contention that each RMR unit's FOP should be calculated by allocating the unit's settled AFRR in direct proportion to the number of hours per year that the ISO reserves it for reliability purposes. They maintain that such allocation is warranted because, consistent with *Hope* and *Carolina Power*, it would recover the appropriate proportion of the $158.8 million composite AFRR reflected in the April 2 Stipulation through the FOP.[8] Joint Parties, Staff, CPUC and EOB emphasize that Southern Parties have been authorized to charge market-based rates for energy and ancillary services, arguing as a consequence that Southern Parties' RMR obligations should be compensated at net incremental cost because they have an otherwise unfettered opportunity to seek return of/on their RMR unit investment from the competitive energy and ancillary services markets.

Southern Parties' position is based on the implied premise that RMR availability obligations are analogous to traditional capacity reservations, and therefore constitute a discrete product or service. As such, the traditional cost-of-service ratemaking principles articulated in *Hope* and *Carolina Power* conceivably might support an opportunity for Southern Parties to recover a proportionate amount of the sunk costs associated with their RMR availability obligations through dedicated, cost-based, rates-- in this case, the FOP. The premise that RMR availability obligations constitute a discrete product or service, however, has been discredited. See Subsection C (I) (b) (2), *supra*. Since *Hope* and *Carolina Power* address costs of *service*, those cases logically should be inapplicable to RMR obligations, which are local market power mitigation measures that otherwise do not impact the actual *services* (energy/ancillary services) which Southern Parties' RMR units provide. Exh. ISO-6, at pp. 12-13; Exh. PGE-18, at pp. 4-6. More important, Southern Parties ignore the fact that *Hope* and *Carolina Power* reflect a superceded cost-of-service paradigm. That framework envisioned neither competition among service providers nor any opportunity for them to earn market-based rates. In contrast to the regulated environment in which *Hope* and *Carolina Power* were decided, California's electric industry has been restructured to rely on competitive markets to establish appropriate rates for services. Exh. PGE-17, at p. 4; Exh. PUC-1, at pp. 10-12. *Also see generally* Cal. Pub. Util. Code § 330, *et seq.* (Deering 2000). And unlike the regulated markets addressed in *Hope* and *Carolina Power*, competitive markets do not guarantee the opportunity for return of/on investment through cost-based rates. That opportunity is provided through authority to charge market-based rates for services. Exh. PGE-17, at p. 4; Exh. SD-2, at p. 17.

Southern Parties essentially argue for the best of both ratemaking worlds: cost-based (regulated) security coupled with market rate (competitive) opportunity. On one hand, Southern parties propose to guarantee themselves more than 75 percent of the RMR units' composite AFRR by allocating it to ISO availability via the FOP. Exh. SOU-6. On the other hand, they propose to keep all revenues earned from market-based rate sales of energy/ancillary services. Exh. SOU-1, at pp. 14-16; Exh. S-12, at pp. 11-12. The result would be a 75 percent transfer of the risk associated with Southern Parties' RMR unit acquisitions to the ISO (ultimately, to California consumers) coupled with Southern Parties' retention of all benefits associated with the acquisitions. This scenario is inappropriate for numerous reasons.

First, even in a pure cost-of-service environment, *Hope* and *Carolina Power* do not unconditionally guarantee return of/on investment. Those cases stand for the more limited ratemaking principle that rates must provide an *opportunity* for return of/on investment. *Hope*, 320 U.S. at 603; *Carolina Power*, 860 F. 2d at 1098. Southern Parties have been provided that opportunity through the authority to charge market-based rates for energy/ancillary services.[9] The return requirements articulated in *Hope* and *Carolina Power* therefore have been satisfied. There is no legitimate basis for providing a supplemental opportunity for return of/on investment, let alone the supplemental *guarantee* Southern Parties propose. Any such supplement would constitute an inappropriate subsidy to Southern Parties' participation in the competitive markets for energy/ancillary services. Second, Southern Parties' proposal is inequitable. It exhibits utter lack of proportionality between potential reward-- in the form of opportunities to earn market-based revenues from sales of energy/ancillary services-- and risk– in the form of sunk cost responsibility. Southern Parties exacerbate this lack of proportionality by obscuring their RMR units' dominant function as competitive energy/ancillary service providers. RMR availability obligations are merely the incidental local market power mitigation mechanisms which enable RMR units to reap the potential benefits of their dominant function. Third, Southern Parties' proposal blurs the fundamental distinction between RMR unit operation under Conditions 1 and 2 of the RMR Agreements. Only RMR Agreement Condition 2 operations legitimately fall within the purview of *Hope* and *Carolina Power*. But while RMR unit operation under Condition 2 guarantees AFRR recovery, it also requires all market revenues derived from energy/ancillary service sales to be credited to the ISO.[10]

RMR obligations are simply contractual mechanisms enabling generators enjoying unique– and therefore essential– locations in the interconnected transmission grid to participate in competitive markets for energy and ancillary services by mitigating those generators' ability to exploit local market power in limited circumstances. It follows that RMR unit availability should be compensated in an economically "transparent" manner: appropriate compensation should mitigate local market power, but neither unnecessarily advantage nor unnecessarily disadvantage RMR unit participation in competitive markets for energy and ancillary services. Net incremental cost[11] compensation achieves these objectives.

The record establishes that each of the Joint Parties, Staff, CPUC and EOB net incremental cost compensation proposals would reimburse Southern Parties for all costs– including fixed costs, variable costs and reasonably identifiable opportunity costs-- 8associated with their RMR unit availability obligations.[12] Exh. PGE-1, at pp. 5-9; Exh. PGE-21 (revised); Exh. SD-1, at pp. 6-7; Exh. SCE-2, at pp. 9-11; Exh. ISO-1, at pp. 23-25, 27; Exh. PUC-1, at pp. 12-13; Exh. EOB-1, at pp. 3-4; Staff IB, at pp. 13-15 (endorsing Exhs. PGE-1, SD-1, ISO-1, PUC-1). The record also establishes that each proposal ensures that any RMR unit rendered uneconomic by net incremental cost compensation remains viable through "going forward" cost reimbursement.[13] Exh. PGE-1, at p. 7; Exh. SD-1, at p. 7; Exh. SCE-2, at pp. 9-10; Exh. ISO-1, at pp. 24-25; Exh. PUC-1, at p. 16; Exh. EOB-1, at pp. 3-4. Most important, the record establishes that compensating Southern Parties' RMR availability obligations at net incremental cost does not deprive them of any significant opportunity to participate in the competitive markets for energy/ancillary services or to maximize the financial rewards associated with that participation. Exh. PGE-17, at pp. 4-6; Exh. PGE-18, at pp. 4-6; Exh. ISO-5, at pp. 5, 7-8; Exh. S-12, at p. 11. The record therefore is conclusive that compensating Southern Parties' RMR availability obligations at net incremental cost would not unnecessarily disadvantage their participation in the competitive markets for energy and ancillary services.

The record is equally conclusive that compensating Southern Parties' RMR availability obligations at net incremental cost would be far more consistent with the competitive paradigm adopted in California than the scheme Southern Parties propose. The California electric industry was restructured for the specific purpose of establishing appropriate rates through competitive markets. Exh. PGE-17, at p. 4; Exh. PUC-1, at pp. 10-12. *Also see generally* Cal. Pub. Util. Code § 330, *et seq.* (Deering 2000). Such markets do not provide the opportunity for return of/on investment through cost-based rates. Instead, that opportunity is provided through authority to charge market-based rates. Exh. PGE-17, at p. 4; Exh. SD-2, at p. 17. Since Southern Parties sought and were granted authority to charge market-based rates for their RMR unit energy and ancillary services (Exh. SOU-13, at p. 1; Exh. SOU-14, at p. 2), it would be antithetic to California's competitive paradigm to permit them to guarantee significant return of/on RMR unit investment through the FOP. It also would be antithetic artificially to suppress Southern Parties' RMR unit acquisition risk by transferring over 75% of that risk to the ISO/California consumers through the FOP. Any such transfer, moreover, not only would be inequitable to California consumers, but also would grant Southern Parties a considerable competitive advantage over other California energy/ancillary service providers by subsidizing Southern Parties' energy/ancillary service merchant operations.

Exh. PUC-1, at pp. 17, 26-28; Tr. 701-04. Finally, it would be disingenuous to reward (indirectly through the FOP) the local market power that imposing RMR obligations on Southern Parties was intended to mitigate in the first place. It follows that compensating Southern Parties' RMR availability obligations at net incremental cost would mitigate their potential to exercise local market power without conferring unnecessary advantages on their RMR unit participation in the competitive markets for energy/ancillary services.

Compensating Southern Parties' RMR availability obligations at net incremental cost has corollary advantages as well. Consistent with a competitive/economically efficient paradigm, compensating Southern Parties' RMR availability obligations at net incremental cost should encourage: (1) market-driven RMR unit allocation between RMR Agreement Conditions 1 and 2; and (2) appropriate price signals for potential replacement resources. Although the record indicates that it is conceptually desirable for RMR units to operate under RMR Agreement Condition 1, thereby contributing to more robust competitive energy/ancillary services markets (Exh. S-12, at p. 29; Exh. SCE-2, at p. 18; Tr. 553-54), Condition 1 operation is not necessarily the economically efficient alternative. Both the State of California and the Commission have expressed unequivocal commitments to rely on market forces to shape the new electric industry. It would be inconsistent with these commitments artificially to suppress market forces in the Condition 1/Condition 2 selection process through excessive RMR availability payments. This fact notwithstanding, the record suggests that such payments are unnecessary in any event because the potential for RMR unit migration from Condition 1 to Condition 2 is slight.[14] Exh. PGE-3, at pp. 32-38; Exh. PGE-1, at pp. 12-13. The record also establishes that numerous remedial options are available if Condition 1 to Condition 2 migration has any serious adverse market implications. Exh. PGE-1, at pp. 11-12; Exh. SCE-2, at pp. 61-62; Exh. JT-1, at p. 19. In addition, compensating Southern Parties' RMR availability obligations at net incremental cost would provide appropriate price signals for potential replacement resources. The record indicates that allocating sunk costs to RMR availability payments would create perverse incentives to invest in duplicative or uneconomic generation, transmission and demand-side management. Exh. S-12, at pp. 20-22; Exh. ISO-5, at pp. 10-11. In addition, allocating sunk costs to RMR availability payments also would undermine the ISO's ability meaningfully to determine and evaluate economically efficient alternatives to RMR generation under its Local Area Reliability System process. Exh. ISO-1, pp. 22-23.

The record establishes that with the exception of certain "incentive payments" addressed in Section C (I) (b) (4), *infra*, Joint Parties, Staff, CPUC and EOB all endorse basically the same net incremental cost compensation methodology for Southern Parties' RMR obligations. Exh. PGE-1, at pp. 5-10; Exh. SD-1, at pp. 6-7; Exh. SCE-2, at pp. 5-10; Exh. ISO-1, at pp. 23-25, 27; Exh. PUC-1, at pp. 12-19; Exh. EOB-1, at pp. 3-4; Exh. S-1, at pp. 26, 29; Staff IB, at pp. 13-15 (endorsing Exhs. PGE-1, SD-1, ISO-1, PUC-1). That methodology is based on the calculations of PG&E witness Weingart, as supplemented by the calculations/modeling assumptions of PG&E witness Livingston and ISO witness Theaker. Exh. PGE-3 through Exh.PGE-12; Exh. PGE-13 through Exh.PGE-16; Exh. ISO-2 through Exh. ISO-4. It reasonably accounts for, and fully compensates, all costs related to Southern Parties' RMR obligations. The record confirms that PGE witness Weingart computed RMR Agreement Condition 1 net incremental costs for each RMR unit by first summing RMR operations-related incremental costs and reasonably identifiable opportunity costs.[15] Exh. PGE-3, at p. 19; Exh. PGE-4 through Exh.PGE-12; Exh. PGE-13 through Exh.PGE-16; Exh. PGE-21 (revised). Net incremental costs were then derived by subtracting reasonably identifiable opportunity benefits (Exh. PGE-3, at pp. 24-27), and never were set lower than incremental administrative costs. Exh. PGE-3, at p. 27; Exh. PGE-9. In addition, the record confirms that going forward costs were calculated based on conservative estimates of anticipated market revenues. Exh. PGE-3, at p. 28; Exh. ISO-2 through Exh. ISO-4; Exh. S-1, at p. 34. Each RMR unit then was assigned the greater of net incremental cost or net going forward cost to establish the appropriate composite FOP. Exh. PGE-3, at p. 28; Exh. PGE-5. I find that this methodology compensates Southern Parties for all costs– including fixed costs, variable costs and reasonably identifiable opportunity costs– associated with their RMR obligations, and therefore adopt it for purposes of this proceeding.

4. The Proposed Incentive Payments

Although Joint Parties initially argued in favor of pure net incremental cost compensation through the FOP, they now endorse the additional incentive payment recommended by SCE Witness Joskow. Joint Parties IB, at p. 47 (referencing Exh. SCE-2, at pp. 10–11). Dr. Joskow recommended a supplemental FOP payment totaling ten percent (10%) of net incremental RMR-related costs (including fixed costs and projected variable costs) to make RMR obligations in themselves at least modestly rewarding to RMR unit owners. Exh. SCE-2, at pp. 10–11, 59; Tr. 974-75. Staff proposes a modified net incremental cost approach which incorporates an incentive payment totaling ten percent (10%) of the unit's AFRR in order to: (1) make RMR obligations modestly rewarding to RMR unit owners; and (2) reduce the risk of error associated with estimating net incremental costs. Exh. S-1, at pp. 29-30. CPUC supports pure net incremental cost compensation, opposing any RMR incentive payment whatsoever on the grounds that it is arbitrary and inappropriately would reward local market power that RMR obligations are intended to mitigate. CPUC IB, at pp. 9-10. Although EOB does not oppose adding a ten percent (10%) incentive payment to the net incremental cost of Southern Parties' RMR obligations, it opposes basing the incentive payment on AFRR because AFRR bears no relation to either the cost of satisfying RMR Agreement obligations or to the amount of energy provided to satisfy reliability requirements. EOB IB, at p. 21. Southern Parties roundly criticize the various proposed incentive payments as "fudge factors" intended to redeem the inadequacies of compensating Southern Parties' RMR obligations at net incremental cost. Southern Parties RB, at pp. 22-25.

None of the proposed incentive payments is appropriate. Joint Parties, Staff and EOB all have argued that Southern Parties' RMR obligations do not comprise a discrete product or service. Each has taken the position that those obligations merely constitute a local market power mitigation device-- a necessary condition for authority to charge market-based rates for Southern Parties' RMR unit energy/ancillary services. Moreover, each has taken the position that Southern Parties' market-based rate authority provides virtually unlimited opportunities for return of/on RMR unit investment and, as a consequence, that Southern Parties must seek such returns exclusively from competitive energy and ancillary services markets in the same manner as non-RMR unit generators. Having taken these positions, it is disingenuous for Joint Parties, Staff and EOB to hedge them by adding a gratuitous incentive payment.[16] At best, this amounts to a "fudge factor"; at worst, it constitutes a purposeful attempt to obscure the stark economic implications of compensating RMR obligations at net incremental cost.

The proposed incentive payments suffer substantive deficiencies as well. First, they are completely arbitrary. The preceding discussion demonstrates that the net incremental cost theory of RMR compensation provides no logical basis for a supplemental incentive payment. Under that theory, market-based rate authority provided the incentive for Southern Parties to assume RMR obligations. Exh. PGE-18, at p. 30. In addition, irrespective of benchmark, neither the Joskow nor Staff ten percent (10%) quantifier has any discernable objective basis. The record confirms instead that each quantifier is an unsupported value judgment bearing no relation to the record in this proceeding.[17] Tr. 983-85; Exh. S-1, at pp. 30-32. Each quantifier therefore is arbitrary and unreasonable. *See, e.g., United Distribution Companies v. FERC*, 88 F.3d 1105, 1187 (D.C. Cir. 1999). It follows that adopting a ten percent (10%) incentive payment would violate Section 313 of the Federal Power Act, as well as Section 706 of the Federal Administrative Procedure Act. 16 U.S.C. § 825l (1994); 5 U.S.C. § 706 (2) (A), (E) (1994). Staff's incentive payment proposal exhibits the additional deficiency of being benchmarked to AFRR. By definition, AFRR subsumes sunk costs. AFRR also is unrelated to actual ISO demands on the RMR units. Exh. PGE-18, at pp. 29-31.

5. The April 2 Stipulation and Related Southern Parties Criticisms

Irrespective of the preceding determinations, Southern Parties argue that compensating their RMR obligations at net incremental cost is inconsistent with their reasonable expectations when they purchased the RMR units from PG&E, and therefore denies them the benefit of their bargain. Southern Parties argue that compensating their RMR obligations at net incremental cost: (1) ignores PG&E and contractual assurances concerning RMR unit revenues which were substantial factors in Southern Parties' decision to purchase the units; (2) is inconsistent with RMR compensation currently paid to other generators; and (3) violates the express terms of the April 2 Stipulation. Southern Parties maintain that these circumstances establish that they purchased the RMR units based on a reasonable expectation that they would recover sunk costs through traditional cost-based rates for RMR availability.

The exclusive record support for Southern Parties' claim that the decision to purchase PG&E's RMR units was based on PG&E assurances of sunk cost recovery via dedicated RMR compensation (Exh. SOU-10, at pp. 10-11; Exh. SOU-13, at pp. 16-17) is reflected in a PG&E "POWER PLANT SALE Confidential Information Memorandum." Exh. PGE-29. At page 21, the memorandum addresses "MULTIPLE REVENUE STREAMS" and states that "the Plants can generate revenues by using various sales methods." Exh. SOU-18, at p. 2. Listed among seven (7) illustrative bullet point sales methods is a reference to "revenues from the Master Must Run Agreement with the ISO." *Id.* This reference provides absolutely no support for Southern Parties' claim that their decision to purchase PG&E's RMR units was based on any seller assurance of sunk cost recovery through RMR compensation.

The same holds true for Southern Parties' claim of contractual assurances. The fact that PG&E was receiving RMR compensation under the subsequently superceded "B" Contract fails to provide any legitimate basis for Southern Parties to conclude they were assured sunk cost recovery through RMR rates. The Commission never approved the "B" Contract, and in fact had expressed concern over the level of fixed cost recovery it provided, as well as expressly contemplating that it would be superceded. *See Pacific Gas and Electric Co., et al.*, 81 FERC ¶ 61,122, at pp. 61,555-56, 61,558 (1997). Moreover, while the "B" Contract provided sunk cost recovery, it also required all market revenues to be credited back to the ISO as an offset to that recovery. No such requirement was imposed on Southern Parties.[18] In addition, the Commission order approving transfer of the RMR units at issue required Southern Parties to assume the units' RMR obligations *subject to the outcome of this proceeding*. *See Pacific Gas and Electric Co., et al.*, 86 FERC ¶ 62,248, at p. 64,383 and n.16 (1999).

The April 2 Stipulation is equally unavailing to Southern Parties. Essentially, they conclude that because the April 2 Stipulation dispositively settles AFRR, and the settled AFRR subsumes sunk costs, sunk costs necessarily must be included in the FOP. This conclusion, however, is a *non sequitur*. It ignores the fact that Southern Parties may elect to operate their units under RMR Agreement Condition 2. Exh. JT-2, at pp. 19-20. In that event, they would be entitled to recover AFRR in full-- including sunk costs. It therefore was necessary to quantify AFRR in the April 2 Stipulation. But it does not follow that the April 2 Stipulation entitles Southern Parties to recover sunk costs via the FOP during RMR Agreement Condition 1 operations. In contrast to RMR Agreement Condition 2 operations, which preclude Southern Parties from retaining market revenues (*id.*, at pp. 41-42, 59-60) and therefore require sunk cost recovery from the ISO, operations under Condition 1 provide the opportunity for sunk cost recovery through market rates for energy/ancillary services. There is no inconsistency between the April 2 Stipulation and compensating Southern Parties' Condition 1 RMR obligations at net incremental cost.

6. Rulings Summary

I find and conclude that appropriate RMR compensation in a market-based rate scenario without revenue credits is an issue of first impression with potentially important policy implications. Accordingly, I find and conclude that in addition to case-specific rulings it is appropriate to make generic rulings on some of the issues addressed.

While I find that the availability payment component of RMR rates is intended to compensate the RMR unit owner for standing ready to provide energy/ancillary services if required by the ISO, I find and conclude that RMR obligations do not constitute a discrete product or service. Instead, I find and conclude that RMR obligations are local market power mitigation mechanisms which enable generators enjoying unique– and therefore essential– locations in the interconnected grid to participate in competitive markets for energy and ancillary services by mitigating those generators' ability to exploit local market power in limited circumstances. I also find and conclude that RMR obligations are a necessary condition precedent to Commission authority for RMR unit owners to charge market-based rates for energy/ancillary services provided by the units. I therefore find that RMR unit availability should be compensated in an economically transparent manner: appropriate compensation should mitigate local market power without unnecessarily advantaging/disadvantaging RMR unit participation in the competitive markets for energy and ancillary services. I find and conclude that net incremental cost compensation achieves these objectives provided that it covers all costs– including fixed costs, variable costs and reasonably identifiable opportunity costs– associated with RMR obligations. I also find that such compensation is consistent with the competitive/economically efficient electric industry paradigms implemented by the State of California and this Commission. Finally, I find that compensating RMR obligations at anything above net incremental cost: (1) would be inequitable to consumers; (2) would grant RMR unit owners a competitive advantage over other energy/ancillary service providers by subsidizing RMR unit owners' merchant operations; and (3) would reward the local market power that imposing RMR obligations is intended to mitigate.

In accordance with the preceding generic rulings, I find that the net incremental cost calculation methodology endorsed by Joint Parties, Staff, CPUC and EOB is the appropriate methodology under which to compensate Southern Parties' RMR obligations. I find that this methodology fully compensates Southern Parties for all costs– including fixed costs, variable costs and reasonably identifiable opportunity costs– associated with their RMR obligations. I find it would be inappropriate to add any incentive paymentto Southern Parties' RMR compensation for the reasons specified in Section C (I) (b) (4), *supra*.

II. What Shall Be the Means for Determining the Percentage Applied to the Approved Cost of a Capital Item to Yield the Surcharge Payment for that Item?

III. What Shall Be the Means for Determining the Percentage Applied to the Approved Cost of a Repair to Yield the ISO's Repair Share for that Repair?

Under the RMR Agreements, RMR unit owners may recover additional costs incurred for planned capital expenditures related to RMR obligations through a Monthly Surcharge Payment Factor ("MSPF"). Exh. JT-2, pp. 45-47. They also may recover unplanned repair expenses related to RMR obligations through a Repair Payment Factor ("RPF"). *Id.*, at pp. 47-52.

a. *Party Positions*

All parties favor linking these surcharge payment factors to the FOP. Exh. SOU-9, at p. 14; Exh. PGE-18, at p. 27-28; Exh. ISO-1, at p. 31; Exh. SCE-2, at pp. 63-66; Exh. SD-1, at p. 17; Exh. S-12, at p. 30; CPUC IB, at p. 23; EOB IB, at p. 22. There nevertheless is one point of disagreement[19] between the coalition favoring net incremental cost compensation and Southern Parties. The coalition argues that the ISO presumptively should pay no share of any economic RMR unit's (a unit covering going forward costs through market sales of energy/ancillary services) capital expenditures or repair costs because the unit owner would incur those costs irrespective of its RMR obligations.[20] Southern Parties counter that this presumption is inappropriate and that RMR unit owners should have the right to challenge any established MSPF or RPF if a capital improvement or repair would not have been made except for the RMR obligation.

b. *Discussion*

The MSPF and RPF logically should be consistent with the FOPF. Issues II and III therefore are decided in accordance with Issue I. The FOPFs derived in accordance with the ruling in Section C (I) (b) (3), *supra*, presumptively shall constitute the appropriate MSPFs and RPFs for Southern Parties' RMR units irrespective of economic viability. This ruling notwithstanding, both the ISO and Southern Parties shall be entitled to seek reasonable modification of the MSPF or RPF to be applied to any specific capital expenditure or repair cost as equity may require.

D. MATTERS NOT DISCUSSED

This Initial Decision's failure to discuss any matter raised by the parties, or any portion of the record, does not indicate that it has not been considered. Rather, any such matter(s) or portion(s) of the record has/have been determined to be meritless, immaterial or irrelevant. Arguments made on brief which were unsupported by record evidence or legal precedent have been accorded no weight.

E. ORDER

Wherefore, it is ordered, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that within thirty (30) days of the issuance of the Final Order of the Commission in this proceeding, the parties shall comply with the findings and conclusions contained in this Initial Decision, as adopted or modified by the Commission.

H. Peter Young
Presiding Administrative Law Judge

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[1]The parties joining in this Joint Stipulation are Southern Energy Delta, L.L.C., Southern Energy Potrero, L.L.C. (collectively, the "Southern Parties"), the California Independent System Operator Corporation ("ISO"), Pacific Gas and Electric Company ("PG&E"), San Diego Gas & Electric Company ("SDG&E"), Southern California Edison Company ("SCE"), the Public Utilities Commission of the State of California ("CPUC"), the California Electricity Oversight Board ("EOB"), and the Commission Trial Staff [("Staff")].

[2]*See also* the following CPUC Decisions: "Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation; Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation," Decision No. 95-12-063, (December 20, 1995), as modified by Decision No. 96-01-009, Rulemaking No. 94-04-031 (Filed April 20, 1994), Investigation No. 94-04-032 (Filed April 20, 1994), 1996 Cal. PUC LEXIS 28; 166 P.U.R. 4th 1, January 10, 1996; 1996 Cal. PUC LEXIS 22; 64 CPUC 2d 228, January 10, 1996.

[3]Many rates under these RMR Agreements were fixed by the terms of a settlement dated April 2, 1999, approved by the Commission on May 28, 1999. *California Independent*

System Operator Corp., 87 FERC ¶ 61,250 (1999). A copy of the April 1999 settlement has been admitted in this case as Exhibit JT1.

[4]*Pacific Gas and Electric Co.*, 81 FERC ¶ 61,122, at 61,557 (1997).

[5]On this same day, SCE and SDG&E also filed similar unexecuted, facility-specific Must-Run agreements.

[6]*Pacific Gas and Electric Co.*, 81 FERC ¶ 61,322, at 62,487 (1997).

[7]*Pacific Gas and Electric Co.*, 82 FERC ¶ 61,326 (1998).

[8]*California Independent System Operator Corp.*, 87 FERC ¶ 61,250 (1999).

[9]*Geysers Power Company, LLC*, 90 FERC ¶ 61,096 (2000).

[10]*Southern California Edison Company*, 90 FERC ¶ 61,091 (2000).

[11]*Pacific Gas and Electric Company*, 90 FERC ¶ 61,023 (2000).

[12]*Pacific Gas and Electric Company*, 90 FERC ¶ 61,049 (2000).

[13]*Duke Energy Moss Landing LLC, et al.*, 90 FERC ¶ 61,073 (2000).

[14]*Pacific Gas and Electric Co.*, 86 FERC ¶ 62,248 (1999).

[1]These figures correspond to the "Target Available Hours" reflected in Tables B-5 of the RMR Agreements, which reflect the maximum number of hours each unit must be prepared to respond to RMR calls from the ISO. Exh. JT-2, Schedules B, Tables B-5.

[2]These figures are based on historical data from April 1999 to September 1999. Exh. SOU-1, at pp. 26-31.

[3]Joint Parties is a coalition among the ISO, PG&E, SDG&E and SCE, all endorsing the same positions in these proceedings.

[4]On brief, however, Joint Parties endorse the additional incentive payment recommended by SCE Witness Joskow. Joint Parties IB, at p. 47 (referencing Exh. SCE-2, at pp. 10–11).

[5]Under the Staff proposal, any shortfall between a unit's "going forward" costs (costs which could be avoided by shutting down the unit) and estimated net market revenues would be compensated at the greater of net incremental cost or the shortfall amount.

[6]Assuming *arguendo* that RMR obligations fell within the traditional "capacity" rubric, that fact would not support Southern Parties' FOP calculation methodology or figures. The record confirms that Southern Parties' methodology relies on the maximum number of hours an RMR unit is available for dispatch. Exh. SOU-1, at pp. 19-24; Exh. SOU-4, at pp. 1-8; Exh. SOU-10, at pp. 17-18; Exh. S-12, at p. 15. By contrast, fixed capacity costs customarily are allocated based on customer contribution to peak demand. Exh. S-12, at pp. 17-18. *See also Southern California Edison Co.*, 26 FERC ¶ 63,098, at p. 65,322 (1984), *aff'd in relevant part*, 38 FERC ¶ 61,040, at p. 61,103 (1987). It follows that if RMR obligations constitute "capacity" service, the obligations properly should be priced like other demand charges. And since the record in these proceedings indicates that the ISO would not have to call on Southern Parties' RMR units up to 87.6% of system peak hours because the units already should be participating in the market (Exh. S-9), the demand charges for the units would be quite low-- far too low to support the 77% to 97% of RMR unit AFRR proposed by Southern Parties.

[7]Such "withholding" behavior would be rational and appropriate if a competitive market for RMR grid support existed because market forces ultimately would establish the appropriate price. By definition, however, RMR support is not competitive. In an otherwise competitive environment, this circumstance provides additional support for a conclusion that RMR obligations do not constitute a discrete product or service. It also undermines Southern Parties' attempt to characterize its ability to exploit local market power as location/scarcity rents. Exh. SOU-10, at p. 8; Exh. SOU-11, at pp. 11-12.

[8]The annual composite RMR unit AFRR which Southern Parties propose to recover through the FOP totals $120,199,621. Exh. SOU-1, at pp. 19, 44. Although Southern Parties concede that the $463 million acquisition premium paid for the RMR units must be recovered through the units' market-based rates for energy/ancillary services (Tr. 705-06 (referencing *Duke Energy Moss Landing, LLC, et al.*, 83 FERC ¶ 61,317 (1998))), they contend that the opportunity to do so depends on an adequate FOP. Tr. 706.

[9]In addition, this opportunity presumptively is more lucrative than the opportunity provided through traditional cost-based rates.

[10]Southern Parties' ability to elect Condition 2 status, moreover, obviates any potential for the "confiscation" which Southern Parties allege.

[11]Net incremental costs are the actual costs incurred by RMR unit owners as a result of RMR dispatches. Net incremental costs are calculated by subtracting any benefits that an RMR unit owner would not have realized in the absence of RMR dispatches from the total (gross) cost of the dispatches. Exh. PUC-1, at pp. 12-13.

[12]Contrary to Southern Parties' misleading characterization (Southern Parties IB, at p. 23), while net incremental cost compensation excludes *sunk* costs, it specifically subsumes *fixed* cost compensation. Exh. PGE-3, at p. 17.

[13]"Going forward" costs are the costs of keeping an uneconomic unit operating in the absence of RMR obligations. Rational actors in a competitive market would shut down any unit whose going forward costs exceeded net incremental cost compensation. Paying the RMR unit owner the difference between net incremental cost and going forward costs eliminates the economic incentive to shut down the unit, thereby preserving unit availability for RMR dispatch. The record indicates that only one of Southern Parties' Condition 1 RMR units (Potrero Unit 3) may require going forward cost compensation. Exh. PGE-5; Exh. PGE-11.

[14]The record indicates that two of Southern Parties' fifteen RMR units (Contra Costa Units 4 & 5) currently operate under Condition 2 due to the fact they do not generate electricity and there is no market for the voltage support the units provide. Exh. S-12, at p. 13; Exh. PGE-3, at p. 33. Statewide, only four RMR units (including Contra Costa Units 4 & 5) have elected Condition 2 operation to date. Exh. PGE-3, at pp. 32-33.

[15]Southern Parties were unable to identify any opportunity costs which Mr. Weingart failed to consider, apart from unsupported/unquantified claims that net incremental cost compensation: (1) deprives them of "location rents" (vs. local market power); and (2) that forbearance from electing RMR Agreement Condition 2 status represents an opportunity cost.

[16]It is similarly disingenuous to reward through a supplemental incentive payment the local market power that Joint Parties, Staff and EOB all argue RMR obligations are intended to mitigate.

[17]Dr. Joskow stated generally that his ten percent (10%) quantifier is consistent with "Commission precedent," but provided no specific references or citations. Tr. 984-85. Although Staff witness Sammon specifically cited *Middle South Energy, Inc.*, 31 FERC ¶ 61,305, pp. 61,660-62 (1985), and *Panhandle Eastern Pipe Line Co.*, 64 FERC ¶ 61,009, at p. 61,049 (1993), to support the "uncertainty" justification for his ten percent (10%) quantifier (Exh. S-1, at pp. 30-32), my review of those decisions indicates that they provide inadequate support for Staff's quantifier in this case. Moreover, the record indicates that Staff over-emphasizes the difficulty of estimating RMR unit net incremental costs. Exh. PGE-3; Exh. PGE-6; Exh. PGE-7; Exh. PGE-8; Exh. PGE-9; Exh. PGE-13; Exh. PGE-14; Exh. PGE-15; Exh. PGE-16; Exh. PGE-21 (corrected); Exh. PGE-22. Joint Parties and Staff also fail to explain how adding an incentive payment to an "uncertain" underlying net incremental cost calculation makes the underlying

calculation any more reliable. Merely increasing an uncertain estimate's magnitude ignores the fact that margin of error operates in two directions.

[18]The market revenue credit requirement also distinguishes other *current* RMR generators, including PG&E, from Southern Parties.

[19]Southern Parties also claim that sunk costs should be reflected in the MSPF and RPF. Exh. SOU-9, at pp. 16-17. In addition, Staff proposes to supplement Southern Parties' MSPF and RPF by ten percent (10%) in accordance with Staff's FOP incentive payment proposal. Exh. S-12, at p. 30. Neither sunk costs nor an incentive payment appropriately is reflected in the FOP; they therefore must be excluded from the MSPF and RPF as well.

[20]The coalition would apply the net incremental cost FOPF to a non-economic unit's capital expenditures and repair costs. Exh. PGE-3, at pp. 39-41.