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MAIL DATE
2/11/97

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Decision 97-02-021 February 5, 1997

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	R.94-04-031 (Filed April 20, 1994)
Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation.	I.94-04-032 (Filed April 20, 1994)

ORDER MODIFYING AND DENYING REHEARING OF DECISION 95-12-063 AS MODIFIED BY DECISION 96-01-009

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I. INTRODUCTION

On January 10, 1996, the Commission issued Decision (D.) 95-12-063 as modified by D.96-01-009 ("Preferred Policy Decision"), which articulated our vision of a competitive framework for the electric services industry in California, and presented our preferred policy choices for its restructuring. This decision was the culmination in policy terms of a process we began in April 1992, which led to a joint rulemaking and investigation,[1] to review comprehensively current and future trends in this industry.

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1. Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation, Etc. ("Electric Restructuring OIR/OII" or "Blue Book"), R.94-04-031 and I.94-04-032.

Eight applications for rehearing of the Preferred Policy Decision were timely filed, by Toward Utility Rate Normalization ("TURN"); Pacific Gas and Electric Company ("PG&E"); Southern California Edison Company ("Edison"); jointly, Agricultural Energy Consumers Association, California Manufacturers Association, California Industrial Users, Destec Power Services, Inc., Enron Capital & Trade Resources, Illinova Power Marketing, Inc., and Mock Resources, Inc. ("Joint Applicants I"); jointly, Enron Capital & Trade Resources, Destec Power Services, Inc., Illinova Power Marketing, Inc., Mock Resources, Inc., and the California Retailers Association ("Joint Applicants II"); Agricultural Energy Consumers Association ("AECA"); Coalition of California Utility Employees ("CCUE"); and Energy Producers and Users Coalition ("EPUC"). These parties represent virtually every group of stakeholders involved in our electric restructuring proceeding.

Ten parties filed responses to the applications for rehearing: the Division of Ratepayer Advocates ("DRA"); Edison; San Diego Gas & Electric Company ("SDG&E"); PG&E; California Farm Bureau; Electric Clearinghouse, Inc.; TURN; California Department of General Services; and jointly, California Manufacturers Association ("CMA") and California Large Energy Consumers Association ("CLECA"), who filed two separate responses, one to PG&E's application and one to Edison's.

Applicants contend that the Preferred Policy Decision, in various particulars, is preempted by federal law and/or violates the Commerce Clause of the U.S. Constitution; constitutes a taking of utilities' property without just compensation; was arrived at without proper notice to parties or necessary evidentiary hearings; is not based on an adequate record or findings of fact and is therefore arbitrary and capricious; is inconsistent with prior Commission decisions; and is in violation of the California Environmental Quality Act ("CEQA").

Several other events relevant to our resolution of these applications for rehearing occurred subsequent to their filing. On March 14, 1996, we issued our initial Roadmap Decision,[2] which set in motion the preliminary stages of implementation. In August the Legislature passed Assembly Bill 1890 ("AB 1890"), Stats. 1996, Ch. 854, and on September 23, 1996, the Governor signed it. This new law determined that California's electric utility industry should be restructured, and established basic ground rules for operation of the restructured industry. AB 1890 resolved many of the issues addressed in our Preferred Policy Decision, some receiving different treatment from what we had proposed. On September 30, the Coordinating Commissioner issued a ruling ("CCR") requesting, among other things, additional information on certain of the issues raised in several of the applications for rehearing and questions relating to AB 1890. On October 30, November 26, and December 18, the Federal Energy Regulatory Commission ("FERC") issued three important orders[3] related to filings the utilities had made before that agency in compliance with the Preferred Policy Decision. On December 23, we issued our AB 1890/CEQA

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2. Order Instituting Rulemaking and Order Instituting Investigation on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation ("Roadmap Decision") [D.96-03-022] (1996) __ Cal.P.U.C.2d __.

3. Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company ("Order Granting Petition for Declaratory Order In Part") (October 30, 1996) 77 F.E.R.C. ¶61,077; Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company ("Order Conditionally Authorizing Establishment of an Independent System Operator and Power Exchange, Conditionally Authorizing Transfer of Facilities to An Independent System Operator, and Providing Guidance") (November 26, 1996) 77 F.E.R.C. ¶61,204; Pacific Gas and Electric Company, San Diego Gas & Electric Company and Southern California Edison Company ("Order Providing Guidance and Convening A Technical Conference") (December 18, 1996) 77 F.E.R.C. ¶61,265.

Decision.[4] Finally, on that same date we issued our Roadmap II Decision,[5] which reassessed the status of the restructuring of the electric industry following the passage of AB 1890, and continued the job of delineating its implementation.

We have carefully reviewed each and every allegation of error raised in the applications for rehearing, including in our review an assessment of these allegations, to the extent appropriate, in the context of all of the events recited above. We conclude that several of the allegations have been rendered moot by AB 1890 and in this respect, the applications for rehearing identify no error. As to those allegations not made moot, we find them without merit. Thus none of the allegations raised has presented adequate justification for granting rehearing of our Preferred Policy Decision, and we will deny rehearing of that decision. In certain limited areas, however, we will modify, for purposes of clarification, the Preferred Policy Decision as indicated below.

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4. Interim Opinion and Order Addressing California Environmental Quality Act Matters ("AB 1890/CEQA Decision") [D.96-12-075] (1996) __ Cal.P.U.C.2d __.

5. Order Instituting Rulemaking on the Commission's Proposed Policies Governing Restructuring California's Electric Services Industry and Reforming Regulation ("Roadmap II Decision") [D.96-12-088] (1996) __ Cal.P.U.C.2d __.

II. FEDERAL PREEMPTION AND THE COMMERCE CLAUSE

A. Commission Jurisdiction Over Retail Wheeling.

A key element of our Preferred Policy Decision was that the utilities allow their customers access to alternative generation providers. See, for example, Ordering Paragraphs Nos. 6, 9, 10, and 12.[6]

A primary issue raised by the two utilities appealing the Preferred Policy Decision is whether the Federal Power Act ("FPA") (16 U.S.C. §824a, et seq.) prohibits state regulators from ordering utilities to provide their retail customers with direct access to competitive sources of power. Both PG&E and Edison take the position that the FPA does prohibit the Commission from ordering direct access.

PG&E argues that because the utilities will have to file retail transmission tariffs at the FERC in order to comply with the above directives, the Preferred Policy Decision is tantamount to an order directing the timing and content of a FERC-jurisdictional service and is thus preempted. PG&E further argues that since retail transmission is no different from wholesale transmission for purposes of jurisdiction, any attempt on the part of this Commission to order retail direct access is preempted by the FPA, regardless of the 1992 amendments to that Act. Edison also argues the Commission is preempted from ordering direct access, and incorporates by reference section III.3 of its January 31, 1995 brief to this Commission addressing the direct access issue.

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6. We note that AB 1890 also mandates direct access. Unlike certain other issues raised by the rehearing applicants which are discussed below, the fact that AB 1890 has codified this requirement does not moot the issue, because direct access is challenged on federal preemption grounds.

The question of whether, under federal law, a state may order an electric utility to provide direct access for retail customers is a question of first impression. Opponents of retail wheeling contend that the FPA preempts states from ordering retail wheeling, because Section 201(a) of the FPA makes federal jurisdiction over wholesale sales and interstate transmission "plenary," and thereby precludes states from regulating in those areas except where Congress explicitly granted authority to the states. (Federal Power Comm'n. v. Southern California Edison Co. ("Colton") (1964) 376 U.S. 205, 215-216.) Supporters of retail wheeling contend that the states retain jurisdiction to order direct access, because Congress never intended that the federal government occupy the field of retail sale and delivery of electricity to retail customers.

While we have recognized, both in Electric Restructuring OIR/OII and our Preferred Policy Decision, that the Energy Policy Act of 1992 ("EPAct") (Pub.L. No. 102-486 (October 24, 1992) 106 Stat. 2776, 1992 U.S. Code Cong. & Admin. News 1953) does not clarify all the boundaries of federal and state jurisdiction, no federal law or legislative history provides evidence of federal intent to preempt state retail wheeling orders. Accordingly, it is our opinion that under federal law, a state regulatory authority does have the requisite authority to order retail direct access.

All indications are that this primary jurisdictional issue has been eliminated. PG&E, Edison, and SDG&E have made the filings at the FERC requested by this Commission, and they include a direct access component. The FERC has preliminarily approved those filings. In another context, these utilities have indicated to the FERC that it need not reach the merits of a preemption argument raised by several parties to the FERC proceedings because these utilities currently intend to abide by our Preferred Policy Decision. (Order Providing Guidance and Convening a Technical Conference, supra, 77 F.E.R.C. ¶61,265, at pp. 29-30 (mimeo).) However, we believe it prudent nonetheless to outline the basis for our position that we have the authority to order retail direct access.

1. Federal Statutory Law Does Not Preempt State Direct Access Orders.

a) The Federal Power Act prior to EPAct amendments does not explicitly or implicitly preempt state authority over retail wheeling.

Under the Supremacy Clause of the U.S. Constitution, Congress may preempt state authority either explicitly or implicitly. (U.S. Const. art. VI, cl. 2.) The FPA contains no explicit preemption of state authority over retail wheeling. Absent explicit statutory preemption, implicit preemption may be evidenced by congressional intent. As the following discussion will show, there is also no evidence of implicit preemption of such state authority.

The FPA was enacted in 1935, to close the "regulatory gap" created by the United States Supreme Court's invalidation of state regulation of interstate wholesale sales in the landmark case of Public Utilities Comm'n v. Attleboro Steam & Elec. Co. ("Attleboro") (1927) 273 U.S. 83.[7] The FPA established federal jurisdiction over certain electric utility transactions and created the Federal Power Commission ("FPC", now FERC).

Federal regulatory authority established by the FPA is limited in several important ways. First, federal jurisdiction over sales is limited to wholesale sales. Secondly, federal jurisdiction is limited to transmission and wholesale sales in

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7. The Attleboro case involved an attempt by the Rhode Island Public Utilities Commission to regulate the rates at which a Rhode Island utility sold electricity to an electric utility located in Massachusetts. The U.S. Supreme Court struck down Rhode Island's regulation, ruling that it imposed a burden on interstate commerce which was impermissible under the Commerce Clause. (Id.)

interstate commerce.[8] Finally, federal jurisdiction over facilities does not extend, except as specifically provided, to facilities used for generation or local distribution.

The FPA expressly leaves to state regulation the local distribution and intrastate transmission of electricity. (16 U.S.C. §824b.) The FPA also states that federal regulation extends "only to those matters which are not subject to regulation by the States" (16 U.S.C. §824a), thus providing further evidence that Congress intended the states to play a role in the regulation of electric services. Although the U.S. Supreme Court has indicated that this language does not provide an independent basis for limiting federal jurisdiction (Colton, supra, 376 U.S. at p. 215), it does demonstrate Congress' intent to preserve certain areas concerning the sale and delivery of electric energy for state regulation and not to preempt them.

b) The field of transmission in interstate commerce does not include direct access for retail customers.

In the absence of explicit preemption, Congressional intent to occupy a field may be found: (i) where the federal statutory regulation is so pervasive as to leave no room for the states to supplement it; (ii) where the federal interest is so dominant that state regulation is precluded, or (iii) where "the object sought to be obtained by the federal law and character of obligations imposed by it may reveal the same purpose." (Fidelity Federal Sav. & Loan Ass'n v. De La Cuesta (1982) 458 U.S. 141, 153 (internal quotation marks omitted).)

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8. The FERC has asserted jurisdiction over transmission using facilities that are interconnected to a multistate grid, regardless of whether the so-called "contract path" is solely within one state.

Section 201(a) of the FPA contains a general statement of "plenary" federal jurisdiction over transmission in interstate commerce. It forms the basis for the argument presented by parties opposing state jurisdiction over retail direct access that the FPA "occupies the field" with respect to regulation of such transmission. However, we do not believe that Congress, in enacting the FPA, ever considered the question of direct access for retail customers. As the Department of Energy has pointed out, the precise boundaries of the preempted field are critical to this analysis:

> In particular, does the field occupied by this plenary jurisdiction extend to all regulatory matters concerning transmission in interstate commerce, including areas such as ordering wheeling where the Federal regulatory authority is expressly limited by the FPA? The FPA as originally enacted did not provide Federal regulators with general authority to order a utility to provide either wholesale or retail transmission services, and so it may be argued that ordering of wheeling was not an area that was preempted.[9]

(Brief of the United States Department of Energy, filed January 31, 1995, pp. 12-13.)

Even prior to the enactment of the FPA, the states had divided the retail market into franchised service territories, pursuant to state statutes and regulatory commission orders. States have regulated the field of bundled retail sales, including delivery service, since regulation of electric utilities began. In 1935, when the FPA was enacted, states were regulating transmission to end-users as part of setting the bundled retail rate. In enacting the FPA, Congress did not

9. The FPA does provide federal authority to order wheeling in emergency situations. (16 U.S.C. §824a, subd. (c).)

intend to preempt the states from regulating matters of traditional state retail franchises. Rather, the FPA was passed to close the regulatory gap created by the Attleboro case, supra, which held that states possess no jurisdiction to set rates for wholesale sales.

The FPA's explicit grant of authority to the states over local distribution and intrastate transmission further indicates that Congress did not intend to occupy the field with respect to the transmission and distribution of electricity to retail customers. Despite the broad federal role in interstate transmission of electricity, the statutory scheme established in the FPA leaves room for state-mandated direct access. This conclusion comports with the traditional role of state regulation dealing with all aspects of the retail distribution of energy, an eminently local matter. (Arkansas Elec. Coop. v. Arkansas Pub. Serv. Comm'n (1982) 461 U.S. 375, 377, holding that "[t]he regulation of utilities is one of the most important of the functions traditionally associated with the police power of the States".)

State authority over supply of electricity to retail customers is properly viewed as a matter of state retail franchise law. Historically, states have had a pervasive and unchallenged role in regulating the transmission of electricity to ultimate customers as part of bundled retail rates. Since the inception of state regulation of public utilities, regulation of the rates, terms and conditions of retail electric service provided by a utility to ultimate consumers located within its service territory has been a matter of state jurisdiction.

A state's ability to certificate utilities to serve a retail franchise inherently must include the authority to redefine the parameters of franchised electric service, including the authority to require that utilities provide customers access to competitors. There is no evidence that Congress, in enacting the FPA or its subsequent amendments, intended to limit a state's ability to allow competition within the retail franchise.

c) Amendments to the FPA in EPAct do not preempt state authority over retail wheeling.

In 1978, the enactment of the Public Utility Regulatory Policies Act ("PURPA") amended the FPA to give the FERC very limited authority to order wholesale wheeling, and expressly barred retail wheeling orders. (16 U.S.C. §824j.) With the passage of EPAct in 1992, Congress provided the FERC with greatly expanded power to order wholesale wheeling. (See Section 211 of the FPA, 16 U.S.C. §824.) However, in granting this new authority, Congress again prohibited the FERC from ordering retail wheeling. (See Section 212(h)(1) of the FPA, 16 U.S.C. §824k, subd. (h)(1).)

EPAct also contained a savings clause which states:

> "Nothing in this subsection shall affect any authority of any State or local government under State law concerning the transmission of electric energy directly to an ultimate consumer." (16 U.S.C. §824k, subd. (h).)

Parties are divided over the meaning of the EPAct amendments. Opponents of state authority to order retail wheeling argue that the restrictions in EPAct reflect an intent to narrow the scope of the field occupied by the FPA. Proponents of state retail wheeling authority assert that the savings clause is an indication of congressional intent to leave the issue of retail wheeling to the states.

The Joint Explanatory Statement of the Committee of Conference which accompanied EPAct explains:

> "New [S]ection 212(h) . . . contains a savings clause for state laws dealing with retail wheeling. Thus, State laws that either prohibit or permit retail wheeling are unaffect[ed] by this subsection. And, <u>if otherwise valid</u> [these state laws] remain in full force and effect.

(113 Cong. Rec. H12157 91992 (emphasis added).)[10] This language suggests that Congress' intent in adding the savings clause was to leave the field of retail wheeling unoccupied and to ensure that the validity of state law on retail wheeling would not be adversely affected by the passage of EPAct.

Clearly, Congress has not expressly prohibited the states from ordering retail wheeling, as it did with the FERC in Section 212(h) of the FPA. As to whether the prohibition on FERC-ordered retail wheeling implicitly prohibits states from ordering retail wheeling, this is best answered in the negative by the language of the savings clause itself.

2. No Conflict Exists Between a State Mandated Retail Access Order and Federal Regulation of Transmission and Wholesale Sale of Electricity in Interstate Commerce.

A state law will be found to conflict with federal law if: (i) it is physically impossible to comply with both state and federal law, or (ii) the state law stands as an obstacle to the accomplishment of the full purposes and objectives of Congress. (Silkwood v. Kerr-McGee Corp. (1984) 464 U.S. 238, 248.)

No actual conflict exists between state-mandated direct access and federal regulation of the transmission and wholesale sale of electricity in interstate commerce. A utility may distribute power on behalf of an ultimate consumer, either voluntarily or pursuant to state order, while fully complying with applicable federal regulations. Moreover, state-mandated direct access does not in and of itself interfere with the federal objective of providing rates, charges, terms, and conditions for transmission service that are just and reasonable, and not unduly discriminatory. (See 16 U.S.C. §824d.) Finally,

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10. H.R. Conf. Rep. No. 102-1018, 2d Sess., p. 388 (1992), reprinted in 1992 U.S. Code Cong. & Admin. News 2472, 2479.

the savings clause provides persuasive evidence that Congress meant to preclude preemption challenges to state retail wheeling orders based on arguments that such state orders conflict with Section 212(h), which prohibits the FERC from ordering retail wheeling.

The FERC itself, in its recent MegaNOPR order, explicitly did not take a position on the issue of retail wheeling, other than to say that it lacks the jurisdiction to issue such an order. It stated, at pages 431-432 of that order:

> "In asserting jurisdiction over unbundled retail transmission in interstate commerce by public utilities, [FERC] in no way is asserting jurisdiction to order retail transmission directly to an ultimate consumer. Section 212(h) clearly prohibits us from doing so. In addition, as stated in both the initial Stranded Cost NOPR and the Open Access NOPR, we do not address whether states have authority to order retail wheeling in interstate commerce. [FERC's] assertion of jurisdiction is that <u>if</u> retail transmission in interstate commerce by a public utility occurs voluntarily or as a result of a state retail wheeling program, [FERC] has exclusive jurisdiction over the rates, terms and conditions of such transmission and public utilities offering such transmission must comply with the FPA by filing proposed rate schedules under section 205. ¶[FERC] clarifies that nothing in this jurisdictional determination changes historical state franchise areas or interferes with state laws governing retail marketing areas of electric utilities."

(<u>Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs Etc</u>. ("<u>Order No. 888</u>") (April 24, 1996) III F.E.R.C. Stats. & Regs. ¶31,036.)

The fact that the FERC cannot order retail wheeling greatly reduces the possibility of conflict with a state retail wheeling order. A Commission order requiring a California utility to transmit electricity to a consumer would not in any way affect either the rates or the terms and conditions of the transmission itself, the areas subject to FERC jurisdiction. In fact, our Preferred Policy Decision required the California utilities to comply with all applicable federal requirements, including preparing and filing tariffs that comply with the FERC's asserted jurisdiction over the rates, terms and conditions of unbundled retail transmission.

B. The Mandatory Buy-Sell Requirement and Preemption.

Our Preferred Policy Decision stated that:

> "For the five-year transition period during which PG&E, SCE and SDG&E seek recovery of their stranded generation assets and power purchase liabilities, each utility shall bid all of its generation into the Power Exchange and procure electric energy for its full service customers by purchases from the Power Exchange. During the transition period, any generation unit sold by the utilities by way of divestiture to a non-affiliated new owner shall immediately be freed of any obligation to bid into the Power Exchange. At the end of the transition period, when determination of assets which qualify for recovery under the competition transition charge has been finalized, the utilities shall be released from any mandatory requirement to bid into or purchase from the Power Exchange."

(Preferred Policy Decision, pp. 219-220 (Ordering Paragraph No. 5) (mimeo); see also, p. 205 (Conclusion of Law No. 18) (mimeo).) This arrangement has been referred to by various parties as the "mandatory buy-sell requirement."

Joint Applicants II argue that this is a prohibition on all other forms of wholesale sales by California utilities which in effect amounts to an attempt to mandate rates, terms or conditions of wholesale sales, an area which the FERC has in no uncertain terms stated is within its sole jurisdiction. Joint Applicants I contend similarly that by foreclosing the California utilities from participating in interstate transactions which are currently permitted, we have impermissibly mandated the timing and content of future rate filings. Joint Applicants I acknowledge the wisdom of our seeking the cooperation of the FERC, but argue that the immediate and direct impact of the mandatory buy-sell requirement "places the Commission in the posture of openly challenging the FERC's authority." (Joint Applicants I's Application for Rehearing, p. 24.)

We reject these contentions. The Preferred Policy Decision set forth principles of market structure which the Commission believed would achieve its preferred policy goals. Principles are not equivalent to rates, terms, and conditions of service, nor do principles dictate the timing and content of any necessary FERC filings. The Preferred Policy Decision explicitly recognized that the FERC has sole jurisdiction over both the Independent System Operator ("ISO") and the Power Exchange ("PX"), and over the rates, terms, and conditions of service under which both of these entities will operate. While we also called for the California electric utilities to make all the filings the FERC requires in connection with seeking that agency's approval of our preferred market structure, this is very different from dictating the terms of those filings. Finally, we note that in its December 18 order, the FERC has concluded that the mandatory buy-sell requirement as an element of California's restructuring program is consistent with the FPA. (Order Providing Guidance and Convening A Technical Conference, <u>supra</u>, 77 F.E.R.C. ¶61,265, at pp. 32-33 (mimeo).)

C. Commission Jurisdiction Over Filings at the FERC.

PG&E and Joint Applicants II argue that the Commission can neither order the utilities to make particular filings at the FERC, nor dictate the terms of those filings. Both parties argue that is exactly what the Commission did in ordering the utilities to file with the FERC for authority to establish the ISO and the

PX, and in basically setting forth what those filings should contain. PG&E contends the Commission by doing so attempts to prescribe the terms and conditions of the services which both the ISO and PX are supposed to provide by requiring conformance to the Commission's decision in the FERC filings. But, PG&E argues, the FPA preempts the Commission from requiring that the ISO and PX filings be made, and from trying to impose terms and conditions on those filings. Joint Applicants II make largely the same argument.

PG&E states that it is undisputed that the functions of the ISO and PX will be exclusively subject to the FERC's jurisdiction. PG&E then contends that the federal courts have held that states have no power to order that such FERC-jurisdictional filings be made. PG&E cites Commonwealth of Massachusetts Department of Public Utilities v. FERC (1st Cir. 1984) 729 F.2d 886, upholding Western Massachusetts Electric Company (1983) 23 F.E.R.C. ¶61,025. Joint Applicants II further cite Wisconsin Electric Power Co. (1993) 62 F.E.R.C. ¶61,142, p. 62,007, where the FERC rejected attempts by a state commission to develop and apply transmission policy to FERC jurisdictional transmission. Joint Applicants II request that the Commission modify its Preferred Policy Decision to make its policy preferences concerning the ISO and PX "recommendations" to the FERC.

Our Preferred Policy Decision did not dispute the FERC's jurisdiction over both the ISO and the PX; in fact, it explicitly acknowledged that jurisdiction. We also recognized that the FERC possesses exclusive authority to approve, disapprove or modify the proposed terms, conditions and prices of pool wholesale sales and interstate transmission services. (See FERC Policy Statement Regarding Regional Transmission Groups 58 Fed.Reg. 41626-41633 (Aug. 5, 1993).) As we have already stated, we reject any argument that because the filings we seek relate to

FERC-jurisdictional entities, they equate to filings of FERC-jurisdictional terms, conditions and pricing of sales for resale or interstate transmission services.

Both parties correctly note that the FERC has rejected public utility filings ordered by a state regulatory agency seeking to change FERC-jurisdictional rates. However, the decisions cited by applicants are distinguishable from the present circumstances. In this case, we have adopted principles; we have not ordered that particular rates be filed. The California utilities have gone forward and made the FERC filings required by the Commission. The FERC has accepted them for review, and has preliminarily approved them. Moreover, the FERC has indicated a strong willingness to engage in cooperative efforts with this Commission in the course of our restructuring efforts. (See Order No. 888, supra, at p. 429 (mimeo).)

Nonetheless, to remedy several inconsistencies within the Preferred Policy Decision, as well as to provide complete assurance that we in no way intended to usurp any aspect of FERC jurisdiction, we will modify the Preferred Policy Decision to state that we request and authorize the utilities to make the ISO and PX filings with the FERC, using for guidance the principles discussed in the Preferred Policy Decision.

D. The Mandatory Buy-Sell Requirement and the Commerce Clause.

As quoted specifically above, the Preferred Policy Decision required that California utilities buy and sell power exclusively through the PX until the end of the five-year transition period, when determination of assets which qualify for recovery under the CTC will have been finalized. Conclusion of Law No. 21 reiterated the Commission's position, fully discussed in the Preferred Policy Decision, that "allowing jurisdictional utilities to opt for non-Exchange purchases and sales during the transition period disguises pricing information, limits customer choice, and requires contentious regulatory proceedings to validate the dimension and legitimacy of the competition transition charge." (Preferred Policy Decision, p. 206 (mimeo).) The Preferred Policy Decision also called for the utilities to plan for voluntary divestiture through spin-off or outright sale; as generation units are divested, they are freed from their obligation to bid into the PX. (Preferred Policy Decision, pp. 52 & 223-224 (Ordering Paragraph No. 19) (mimeo).)

The CCR asked parties to comment on the impacts, if any, of AB 1890 on the mandatory buy-sell requirement, as well as to provide additional detailed information supporting the benefits and detriments to California ratepayers of this requirement. Most commenting parties supported continuation of the requirement; all concluded that the requirement is not directly addressed by AB 1890, and is not in conflict with this legislation. In our Roadmap II Decision, we agreed. We also stated in that decision that we would not discuss the legal issues raised by the commenting parties, as we were not addressing the applications for rehearing at that time. It is now appropriate to address these issues.[11]

1. Positions of the Parties.

The mandatory buy-sell aspect of the Commission's decision is attacked by several parties as being in violation of the Commerce Clause of the U.S. Constitution. PG&E argues the profound impact that the ISO/PX arrangement would have on electric systems throughout the western region will create an

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11. We note that with the exception of PG&E, those commenting parties that had filed applications for rehearing on this issue did not change their positions in their comments to the CCR. PG&E had opposed the mandatory buy-sell requirement in its application for rehearing, but basically supported the requirement in its comments, although it did propose three modifications to it, which we did not address in the Roadmap II Decision and do not address herein.

enormous burden on interstate commerce, a burden which has not been justified in light of the putative local benefits to be realized. PG&E also argues that the requirement that utilities direct their generation exclusively to the PX puts a further burden on interstate commerce by cutting the utilities off from the opportunity to participate as sellers in the northwest and southwest power markets for economy energy and other peak sales. PG&E contends this not only violates the Commerce Clause, but Section 202 of the Public Utilities Code as well.[12]

PG&E asserts that the Commission lacks authority to preclude it from selling into any spot markets any surplus energy not otherwise needed to fulfill the requirements of its customers. Even if the Commission can justify its requirement that generation be initially offered only to the PX by the local benefits, PG&E argues that once its tendered generation is refused by the PX, it must be free to market that power elsewhere in interstate commerce. (PG&E's Application for Rehearing, p. 35.) We note that PG&E's entire Commerce Clause argument is slightly over one page long, and contains virtually no supporting legal authority.

Joint Applicants I also argue that "the CPUC's mandate of Power Exchange purchases and sales runs afoul of the commerce clause of the Constitution by creating an undue burden on interstate commerce." (Joint Applicants I's Application for Rehearing, p. 22). They state that this "mandate" would directly prohibit interstate transactions that are presently permitted, thus effectively putting an "embargo" on interstate commerce which amounts to an undue burden. While they do not cite any

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12. Section 202 provides, in pertinent part: "Neither this part [the Public Utilities Act] nor any provision thereof, except when specifically so stated, shall apply . . . to interstate commerce, except insofar as such application is permitted under the Constitution and laws of the United States. . . ."

court cases, they do cite one FERC decision which they allege supports their argument. (Joint Applicants I's Application for Rehearing, pp. 22-23). They further contend that the mandatory buy-sell requirement is poor public policy because it would disrupt a highly efficient existing regional market for power, and that the record does not contain evidence sufficient to support the conclusion that the mandatory buy-sell requirement is reasonable. (Joint Applicants I's Application for Rehearing, p. 4.)

DRA agrees that this requirement violates the Commerce Clause by placing a significant burden on interstate commerce. DRA contends the Preferred Policy Decision fails to identify a compelling local interest, fails to create a record that the buy-sell restriction would solve the local problem, and fails to adequately review alternative and less burdensome means to protect the local interest. (DRA's Response, pp. 3-5.) Electric Clearinghouse has echoed these concerns. (See Electric Clearinghouse, Inc.'s Response, p. 5.)

On the other side of these arguments, CMA and CLECA call PG&E's Commerce Clause claim "specious," and argue that states have the authority to restructure and revamp their regulated monopolies. (CMA/CLECA's Joint Response, pp. 16-17.) SDG&E contends that Joint Applicants I are presenting arguments which are not only wrong, but are in marked contrast to the positions they have taken in other comments in this proceeding. (SDG&E's Response, pp. 8-9, and fns. 13 & 14.) SDG&E disputes the argument that utility participation in the regional markets is barred by the decision, arguing that all of the power currently available to the market will remain available. SDG&E also disputes the contention that "economy energy" imports will be substantially reduced, on what SDG&E concludes is the apparent and unfounded assumption that "no one will offer to sell into the California market if it has a transparent spot market, as would be established by the Power Exchange." SDG&E finally takes issue with the argument that retailers and wholesalers will be barred from participating in long, medium and short-term markets, stating that "[n]othing precludes any such deals from taking place except that utilities may not enter into self-dealing transaction [sic]." (SDG&E's Response, pp. 8-11.)

2. The Mandatory Buy-Sell Provision Does Not Discriminate Against Out-of-State Entities.

The U.S. Supreme Court has established two approaches to determining if a state regulation violates the Commerce Clause. If the statute discriminates on its face by giving economic protection to in-state entities at the expense of out-of-state entities, then it is deemed virtually per se invalid and can be justified only by a compelling state interest. (City of Philadelphia v. New Jersey (1978) 437 U.S. 617.) If a statute is not discriminatory on its face, but regulates evenhandedly to effectuate a legitimate local public interest and only affects interstate commerce incidentally, then the Court will balance the incidental burdens imposed on commerce against the benefits to local interests provided by the statute. (Id. at p. 624, citing Pike v. Bruce Church (1970) 397 U.S. 137. See also, Arkansas Elec. Coop. v. Arkansas Pub. Serv. Comm'n, supra, 461 U.S. at pp. 393-394, citing Pike v. Bruce Church, supra.)

The mandatory buy-sell provision regulates evenhandedly; it does not discriminate against out-of-state buyers or sellers. Indeed, we note that part of the complaint is that out-of-state sellers and unregulated in-state sellers will have a competitive advantage over regulated utilities. (Electric Clearinghouse, Inc.'s Response, p. 3.) Buyers and sellers in the regional power markets will not be denied the opportunity to buy from investor-owned utilities under the Commission's jurisdiction. Those utilities must bid into the PX, but regional buyers are free to come into the PX to buy energy for resale. (Preferred Policy Decision, pp. 50 & 61 (mimeo).) If prices in the PX are competitive, it should be attractive for regional buyers to enter the PX market; out-of-state consumers will be free to buy through the PX on the same terms as in-state consumers.

In like measure, the Preferred Policy Decision required California utilities, during the period they would be seeking to recover stranded asset costs, to bid all of their generation into the PX regardless of whether the power would be used locally or shipped out of state. These utilities were also required to procure electric energy for full service customers by purchases from the PX, regardless of whether the power was produced in-state or out-of-state. This requirement was applied uniformly and exclusively to utilities seeking recovery of their stranded generation assets and power purchase liabilities. Both out-of-state entities, and other California entities (such as municipal systems) were outside the scope of this requirement.[13]

Because the mandatory buy-sell provision does not discriminate against out-of-state players, the balancing approach which was developed in Bruce Church would therefore be applied by a court. The relevant inquiry thus becomes the extent of the burden on interstate commerce, balanced against the local benefits we have identified. The extent of the burden that will be tolerated will depend on the nature of the local interest involved, and on whether it could be promoted as well with a lesser impact on interstate commerce. (Arkansas Elec. Coop. v. Arkansas Pub. Serv. Comm'n, supra, 461 U.S. at p. 394, citing

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13. The Supreme Court has also held that states cannot require that residents be given a preferred right of access over out-of-state consumers to natural resources located within a state. (New England Power Co. v. New Hampshire, et al. (1982) 455 U.S. 331 (holding that state law prohibiting exportation of hydroelectric generation violates the Commerce Clause).) However, the Preferred Policy Decision does not prohibit the export of electricity. It is true that under the mandatory buy-sell arrangement, the regulated utilities will be temporarily denied the ability to directly sell power into regional power markets; however, electricity will continue to be exported through participation by out-of-state consumers in the PX.

<u>Pike v. Bruce Church</u>, <u>supra</u>.) However, if the local interest can be shown to be great enough, the fact that other methods or mechanisms might have conceivably worked will not be enough to destroy the decision. (See <u>Maine v. Taylor</u> (1986) 477 U.S. 131.)

3. The Local Benefits Outweigh Any Burdens.

We first note that except in cases of per se discrimination, a "compelling" local interest is not required; rather, the test is whether legitimate local interests outweigh the effects on interstate commerce. The Preferred Policy Decision set forth several legitimate concerns underlying the five-year buy-sell requirement. This requirement addressed the concerns that pricing information would be disguised during the transition period, that customer choice would be limited, and that contentious regulatory proceedings would otherwise be necessary to validate the dimension and legitimacy of the CTC. (Preferred Policy Decision, pp. 58-60 (Conclusion of Law No. 21) (mimeo).) These concerns are not merely cover for economic protection measures. In particular, the need to be able to monitor utility transactions to validate the dimension and legitimacy of the CTC is a very strong and legitimate local concern. Another legitimate and highly important concern which we identified is promoting the disaggregation of excessively concentrated ownership; i.e., the reduction of market power.

On the other side of the equation, the opposing parties argue that the effects on interstate commerce will be more than incidental. We acknowledge that our mandatory buy-sell requirement will change in some respects the way the local and regional electricity markets will operate. However, we are not persuaded that the parties protesting this requirement have demonstrated that these changes will cause significant interstate dislocations. Even if this requirement were to cause our regulated utilities to experience some difficulty in marketing their energy, that does not necessarily translate into an impermissible burden on interstate commerce. An otherwise valid regulation will not be invalidated on Commerce Clause grounds simply because it causes some business to shift from one interstate supplier to another. (Exxon Corp. v. Governor of Maryland (1978) 437 U.S. 117, 127.) The courts will examine the burden upon interstate commerce as a whole, not the burden placed on a limited number of California companies.

We disagree with DRA's and Joint Applicants I's arguments that we did not consider alternatives which would have less impact on interstate commerce. The Preferred Policy Decision, pages 51-60, discussed at some length the rationale for the temporary buy-sell requirement. In the course of that discussion, the very alternatives suggested by Joint Applicants I[14] were explicitly or impliedly found to be wanting in terms of solving the problems we identified.

Our resource planning power and our jurisdiction over local franchises allows us considerable discretion to impose conditions on how our regulated utilities market power. It is reasonable to impose conditions which prevent abuse of monopoly power so long as the CTC is being collected. The temporary buy-sell requirement bears a reasonable relationship to the legitimate purpose of protecting California's ratepayers while directing an orderly transition to a competitive environment.

Furthermore, any potential burden of the mandatory buy-sell requirement on interstate commerce is limited. Existing QF and other wholesale power contracts will continue to be honored,

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14. Joint Applicants I propose: 1) allowing continued utility participation in the existing western regional wholesale power market for bulk power and economy energy and surplus power sales, 2) using PBR mechanisms (if standard reasonableness reviews seem too onerous) to gauge the reasonableness of utility power purchases, and 3) using the Power Exchange or another market price index to determine stranded cost calculations. (Joint Applicants I's Application for Rehearing, p. 18; see also DRA's Response, p. 5.)

and the Preferred Policy Decision encourages renegotiation of both types of contracts wherever possible. Only the regulated utilities are subject to the constraint, and only for four years.[15] The total amount of energy affected is thus capped by the current generation capacity of these regulated utilities. Because these utilities will also be divesting generation assets, and because any such asset sold is immediately freed of the obligation to bid into the PX, the amount of energy destined for interstate commerce that is constrained by the buy-sell requirement will only decrease over the 4-year period.

4. The FERC Has Ultimate Jurisdiction Over This Issue.

Finally, the FERC is the ultimate decisionmaker in terms of our preferred market structure, and the FERC has the capability to determine what, if any, undue effects the Commission's proposal is likely to have on interstate commerce. To the extent any party has argued that the regional markets are solely within the FERC's jurisdiction, we respond that we have explicitly acknowledged the FERC's jurisdiction over the ISO and PX, and the terms, conditions and rate structures under which they will operate. We note that the FERC, in its December 18 order, has approved the mandatory buy-sell provision of our proposed restructuring program. In so doing, the FERC stated:

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15. The Preferred Policy Decision established a five-year transition period during which CTC would be collected. However, AB 1890 added new Section 367(a) to the Public Utilities Code, which calls for the majority of the utilities' stranded costs to be recovered within four years (i.e., by December 31, 2001). Consequently, in our Roadmap II Decision, we changed the period during which the mandatory buy-sell requirement would operate from five years to four, to remain consistent with the policy we had established, and to bring that policy into conformance with the specific timeline of AB 1890. (Roadmap II Decision [D.96-12-088], supra, at pp. 8-9 & 42 (Conclusion of Law No. 1) (mimeo).)

> "While the Companies have proposed that they would sell all of their available capacity and purchase the requirements of their retail customers from the PX for the first five years [fn. omitted], the California Commission and Legislature have acknowledged that they cannot mandate the use of the PX for any wholesale sale [fn. omitted]. Rather, both acknowledge that [FERC] has exclusive authority over the rates, terms and conditions of sales for resale of electric energy in interstate commerce by public utilities [fn. omitted], including the Companies and the PX. As a result, the California Commission's order cannot violate the Commerce Clause, nor can its recommendation that [FERC] accept the five-year provision cause any constitutional problem. Very simply, the five-year [mandatory buy-sell] provision can only be implemented if we agree to it. Thus, while this proposal was initiated by the California Commission, [FERC] must act and is acting upon it independently, based on the record before us.
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> . . . .
>
> At issue before [FERC] is whether a PX with a five-year buy-sell requirement for wholesale sales of energy, for only the three California utilities, meets the standards of the FPA. . . . We believe that we can accept the Companies' proposal to make all of their wholesale sales through the PX for five years."

(Order Providing Guidance and Convening A Technical Conference, supra, 77 F.E.R.C. ¶61,265, at pp. 31-33 (mimeo).) The order went on to discuss the considerations outweighing any possible concerns which might arise in the five-year period proposed by the utilities. The FERC found compelling the fact that the PX will create pro-competitive hourly and day-ahead spot markets, with transparent prices set by competitive bidding; the FERC also found it essential to the viability of the PX that the utilities would be participating in the early years. Further, it was important to the FERC that the mandatory aspect of participation in the PX is of limited duration. Finally, the FERC stated that while it could not mandate access to retail markets, it believed such access would only improve competition in the power markets.

The factors which the FERC found important in sustaining the mandatory buy-sell requirement are by and large the same factors which we found compelling.

III. TAKING, MARKET POWER AND RELATED ISSUES

A. Taking Issues

Two types of taking arguments are raised in the rehearing applications: (1) economic taking, and (2) physical taking of property. Edison and PG&E allege that the Preferred Policy Decision concerning the CTC results in economic takings, and PG&E argues that the decision mandates an unlawful permanent physical occupation of its utility system.[16]

1. Economic Taking

Specifically, Edison alleges that the decision results in an unlawful taking, by violating the 5th Amendment of the U.S. Constitution and Article I, Section 19 of the California Constitution, because the decision does not ensure that the utility will have an opportunity to recover all costs resulting from its prudent investments and obligations under the current regulatory regime. (Edison's Application for Rehearing, pp. 2 & 5.)

PG&E makes similar unlawful taking arguments in its rehearing application, by alleging that: (1) the decision

16. In context of their taking arguments, PG&E and Edison are alleging a violation of both the California and the federal constitutions. (See Cal. Const., art. I, §19; U.S. Const., 5th Amend.) Since the law is similar under both constitutions, no distinction is made in this decision.

provides no relief from any confiscation which might occur in the event that PG&B is unable to recover eligible transition costs by the end of 2005; (2) various fossil plant costs (e.g., fixed operating costs and mandated and necessary post-transition incremental capital costs) are not recoverable other than through the PX spot price, except under limited transmission reliability need situations, and thus the decision exposes those costs to market competition, only to largely abandon them in terms of the CTC recovery mechanism adopted; and (3) the reduced return authorized on stranded fossil plant to a level below the cost of equivalent long-term debt violates the Commission's constitutional obligation to set rates which provide the utility with a reasonable opportunity to recover operating costs, return of capital and return on invested capital comparable to similar investments with similar risks. (PG&B's Application for Rehearing, pp. 13-23.)

a) The challenge to the Commission's requirement that transition costs be collected by the year 2005 on the grounds of an unlawful taking is now moot.

In their economic taking claims, PG&B and Edison are essentially asking us to give them an absolute guarantee that they will receive full and complete recovery beyond the year 2005. The law does not require such a guarantee. As the Preferred Policy Decision notes, "we are not required to <u>guarantee</u> full transition cost recovery. We are required only to design a rate structure the total impact of which provides the utilities with the opportunity to earn a fair return on their investment." (Preferred Policy Decision, p. 123 (mimeo), <u>emphasis in original</u>, citing <u>Duquesne Light Co. v. Barasch</u> (1989) 488 U.S. 299.) Our decision to give the utilities the opportunity to recover 100 percent of transition costs, while requiring them to complete collection by the end of 2005, is consistent with the law on taking. (See <u>20th Century Ins. Co. v. Garamendi</u> (1994) 8 Cal.4th 216, 292-293; <u>Federal Power Com. v.</u>

Hope Nat. Gas Co. (1943) 320 U.S. 591, 601-603; Giles Lowery Stockyards v. Dept. of Agriculture (5th Cir. 1977) 565 F.2d 321, 324 & 327.)

However, no further discussion is necessary on this issue because with the enactment of AB 1890, the Commission's requirement that transition costs be collected by the year 2005 has been superseded by the mandates set forth in the newly enacted Public Utilities Code Section 367(a). This section provides that, unless otherwise exempted by subdivisions (a)(1)-(a)(5),[17] "recovery shall not extend beyond December 31, 2001." (Pub. Util. Code, §367, subd. (a).) AB 1890 further provides that transition costs "[b]e adjusted through the period through March 31, 2002, to track accrual and recovery of costs provided for. . . ." (Pub. Util. Code, §367, subd. (d).) Thus, it is AB 1890, and not the Preferred Policy Decision which now controls the time limits for collecting the CTC. Accordingly, we need not address PG&E's and Edison's taking argument concerning our requirement that transition costs be collected by the year 2005.

b) PG&E's allegation that there is no recovery mechanism to avoid a possible confiscation is also moot.

In its rehearing application, PG&E alleges that because there is no recovery mechanism to avoid a possible confiscation of property if a utility does not recover all its transition costs by the year 2005, the Preferred Policy Decision is

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17. These subdivisions provide for different ending dates for recovery for costs associated with employee-related transition costs; buy-out, buy-down, or renegotiation of power purchase contracts; Commission approved contracts to settle Biennial Resource Plan Update issues; nuclear incremental cost incentive plans for the San Onofre nuclear generating station; and exemptions provided in Public Utilities Code Section 374. (Pub. Util. Code, §367, subds. (a)(1)-(a)(5).)

defective on its face. Although we disagree with this allegation, we believe that this issue is no longer before us. With the enactment of AB 1890, the statute rather than our Preferred Policy Decision now controls the time limits for the collection of the CTC. AB 1890 does not provide for a mechanism for recovery beyond the time frame mandated. Accordingly, this Commission is not under a legal obligation to create such a mechanism. To adopt a mechanism would be inconsistent with the statute.

c) PG&E's taking arguments related to fossil generating assets are moot.

PG&E makes several taking arguments concerning fossil generating assets. Specifically, PG&E claims that a confiscation has occurred because various fossil plant costs (e.g., fixed operating costs and mandated and necessary post-transition incremental capital costs) are not recoverable other than through the PX spot price, except under limited transmission reliability need situations, and thus the decision exposes those costs to market competition, only to largely abandon them in terms of the CTC recovery mechanism adopted. PG&E also asserts that the reduced return authorized on stranded fossil plant to a level below the cost of equivalent long-term debt violates the Commission's constitutional obligation to set just and reasonable rates, which provide the utility with a reasonable opportunity to recover return on invested capital comparable to similar investments with similar risks. (PG&E's Application for Rehearing, pp. 15-23.) Although we believe these allegations have no merit, the enactment of AB 1890 has made these issues raised by PG&E moot.

With respect to the issue concerning recovery of various fossil plant costs that are of concern to PG&E, Public Utilities Code Section 367(c) addresses how these costs will be recovered. This statutory provision provides that these transition costs will:

> "[b]e limited in the case of utility-owned fossil generation to the uneconomic portion of the net book value of the fossil capital investment existing as of January 1, 1998, and appropriate costs incurred after December 20, 1995, for capital additions to generating facilities existing as of December 20, 1995, that the [C]ommission determines are reasonable and should be recovered, provided that the additions are necessary to maintain such facilities through December 31, 2001. All 'going forward costs' of fossil plant operation, including operation and maintenance, administrative and general, fuel and fuel transportation costs, shall be recovered solely from independent Power Exchange Revenues or from contracts with the Independent System Operator, . . ." (Pub. Util. Code, §367, subd. (c).)

This statutory provision also provides for some exceptions related to reactive power/voltage support, namely must-run units, and fixed costs paid under fuel and fuel transportation contracts for particular utilities. (Pub. Util. Code, §367, subds. (c)(1) & (c)(2).) Thus, AB 1890 controls recovery of the various fossil plant costs, and thus, this Commission need not address the taking issue raised on these same costs in PG&E's application for rehearing of the Preferred Policy Decision. The issue is moot.

With respect to the reduced rate of return authorized on stranded fossil plant, it has been statutorily incorporated into law. Public Utilities Code Section 367(d) states, in pertinent part: "Recovery of costs prior to December 31, 2201, shall include a return as provided for in Decision 95-12-063, as modified by Decision 96-01-009, together with associated taxes." (Pub. Util. Code, §367, subd. (d).) Consequently, we no longer need to address the taking arguments raised on this issue, as they are now moot with the enactment of AB 1890.

2. Physical Taking

PG&E also claims that there is an unlawful physical taking in violation of the federal and California constitutions, because the decision mandates the physical occupation and control of PG&E's transmission system, implemented through the ISO and for the benefit of third parties which will compete with PG&E for retail sales. (PG&E's Application for Rehearing, pp. 24-28.) PG&E also asserts there is a physical occupation of its distribution systems because the Commission is compelling direct access. (PG&E's Application for Rehearing, p. 24, fn. 41.) In particular, PG&E is arguing that that it "will have lost the ability to control its transmission system for reliability, economy power or retail access purposes, and by reference then, the ability to fully recover the sunk costs of its generation system through sales to those customers." (PG&E's Application for Rehearing, p. 27.)

We disagree that there has been an unlawful physical taking because of our mandates in the Preferred Policy Decision concerning the ISO's operation of the utilities' transmission facilities and the mandating of direct access through the use of the distribution systems as a means for promoting competition. Briefly, our mandates in these areas are merely a legitimate exercise of our police power to regulate these facilities that have been dedicated to public use in order to promote competition and lower consumer rates. (See Pacific Telephone and Telegraph Company v. Eshleman (1913) 166 Cal. 640, 677-678; Dolan v. City of Tigard (1994) 512 U.S. ___, 129 L.Ed.2d 304, 316; Penn Central Transp. Co. v. New York City (1977) 438 U.S. 104, 124.)

More importantly, we need not discuss these claims further, because the ISO and its operations, as well as direct access, are now statutorily mandated by AB 1890, which focuses on ensuring reliability and achieving meaningful competition. (See generally, Pub. Util. Code, §§330, subds.(i), (l)(1), (m), & (r), §§334-340, & §§345-350, concerning the ISO; and Pub. Util. Code, §330, subds. (k)(2)-(k)(3) & (n), §365, subds. (b)(1)-(b)(2), & §366, concerning direct access.) In Public Utilities Code Section 330, the Legislature expressed its intent that

"California's publicly owned electric utilities and investor-owned electric utilities should commit control of their transmission facilities to the Independent System Operator." (Pub. Util. Code, §330, subd. (m); see also, Pub. Util. Code, §334.) Public Utilities Code Section 330 further stresses the importance of direct access in "providing customers and suppliers with open, nondiscriminatory, and comparable access to transmission and distribution services," as a means for achieving meaningful competition. (Pub. Util. Code, §330, subd. (k)(3).) Thus, how the utility's transmission and distribution systems will be used for purposes of electric restructuring is now defined by statute, albeit consistent with the mandates of the Preferred Policy Decision. Accordingly, these physical taking issues set forth in PG&E's Application for Rehearing of the Preferred Policy Decision are made moot by this legislation.

B. Reduction Of Return On Equity To A Level 10 Percent Below The Debt Return.

In the Preferred Policy Decision, we reduced the rate of the return on equity to a level 10 percent below the debt return, because the risks associated with the generation assets will be reduced when the net book value of these assets is accelerated through the recovery of transition costs. We also said that this 10 percent reduction could be recovered by the utility's voluntary divestiture of at least 50% of its fossil generation. (See Preferred Policy Decision, pp. 111 & 123-124 (mimeo).)

In its rehearing application, PG&E is not challenging the Commission's authority to reduce the return on equity. Rather, PG&E argues that there is no record supporting the Commission's decision to reduce the return on equity associated with the recovery of the assets to a level 10 percent below the authorized debt return for fossil fuel units.

Although we disagree that there is legal error, we note that this issue is moot. In the CCR, the parties were asked to

"address the positive and negative aspects of this reduction, and to consider impacts, if any, AB 1890 might have had on this reduced rate of return on equity." (CCR, p. 6.) In the Roadmap II Decision [D.96-12-088], supra, at pp. 31-33 (mimeo), we discussed the comments we received to this question raised in the CCR. Of relevance is Edison's willingness "to accept the return on equity as set forth in the Preferred Policy Decision," and the fact that it was not proposing that the Commission "now reopen this determination.
. . . ." (Id. at p. 32 (mimeo), citing Edison's Comments to the CCR, pp. 11-12.) Further, PG&E and SDG&E asserted that AB 1890 has confirmed the return set forth in the Preferred Policy Decision. (Id.) We agreed. (Id. at p. 33 (mimeo), citing to Pub. Util. Code, §367, subd. (d).) In its Comments, SDG&E also stated that "the Preferred Policy Decision's reduction of return on equity associated with generation facilities [was] appropriate." (Id. at p. 32 (mimeo), citing to SDG&E's comments to the CCR, p. 6.) In light of these comments and our position in Roadmap II Decision, the disposition of this issue raised in PG&E's rehearing application is unnecessary.

C. **Market Power & Voluntary Divestiture**

TURN alleges that the decision's treatment of horizontal market power issues is arbitrary and capricious, because it lacks adequate findings in support and is facially inadequate. (TURN's Application for Rehearing, pp. 13-16.) TURN further argues that no record supports the Commission's belief that a voluntary divestiture scheme is enough to mitigate the unknown and unquantified risks of market concentration.[18]

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18. DRA agrees with TURN that the decision lacks adequate findings of fact and evidence. (DRA's Response, p. 12.)

(TURN's Application for Rehearing, pp. 13-16.) The Coalition of California Utility Employees ("CCUE") also agrees that there are no evidence, findings of fact, or conclusions of law to support the Commission's decision on voluntary divestiture. (CCUE's Application for Rehearing, pp. 8-9.)

Specifically, both TURN and CCUE focus their attention on the Commission's decision regarding voluntary divestiture. They allege that there are no adequate findings and conclusions of law, as well as no record evidence, to support the Commission's determination that 50% divestiture of fossil generating assets will serve to mitigate market power problems. (TURN's Application for Rehearing, pp. 13-15; CCUE's Application for Rehearing, p. 8.) TURN also claims that there is no evidence to support the Commission's proposed incentive for voluntary divestiture, which is an increase in the rate of return for the equity component of up to 10 basis points for each 10% of fossil generating capacity divested. (TURN's Application for Rehearing, pp. 15-16.) CCUE also asserts that there is no record evidence to support any divestiture. (CCUE's Application for Rehearing, p. 8.)

1. There Is A Record To Support Divestiture As A Means To Resolve Market Power Problems.

Contrary to allegations set forth by TURN and CCUE, the record provides support for the Commission decision to prescribe divestiture, as well as voluntary divestiture. California Department of General Services ("DGS") stated that "[u]tilities must be completely divested of all generation assets, in order to have meaningful generation competition, in either a wholesale or retail market." (Comments of DGS on the CPUC's Proposal for Electric Industry and Regulation Restructuring, filed June 8, 1994, p. 9.) The Independent Energy Producers Association ("IEP") indicated that divestiture was a preferred solution to the market power concerns. (IEP's Reply Comments, filed August 23, 1995, pp. 10-11.) The Staff of the Bureau of Economics of the Federal Trade Commission ("FTC") indicated that although there are drawbacks, "[c]omplete divestiture would resolve the competition problem better than regulation of behavior." (Reply Comments of the Staff of the Bureau of Economics of FTC, filed August 23, 1995, p. 9.) John Fielder, Vice President of Regulatory Policy and Affairs for Edison, indicated a willingness to divest if there were unmitigated market power problems. (RT Vol. 32, pp. 4304, 4320, 4368.) SDG&E believed that voluntary divestiture of either generating stations or individual units, is one way to mitigate concerns about market power. (Comments of SDG&E Supporting the CPUC's Proposed Preferred Policy Decision Adopting A Preferred Industry Structure, filed July 24, 1995, pp. 17, A-23 & A-26.) At least one party, the California Energy Commission, suggested a "phased divestiture," which is voluntary. (Comments of the "CEC", filed June 8, 1994, p. III-20, and Comments of CMA, filed June 8, 1994.)

Therefore, TURN and CCUE are wrong that there is no evidence in the record to support divestiture as a means to resolve the market power problems.

2. There Are Findings Of Fact And Conclusions Of Law Concerning The Market Power Problems In The Generation Market And The Need For Divestiture.

In the Preferred Policy Decision, we made adequate findings of fact concerning the market power problems in the generation market, and the need for divestiture. We found that "[d]ivestiture of the utility's competitive generation assets from its regulated assets is the only structural option which will completely eliminate the utility's ability to engage in improper cross-subsidization," and "[c]oncentration of generation ownership in utilities remains a serious unmitigated market power concern." (See Preferred Policy Decision, p. 193 (Finding of Fact No. 35); p. 198 (Findings of Fact No. 66) (mimeo).) There are also conclusions of law which address the market power problems in the generation market. In the Preferred Policy

Decision, we concluded that "a fully competitive market [would not be possible] unless and until . . . any significant lingering ability of the former monopoly utility to distort prices or restrict competition in the new competitive market [was eliminated]." (Preferred Policy Decision, p. 208 (Conclusion of Law No. 34) (mimeo).) We further concluded that "to ensure contestability in the generation market, [the Commission had] to eliminate any undue competitive advantages to existing firms and eliminate barriers to entry of prospective competitors." (Preferred Policy Decision, p. 208 (Conclusion of Law No. 35) (mimeo).)

3. The Issue Concerning the Adequacy of the Proposal for 50% Voluntary Divestiture Is Moot.

In response to the allegations of error set forth by TURN and CCUE concerning the amount of voluntary divestiture, we consider them moot. In the CCR, the parties were asked to provide additional information as to the adequacy of the proposal to have utilities voluntarily divest at least 50 percent of their fossil-fueled generation assets in order to mitigate market power problems. (CCR, p. 5.) Nothing in the comments convinced us to modify our proposal for at least 50 percent voluntary divestiture of fossil generation assets. (Roadmap II Decision [D.96-12-088], supra, at p. 14 (mimeo).) "[W]e are still convinced that this proposal, at a minimum, is adequate for the time being." (Id.) This proposal has also served as a "starting point which has allowed us to move forward with our [ongoing] examination of the market power issues relating to divestiture." (Id.)

Thus, the CCR provided the parties with an opportunity to comment on our proposal for 50 percent voluntary divestiture. Accordingly, another opportunity is unnecessary.

Further, it is noted that Edison recently filed an application for approval to sell 100% of its generating capacity through a Commission-approved auction process. This application does not encompass the Mohave and Four Corners coal units in Nevada and New Mexico, and Edison's Pebbly Beach generation facility, located on Santa Catalina Island. (Edison's Application for Authority to Sell Gas-fired Electrical Generation Facilities, filed November 27, 1996, A.96-11-046, p. 2.)[19] In this application, Edison is proposing to divest well beyond the minimum requirement of 50 percent voluntary divestiture, and the focus of the Commission's examination will be whether this divestiture proposal is sufficient to mitigate market power problems and not on whether the 50 percent is met. Therefore, the controversy over the adequacy of the 50 percent becomes moot.

Further, PG&E has acknowledged that "even after the 50 percent divestiture, . . . additional mitigation will ultimately be necessary." (Order Providing Guidance and Convening a Technical Conference, supra, 77 F.E.R.C. ¶61,265, at p. 6 (mimeo).) "PG&E currently is considering additional generation divestiture." (Id.) Thus, the proposal of 50 percent divestiture is also no longer the controlling factor for mitigating PG&E's market power.

4. The Issue Concerning the Commission's Incentive for Voluntary Divestiture is Moot.

In the Preferred Policy Decision, we provided an incentive for the utilities to voluntarily divest. (Preferred Policy Decision, p. 101 (mimeo).) We concluded that "it [was] reasonable to provide an incentive to the utilities to voluntarily divest their fossil fueled generation assets by granting an increase in the rate of return for the equity component of up to 10 basis points for each 10% of fossil

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19. PG&E filed its Application for Authorization to Sell Certain Generating Plants and Related Assets Pursuant to Public Utilities Code Section 851, A. 96-11-20, on November 15, 1996.

generating capacity divested, provided we have resolved any locational market power concerns associated with the unit and authorize the transfer pursuant to §851." (Preferred Policy Decision, p. 212 (Conclusion of Law No. 66) (mimeo).) In its rehearing application, TURN challenges our adoption of this divestiture incentive for a lack of a record. Although we agree, we believe that this issue by TURN in its rehearing application has been rendered moot by the subsequent consideration of this incentive.

In the CCR, we asked the parties to provide additional information as to the adequacy of the incentive for divestiture. (CCR, p. 5.) We received comments from Edison, PG&E and ORA, and addressed these comments in the Roadmap II Decision [D.96-12-088], supra, at p. 15 (mimeo). These comments provided us with additional information regarding our proposal, but did not persuade us to modify or eliminate this divestiture incentive. (Id.) We further noted that we were "not foreclosing further consideration of the issue, . . . if warranted." (Id.)

Thus, the comments provide us with information and a basis for continuing our divestiture incentive. To grant a limited rehearing to revisit this issue would not be useful, since the parties have already been permitted to address this particular issue as well as to provide information for our consideration.

D. Staffing, Reliability and Voluntary Divestiture

CCUE's application alleges that the Preferred Policy Decision fails to consider certain aspects of the proposed divestiture of generation facilities' effects on reliability. Specifically, CCUE claims that the policy decision is in error because it does not ensure reliability by guaranteeing employment for current utility staff for two years. There are two elements to this claim. CCUE argues both that the decision to require divestiture erroneously did not consider reliability issues and that reliability must be ensured by giving its members a two-year guarantee of employment.

AB 1890, enacting new Public Utilities Code Section 363, now requires that purchasers of divested generating facilities contract with the selling utility "to operate and maintain the facility for at least two years," with certain exceptions. AB 1890 also requires that divested plant remain "available and operational" if necessary to ensure reliability under the standards set by the WSCC and the North American Electric Reliability Council. (Pub. Util. Code, §362.)

We have carefully considered CCUE's application and AB 1890. We conclude that the Preferred Policy Decision is not in error. Most importantly, since the relief CCUE requests has now been substantially enacted as Public Utilities Code sections 362 and 363, the issue is moot. In addition, we believe that reliability issues at this level of detail were not material to the Preferred Policy Decision. (Cf. Pub. Util. Code, §1705.) The Preferred Policy Decision found that benefits would ensure from a new market structure and properly included generation divestiture as part of that restructuring. (Preferred Policy Decision, p. 189 (Findings of Fact Nos. 2 & 3) (mimeo).) At the same time, the Preferred Policy Decision provided for continuing regulatory oversight to prevent market imperfections and to ensure consumer protection. (Preferred Policy Decision, pp. 186-188 (mimeo).) This was a sufficient basis for the conclusion that divestiture should be included in the Commission's preferred electric restructuring policy. The issues raised by CCUE go into the mechanics of electric restructuring at a much greater level of detail and are not material to a decision articulating our policy-level preference for restructuring.

To the extent that CCUE claims that the preferred policy must have included a specific determination on employment matters for generation facility staff in order to escape error, we disagree. Although the Commission has authority over utilities' employment practices, we did not need to exercise that authority in order to articulate our preferred policy. (See General Telephone Co. v. Public Utilities Com. (1983) 34 Cal.3d 817, 827.) When the Preferred Policy Decision was issued, the detailed question of employment practices was not ripe for examination and CCUE's suggestion was not the sole solution to possible problems.

Likewise, to the extent CCUE claims that the goals of our preferred policy should encompass the possibility of potential shortages and high prices, its application does not demonstrate error. If shortages and high prices were to develop we would have had the opportunity to respond to those occurrences when they occurred; we were not required to do so in enumerating the goals of our preferred policy. Also, as CCUE itself points out, our preferred policy required the ISO "to maintain frequency control and comply with all standards" of the Northern American Electric Reliability Council and WSCC. (Preferred Policy Decision, p. 33 (mimeo), emphasis added.) The term "all standards," includes the WSCC's requirement that utilities maintain a capacity "planning reserve." We do not believe further clarification beyond this statement is necessary.

E. Mandatory Buy-Sell Requirement

Joint Applicants I allege that the Commission's justification for requiring that the electric utilities exclusively sell and purchase power through the PX for five years is not supported by the record and is poor public policy. (Joint Applicants' Application for Rehearing, p. 3.)

In the Preferred Policy Decision, we stated that there was "no reason why participation should not be wholly voluntary for all buyers and sellers other than the investor owned utilities jurisdictional to th[e] Commission." (Preferred Policy Decision, p. 51 (mimeo).) Thus, it determined that the investor owned utilities would "be required to bid all of their generation into the Power Exchange and satisfy their need for electric energy on behalf of their full service customers with purchases made from the Exchange," during the five year transition period. (Preferred Policy Decision, p. 51 (mimeo).)

We were motivated by a number of factors to adopt this "temporary" requirement. These factors included "reduc[ing] the scope and burden of the regulatory issues associated with determination of the dimension of the assets which [were] non-competitive in a transparent market, ensur[ing] that those customers who elect to rely upon their distribution utility to procure their electric energy will receive the benefits of those competitive market prices, and provid[ing] a sufficient depth to the Exchange that its market signals may be relied upon as a benchmark for choices to opt for contracts for differences or direct access." (Preferred Policy Decision, pp. 51-52 (mimeo).)

1. Contrary to the Allegations of Joint Applicants I, the Record Supports the Mandatory Buy-Sell Requirement.

In reviewing the record, which included the comments of parties and the transcripts, there is support for the creation of a power pool, for the sake of efficiency. For example, one party noted: "The concept and structure of a wholesale power pool is critical to the efficient operation of a competitive wholesale market." (Comments of the American Wind Energy Association, filed June 8, 1994, p. 8; see also, John Bryson's Comments, RT Vol. 1, p. 55.) Another party, Los Angeles Department of Water and Power ("LADWP") noted that "[t]he use of a wholesale power pool has the potential to transition the State's electric utility industry from its current monopoly structure to a competitive market structure in the least disruptive manner." (LADWP's Response to the CPUC's Proposals for Restructuring the Electric Utility Industry in California, filed July 24, 1995, p. 3.)

Specifically, in terms of the mandatory buy-sell requirement, there is a record to support the Commission's requirement that the utilities "bid all their generation into the Power Exchange, and satisfy their need for electric energy on behalf of their full service customers with purchases made from the Exchange." The mandatory buy-sell requirement appears to have been patterned after the UK model. In explaining the UK model, the Comments of Edison to Order Instituting Rulemaking and Order Instituting Investigation, dated April 20, 1994, filed June 8, 1994, pp. 11-12, stated:

> "[A]ll power suppliers bid prices into the England-Wales pool for each half hour. The pool then determines the market price for that half hour based on the price of the highest winning bid; the pool purchases all the energy needed to meet the region's needs at that price. Distributors and direct access customers in turn must then buy from the pool at this price. In effect, all energy produced in the nation is sold to and bought from the pool at one price."

Edison also noted in these comments: "Without the creation of a region-wide power pool having some of the characteristics of the England-Wales pool, the efficiencies sought by the Commission will have no realistic opportunity to arise. Such a market mechanism is also the key to the Commission's ability to preserve a reliable electric services infrastructure in a direct access world." (Comments of Edison to Order Instituting Rulemaking and Order Instituting Investigation, dated April 20, 1994, filed June 8, 1994, p. 28.) Further, the MOU in particular provides support for the mandatory selling requirement, because it states that "[d]uring the transition period, the parties expect that the IOUs will bid all their generation into the power exchange consistent with PBRs, nuclear settlements and other mechanisms for recovering approved revenues." (MOU, p. 5.) Thus, based on the above, there is record support for the Commission's adoption of the mandatory buy-sell requirement.

2. Joint Applicants I Raise Policy Arguments, Not Legal Arguments, Concerning Mandatory Buy-Sell.

In their rehearing application, Joint Applicants I argue that "barring utility participation in the existing interstate wholesale power market is poor public policy, and threatens ratepayers with significantly higher electric rates."[20] (Joint Applicants I's Application for Rehearing, pp. 5-13.) Joint Applicants I also offer suggestions for addressing the policy concerns that the Commission had in adopting the mandatory buy-sell. (Joint Applicants I's Application for Rehearing, p. 13-19.) The focus of Joint Applicants I's argument here is the impact that the mandatory buy-sell requirement will have on Western Regional Wholesale Power Market.

By these arguments, Joint Applicants I are merely raising public policy arguments, rather than legal arguments. These arguments have been raised before and continue to provide no basis for rehearing. Thus, we will not address them in the context of this order disposing of the rehearing applications.

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20. DRA and Electric Clearinghouse, Inc. agree that the mandatory buy-sell requirement would exacerbate market power problems and would inhibit the development of a healthy and robust market. (See DRA's Response, pp. 6-7; Electric Clearinghouse, Inc.'s Response, pp. 2-3.)

F. Commission Jurisdiction Over Marketers, Brokers and Aggregators.

In the Preferred Policy Decision, we stated that our "consumer protection role may be enhanced if [it] retain[ed] the ability to require energy service providers, including marketers, brokers and aggregators, to register with or obtain a license from this Commission." (Preferred Policy Decision, p. 188 and p. 217, Conclusion of Law No. 110 (mimeo).) Before imposing such a requirement, we indicated that we would consider "whether existing commercial safeguards embodied in the California Department of Consumer Affairs or the Federal Trade Commission [were] sufficient to protect consumers in the restructured electric services industry." We also stated that we would pursue the issue of registration or licensing in its roadmap implementation phase. (Preferred Policy Decision, p. 188 (mimeo).)

In their rehearing application, Joint Applicants II challenge the registration or licensing requirement for two reasons. (Joint Applicants II's Application for Rehearing, pp. 7-11.) First, they claim that the Commission does not have jurisdiction over power marketers, brokers, and aggregators. (Joint Applicants II's Application for Rehearing, pp. 7-10.) Second, Joint Applicants II assert that there is no demonstrable need for any such regulation, and that the record is insufficient to support the conclusion that the Commission's consumer protection role might be enhanced by requiring these entities to either register or obtain a license. (Joint Applicants II's Application for Rehearing, pp. 10-11.)

Although we disagree with Joint Applicants II's allegations, AB 1890 has rendered moot those issues concerning whether we have jurisdiction over marketers, brokers[21] and aggregators, and whether such regulation is necessary. Although marketers, brokers and aggregators are exempted from our jurisdiction as public utilities as defined by Public Utilities Code Section 218 (see Pub. Util. Code, §216, subd. (i)), AB 1890 has given the Commission jurisdiction over these entities as energy service providers for purposes of consumer protection. (See Roadmap II Decision [D.96-12-088], supra, at p. 17 (mimeo).) Further, the Legislature believed that in order to protect the consumer, it was important to require that energy service providers be required to register. (Id. at pp. 17-18 (mimeo), quoting AB 1890, §1(d).) Thus, AB 1890 provides for Commission jurisdiction over these entities, and mandates a registration program. (See generally, Pub. Util. Code, §§331 & 394-396.)

G. Direct Access Limitation.

In the Preferred Policy Decision, the Commission had given the parties an opportunity "to recommend proposals for direct access, including eligibility parameters in the initial phase of direct access, consistent with the principles outlined for direct access and real-time and time-of-use rate options." (Preferred Policy Decision, pp. 65 & 220 (Ordering Paragraph No. 6) (mimeo).) The parties were also asked to carefully consider whether a minimum phase-in schedule was necessary or whether eligibility can be held open to all electricity consumers sooner than five years, or perhaps after the twelve-month initial phase. (Preferred Policy Decision, pp. 69 & 221 (Ordering Paragraph No. 6) (mimeo).)

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21. It is noted that the Commission only has jurisdiction over a broker if it is an aggregator, as defined by Public Utilities Code Section 331(a). (See discussion in Roadmap II Decision [D.96-12-088], supra, at p. 18 (mimeo).)

In the absence of an agreement between the parties for an earlier implementation of direct access, the Commission proposed a minimum five year phase-in program, commencing no later than January 1, 1998. (Preferred Policy Decision, p. 65 (mimeo).) Thus, direct access was required to be completed by January 2003. The Commission also set forth a "default schedule" for phasing in direct access for all three large investor owned utilities: Edison, PG&E and SDG&E. This included an 800 MW participation limit for Edison and PG&E, and 200 MW participation limit for SDG&E. (Preferred Policy Decision, pp. 66 & 220 (Ordering Paragraph No. 6) (mimeo).) The Commission also adopted, as a reasonable eligibility parameter, the MOU's suggestion of an 8 MW threshold limit to be applied to individual customers and aggregated customer groups for the initial phase. (Preferred Policy Decision, p. 68 (mimeo).)

In their rehearing application, Joint Applicants II assert that the evidence does not support the Commission's decision to limit participation in the direct access market during the initial five years of the electric restructuring program. Specifically, these assertions focus on the Commission's schedule for the five year phase-in of direct access, especially the 800 MW limit in the first year, and on the threshold limit of 8 MW set forth in the Preferred Policy Decision. Joint Applicants II also argue that the decision fails to provide findings of fact and conclusions of law on this matter, and thus, the decision fails to comply with Public Utilities Code Section 1705. (Joint Applicants II's Application for Rehearing, pp. 11-14.)[22]

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22. TURN and DRA agreed with these allegations. TURN stated that there was a lack of record evidence, findings of fact or conclusions of law to adequately support the "adopted limitations

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These issues concerning direct access eligibility have been made moot by AB 1890 and subsequent events. In the Roadmap II Decision [D.96-12-088], supra, at pp. 16-17 (mimeo), we described how this legislation has affected the time-frame for the "default schedule," namely that any phase-in must be completed by January 1, 2002. We further noted that "[a]s a result of the shortening of the time, other aspects of the "default schedule," e.g. total number MW available for participation and threshold limitations for eligibility, may [have been] affected." (Id. at p. 17 (mimeo).) In addition, the utilities have recommended faster time schedules in their recent filings. (Id.) Further, although no consensus has been reached on a particular phase-in proposal, the Direct Access Working Group ("DAWG") has offered some alternatives for the Commission's consideration. (DAWG's Report: Design and Implementation of Direct Access Programs, dated August 30, 1996, Section 4.3, pp. 4-20 to 4-28.)[23]

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on participation in the direct access market." (TURN's Response, pp. 15-16.) DRA agreed that the adopted "direct access phase-in schedule [was] overly restrictive and lack[ed] support in the record. (DRA's Response, p. 7.)

23. Our discussion today concerning the phasing-in of direct access does not constitute a final determination as to how we will order implementation of direct access. Issues related to direct access, such as whether a phase-in is necessary, or if there is a phase-in program, how it will be accomplished, will be addressed in a future decision.

Based on the above, we believe that the "default schedule" set forth in the Preferred Policy Decision is no longer appropriate, or even necessary.[24] Accordingly, it is unnecessary to address the issues concerning this schedule raised in Joint Applicants II's rehearing application.

IV. SECTION 1708, CTC AND RELATED ISSUES

A. Section 1708 Was Not Violated Because the Preferred Policy Decision did not Modify Any Existing Commission Orders.

According to PG&E, the Commission's adoption of the Preferred Policy Decision violates Public Utilities Code Sections 1705 and 1708 because the Commission failed to provide parties with an opportunity to be heard, as provided in the case of complaints, and held no evidentiary hearing before it adopted an order which rescinds prior Commission orders and decisions.[25] PG&E asserts that the intent behind its procedural challenge "is to preserve its legal rights primarily with regard to CTC

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24. However, this does not prohibit any party from proposing and supporting, for our consideration, a modified version of the "default schedule" that is consistent with the mandates set forth in AB 1890.

25. Section 1708 states in relevant part:

> "The Commission may at any time, upon notice to the parties, and with opportunity to be heard as provided in the case of complaints, rescind, alter, or amend any order or decision made by it. . . ."

Section 1705 sets out the hearing process for complaints:

> "At the time fixed for any hearing. . . , the complainant and [the other parties], . . . shall be entitled to be heard and to introduce evidence."

treatment. As indicated earlier, it may be that the defects in the record on CTC can be addressed in upcoming CTC implementation proceedings." (PG&E's Application for Rehearing, p. 13 fn. 19.) Regardless of PG&E's strategic reasons for asserting violations of Public Utilities Code Sections 1705 and 1708, those arguments lack legal merit.

PG&E claims a statutory right to evidentiary hearing before the Commission may fundamentally change its existing regulatory structure. However, it has misconstrued the statutes, as Section 1708 only requires the Commission to provide an opportunity to be heard as in the case of complaints (which may require an evidentiary hearing), before the Commission may "rescind, alter, or amend any order or decision made by it".

Public Utilities Code Section 1732 requires an application for a rehearing to set forth specifically the ground or grounds on which the application considers the decision or order to be unlawful. Although PG&E claims that "(t)he policy decision, expressly, as well as impliedly, rescinds, alters and amends numerous Commission decisions," it has not alleged that any particular decision has been amended. PG&E has failed to make the showing required by Section 1732, and on this basis alone, its application for rehearing should be denied.

We further note that the law does not guarantee utility investors the right to an evidentiary hearing before the Commission may consider changes to the regulatory structure.[26]

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26. It is noted that the Commission has the option, if it wishes, to hold evidentiary hearings before it changes an existing regulatory structure. For the Electric Restructuring Proceeding, we have reserved such an option. In the Roadmap Decision [D.96-03-022], supra, at p. 13 (mimeo), we stated: "Each Assigned Commissioner will convene an initial scoping workshop to further define issues to be discussed by these Working Groups and any factual matters which may best be resolved by holding evidentiary hearings."

(Cf. Wood v. Public Utilities Commission (1971) 4 Cal.3d 288; Duquesne Light Co. v. Barasch, supra.) Although utility investors may have premised their investment strategies upon the existing regulatory scheme, like ratepayers, they have no vested interest in the existing ratemaking structure.

This Commission has consistently referred to its restructuring order as a policy decision which announces the Commission's preferred view of the electric industry. The decision orders the utilities to propose industry models for implementing the Commission's policies. The Commission's adoption of implementation models may alter or amend an existing Commission decision. However, the impact of the Preferred Policy Decision upon utility rates, service, or practices is speculative at this point, so it is impossible to identify which, if any, existing orders or decisions may have been modified. For all of these reasons, PG&E's assertion of error lacks merit. Once the means of implementing the Preferred Policy Decision is identified, it will be evaluated to determine if its adoption would alter any Commission decision. If so, the requirements of Section 1708 will be followed.

B. The Adoption of Findings of Fact and Conclusions of Law Based Upon Evidence Received in a Non-Trial Setting Does Not Violate Public Utilities Code Section 1705.

PG&E argues that the requirement of a trial-type hearing mandated by Section 1708 means that findings of fact and conclusions of law based on anything short of a trial-type record cannot support a decision of such magnitude as the Preferred Policy Decision.[27] As noted above, PG&E has failed to establish

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27. Section 1705 states: "[T]he decision shall contain, separately stated, findings of fact and conclusions of law by the commission on all issues material to the order or decision."

the applicability of Section 1708 to this decision.

The real issue is what type of proceeding will provide the requisite notice and opportunity to be heard before the Preferred Policy Decision may be adopted. As explained by the California Supreme Court it is settled that utility ratemaking is a legislative function, and

> "'. . . the prescription of public utility rates by a regulatory commission, as the authorized representative of the legislature, is recognized to be essentially a legislative act. Colorado Interstate Gas Co. v. Federal Power Commission, 324 U.S. 581 (1945). As a ratepayer would have no constitutional right to participate in a legislative procedure setting rates, this right to be heard in a commission proceeding exists at all only as a statutory and not a constitutional right.'"

(Wood v. Public Utilities Commission, supra, 4 Cal.3d at p. 292, quoting Public Utilities Com'n of State of Cal. v. United States (9th Cir.1966) 356 F.2d 236, 241, cert. den. 385 U.S. 816.)

Absent a statutory requirement for an evidentiary hearing, the establishment of procedures by which a showing shall be made to the Commission and the basis of any necessary finding is within the Commission's plenary authority granted by Section 701. The Preferred Policy Decision arose from a rulemaking proceeding[28] that was commenced to reform regulation of the

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28. Article 3.5 of the Commission's Rules of Practice and Procedure states:

> "Rulemaking is a formal Commission proceeding in which written proposals, comments, or exceptions are used instead of evidentiary hearings." (Code of Regs., tit. 20, §14.1.)

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electric services industry in response to customer demand for choice and the presence of competition. Under the rulemaking procedure, the Commission is authorized to rely upon written proposals, comments, or exceptions instead of evidentiary hearings to develop its preferred electric industry structure.

As it did in the proceeding underlying the Wood decision, the Commission has followed its adopted procedure for accomplishing its regulatory task. Section 1705 does not require evidentiary hearings in rulemaking proceedings. No violation of due process has occurred.

Section 1732 requires that at a minimum, PG&E must inform the Commission of the findings and conclusions it believes to be unfounded. "The application for a rehearing shall set forth specifically the ground or grounds on which the application considers the decision or order to be unlawful." Absent specific assertions about the lack of evidentiary record, PG&E apparently concedes that some evidence exists to support each one of the findings and conclusions in the Policy Decision.[29] PG&E has

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> "The Commission may elect to apply rulemaking to . . . (p)roceedings to establish rules, regulations, and guidelines for a class of public utilities or of other regulated entities." (Code of Regs., tit. 20, §14.2.)

29. "(I)f there is evidence to support the (C)ommission's factual findings and conclusions, and those findings and conclusions are the basis for the (C)ommission's order or decision, further review by this court is foreclosed." (Camp Meeker Water System, Inc. v. Public Utilities Com. (1990) 51 Cal.3d 845, 864.)

failed to substantiate its claim that the findings and conclusions of the Policy Decision lack an adequate evidentiary basis.

C. Challenges to the Competition Transition Charge.

In the Preferred Policy Decision, pp. 210-211 (Conclusion of Law No. 57) (mimeo), we adopted the CTC as a nonbypassable charge and imposed it on "all customers who were retail customers on or after December 20, 1995, whether they continue to take bundled electric service from the current utility or pursue other electric service options." Through the CTC, we allowed the utilities to recover their costs associated with contracts for power and prior regulatory commitments, particularly nuclear power costs. As to other generating plants, we provided for an accelerated recovery of the net book value of undepreciated assets and other fixed obligations, combined with a reduction in the return on those assets which make claims for transitional support. (See Preferred Policy Decision, pp. 3-4, 113-116 & 134-135 (mimeo).)

We also determined in the Preferred Policy Decision that transition costs would be allocated to all electric customers using the Equal Percentage of Marginal Cost ("EPMC") allocation methodology. Transition cost recovery was capped so that the price for electricity, on a kWh basis, did not rise above rate levels in effect as of January 1, 1996, without adjustment for inflation. (Preferred Policy Decision, p. 142 (mimeo).)

Although it has confirmed the Preferred Policy Decision's determinations on the CTC in many respects, AB 1890 has modified some of the CTC requirements set forth in the Preferred Policy Decision. For example, the Legislature provided for exemptions to the nonbypassable CTC. (See Pub. Util. Code,

§§369, 372 & 374.)[30] Also, in order to insulate ratepayers from these exemptions, a "fire wall" was created. (Pub. Util. Code, §330, subd. (v); see also, Pub. Util. Code, §367, subd. (e).) Other examples include the following: as discussed previously, the time frame for collecting the CTC set forth in the Preferred Policy Decision has been superceded (see Pub. Util. Code, §367); recovery of CTC is subject to a rate freeze and rate reduction (see Pub. Util. Code, §330, subd. (w) and §368). In disposing of the issues related to the CTC in the rehearing applications, we have considered the impacts of AB 1890 on these matters.

We have carefully reviewed the assertions of error concerning the CTC and conclude that some issues on rehearing have been rendered moot with the enactment of AB 1890. For those issues not rendered moot, no legal error has been shown. Each of the allegations of error is addressed in detail below.

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30. It is noted that AB 1890 permits electrical corporation to apply to this Commission for an order that would exempt a particular class of customer or category of electricity consumption from paying the CTC. Thus, the Commission has authority to grant an exemption; however, such an exemption would be subject to the fire wall specified in Public Utilities Code Section 367(e). (See Pub. Util. Code, §373.)

1. Issues Related to the Notice Required Before the Commission May Impose the CTC on Customers as of December 20, 1995 Are Moot.

The BPUC claims the Commission erred by imposing the CTC on customers without timely notice, which is a matter of concern to customers that conceived and substantially developed bypass projects prior to the date of the Preferred Policy Decision. Although we disagree with the merits of BPUC's claim, we need not address this issue. AB 1890 has codified the Commission's determination that unless otherwise statutorily exempted, the CTC will be imposed on:

> "all existing and future consumers in the service territory in which the utility provided electricity services as of December 20, 1995; provided, that the costs shall not be recoverable for new customer load or incremental load of an existing customer where the load is being met through a direct transaction and the transaction does not otherwise require the use of transmission or distribution facilities owned by the utility . . . ." (Pub. Util. Code, §369.)

Thus, whether any notice was or was not legally required is now a moot question. Since the Legislature has statutorily determined who will pay the CTC, we need not determine this issue.

a) The Exact Magnitude of the CTC or the CTC Collection Mechanism Need Not be Established Prior to the Adoption of the CTC.

BPUC claims that the magnitude of the CTC and the collection mechanism must be revealed to customers prior to attachment of CTC responsibility to enable customers to make informed choices between continued utility service and non-utility alternatives. The lack of that information renders the Commission's notice of CTC liability, provided in the Preferred Policy Decision, invalid, according to BPUC.

With the enactment of AB 1890, this issue also has been rendered moot. However, we note that the Preferred Policy Decision adopted no new rates for electric utilities, and indeed, it capped rates on a per kWh basis, as of January 1, 1996. Since no new rates were adopted in the Preferred Policy Decision, there are no rates about which to notify customers. The Preferred Policy Decision simply adopted the notion that all those who were utility customers on December 20, 1995 are liable for their share of transition costs. EPUC cites no authority for its proposition that customer liability for a charge cannot be established in concept, prior to the adoption of a specific rate.

EPUC's arguments are an attempt to forestall the Commission from applying the CTC to a customer who made a business decision based upon pre-existing rate or service levels. EPUC is not entitled to the relief it seeks.

b) The Issue Related to the Application of the CTC to Customers Who Have Developed or Procured Electricity from Non-Utility Sources Within the Pre-Existing Regulatory Framework Is Moot.

AECA argues that the CTC should apply only to departing customers who exercise new options that become available as a result of restructuring. Application of the CTC to customers who use preexisting options, for which the utilities were already at risk, would be inconsistent with the rationale underlying the CTC and the FERC's interpretation of stranded cost liability, according to AECA. AECA and EPUC request that the following types of customer bypass be exempt from the CTC:

Self-generation,
Cogeneration,
Taking service across the fence, and
Taking service from an irrigation district.

In addition, the parties assert that the following retained utility load should be exempt from the CTC:

> Deliveries pursuant to an agreement with the utility to defer construction of cogeneration facilities in favor of continued utility service, and
>
> Incremental load for which the utility did not incur any stranded costs.

Finally, customers that began development several years earlier, such that their projects will begin operation during the transition period should be exempt from the CTC, according to BPUC.

These issues have been rendered moot by AB 1890. Public Utilities Code Section 372(a) provides exemptions for certain self-cogeneration, cogeneration facilities and emergency generation equipment which fall under specified criteria and meet certain requirements. (Pub. Util. Code, §372, subds. (a)(1)-(a)(3); see also, Pub. Util. Code, §372, subds. (b)-(e).) The Legislature enacted these exemptions "to encourage and support the development of cogeneration as an efficient, environmentally beneficial, competitive energy resource that will enhance the reliability of local generation supply and promote local business growth." (Pub. Util. Code, 373, subd. (a).) Also, Public Utilities Code Section 374 sets forth exemptions for specified loads served by irrigation districts, and loads for Merced Irrigation District and "irrigation districts, water districts, water storage districts, municipal utility districts, and other water agencies which, on December 20, 1995, were members of the Southern San Joaquin Valley Power Authority, or the Eastside Power Authority." (Pub. Util. Code, §374.) Thus, the enactment of these statutory provisions has essentially mooted the issues raised by AECA.

However, we note our disagreement with the allegation that the application of the CTC to customers who use preexisting options would be inconsistent with the rationale underlying the CTC and the FERC's interpretation of stranded cost liability. The FERC decisions cited by the applicants for rehearing are clearly inapposite to the CTC, since the FERC in its <u>Order No. 888</u> has recently affirmed the states' authority to collect the stranded costs of retail generation.

Also, we reject EPUC's assertion that imposing the CTC upon customers whose utility loads are reduced as a result of a change in the use of existing cogeneration facilities or the commencement of operations of new cogeneration facilities would have been prohibited by PURPA. Since AB 1890 has rendered moot the issue of imposing CTC on load served by a self-cogeneration or cogeneration facility, we need not elaborate on this issue.

D. The Commission Properly Imposed the CTC Upon Retail Customers of Utilities Prior to Issuance of FERC's <u>Order No. 888</u>.

EPUC asserts that the CTC should not have been imposed before resolution of the potential jurisdictional conflict between the CPUC and the FERC on the development and application of the CTC. EPUC cites no federal or state law in support of its claim that the Commission's adoption of the CTC is legally contingent upon FERC action. Moreover, the argument is moot, as the FERC has addressed the relationship between federal and state jurisdiction over stranded generation costs in FERC's <u>Order No. 888</u>, <u>supra</u>, at p. 555 (mimeo), which stated:

> "[W]e have made a policy determination that the recovery of retail stranded costs -- an issue over which either this Commission or state commissions could exercise authority by virtue of their jurisdiction over retail transmission in interstate commerce and over local distribution facilities and services, respectively -- is primarily a matter of local or state concern that should be left with state commissions."

The FERC confirmed that the distinction between retail transmission and local distribution facilities will continue to be subject to a case-by-case determination, using the FERC's technical test. Moreover, the FERC committed itself to develop mechanisms to avoid regulatory conflict with states and to provide jurisdictional certainty.[31] Even if none of the facilities are found to be local in nature, the FERC acknowledges that the states have ample authority to collect stranded retail costs from a departing customer.[32]

EPUC has not specified any other jurisdictional issue it believes must be resolved between this Commission and FERC before identification of the customers responsible for CTC may be made. The FERC has concluded that state regulatory agencies have ample authority to provide for collection of stranded electric generation costs, whether through the state's jurisdiction over local distribution facilities or the delivery of energy to end users in general. EPUC's argument lacks merit.

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31. FERC stated: "Therefore, in instances of unbundled retail wheeling that occurs as a result of a state retail access program, the [FERC] will defer to recommendations by state regulatory authorities concerning where to draw the jurisdictional line under the [FERC's] technical test for local distribution facilities, and how to allocate costs for such facilities to be included in rates, provided that such recommendations are consistent with the essential elements of the Final Rule. . . . The [FERC] will consider jurisdictional recommendations by states that take into account other technical factors that the state believes are appropriate in light of historical uses of particular facilities." (Order No. 888, supra, at pp. 437-439 (mimeo).)

32. "Thus, while [the FERC] believe[s] in most cases there will be identifiable local distribution facilities subject to state jurisdiction, [the FERC] also believe[s] that even where there are no identifiable local distribution facilities, states nevertheless have jurisdiction in all circumstances over the service of delivering energy to end users. Under this interpretation of state/federal jurisdiction, customers have no incentive to structure a purchase so as to avoid using identifiable local distribution facilities in order to bypass state jurisdiction and thus avoid being assessed charges for stranded costs and benefits." (Order No. 888, supra, at pp. 436-437 (mimeo).)

R. TURN's Argument Concerning Double Recovery Is Moot.

TURN asserts that the Commission cannot allow recovery of and return on full utility investment through the CTC because authorized rates of return were previously set at levels that compensate the electric utilities for competitive risks; to do so results in a "double recovery" of utility investment. DRA supports TURN's position.

Under traditional cost of service regulation, competitive risks were considered. The Commission first considered competitive risk in setting electric utility return on equity ("ROE") in 1987. It observed that SDG&E might have been experiencing some additional risks stemming from competition in markets which had traditionally been treated as monopolies; it agreed with SDG&E that increased risks associated with fundamental changes in the electric industry in response to competitive pressures would be considered by investors to some extent. (Re Pacific Gas and Electric Company, [D.87-12-068] (1987) 27 Cal.P.U.C.2d 171, 177.) The cost of capital decisions in subsequent years confirmed that the Commission was cognizant of bypass risk when it set utility returns on equity. However, while the Commission "considered" competitive risk, it has never quantified the compensation in the utility's ROE for that risk.[33]

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33. In its 1989 cost of capital proceeding (Re Southern California Edison Company [D.88-12-094] (1988) 30 Cal.P.U.C.2d 506), the Commission found that the risk of competition faced by the electric utilities had not substantially increased during 1988. In the 1991 proceeding (Re Southwest Gas Corporation et al. [D.90-11-057] (1990) 38 Cal.P.U.C.2d 233, 241), the Commission acknowledged, "that the growth in QF produced electric generation has been substantial in the past decade. However, we

(Footnote continues on next page)

In the Electric Restructuring OIR/OII, supra, the Commission promised to account for any incremental utility risk imposed by the direct access proposal contained therein. In the 1995 cost of capital decision, the Commission found that the issuance of the OIR had changed the timing of investor risks due to competition, but not their magnitude, and explicitly increased the ROE to compensate investors for the risk of competition. In the Matter of the Application of Sierra Pacific Power Company Etc. [D.94-11-076] (1994) __ Cal.P.U.C.2d __.) In the 1996 cost of capital decision, the Commission acknowledged its prior year's adjustment and determined that no incremental adjustment to the ROE was necessary to address competitive risk in the electric industry. (Application of Pacific Gas & Electric Company, Etc. [D.95-11-065] (1995) __ Cal.P.U.C.2d __.)

Now that the CTC has been adopted in principle, it will mitigate the loss of revenues due to bypass and eliminate the need to adjust the authorized rate of return in the annual cost of capital decisions. However, no CTC has been collected yet.

(Footnote continued from previous page)

have taken that factor into account in our past cost of capital decisions. . . . We do not believe that a quantitative increase in QF generation from one year to the next necessarily requires an increase in the return on equity."

In the 1993 proceeding, after a consideration of the parties' positions regarding the Biennial Resource Plan Update, pending state and federal regulatory review of transmission access, utility purchased power risk, and risks under incentive ratemaking, the Commission stated: "We do not believe that the electric industry restructuring risks have increased since the last two cost of capital proceedings." (Re Pacific Gas and Electric Co. [D.92-11-047] (1992) 46 Cal.P.U.C.2d 319, 364-366.)

At this time, there has been no duplicative compensation for competitive risk as feared by TURN. The electric utilities should bear the burden of demonstrating the reasonableness of continuing the ROE increment for competitive risk, if they seek continuation of that risk adjustment in their annual cost of capital filing (or successor proceeding).[34] We envision that exclusion of competitive risk from cost of capital proceedings will prospectively avoid the double recovery feared by TURN.

However, we note that the risk of "double recovery" for past periods exists because the generation bypassed during 1988-1994 may very well be the same generation found to be uncompetitive in the restructured electric market. The perceived risk of electric utility bypass was considered by the Commission in setting the ROE during 1988-1994, so the CTC should not now compensate a utility for displacement of its generation by competition in effect before the date of the Preferred Policy Decision.

However, although we would tend to agree with TURN concerning this "double recovery" for past periods, AB 1890 makes this issue moot. The law provides: "Recovery of costs prior to December 31, 2001, shall include a return as provided for in Decision 95-12-063, as modified by Decision 96-01-009, together with associated taxes." (Pub. Util. Code, §367, subd. (d).) Accordingly, no adjustment is now possible. But as noted above, the issue of double recovery will be addressed in future

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34. Further, we note that such an adjustment is not legally required, because the law does not protect the utility from the economic forces of competition. (See Public Serv. Com. of Montana v. Great Northern Util. Co. (1933) 289 U.S. 130, 135; Market Street R. Co. v. Railroad Com. of Cal. (1945) 324 U.S. 548, 567; Peerless Stages, Inc. v. Santa Cruz Met. Transit Dist. (1977) 67 Cal.App.3d 343, 347.)

proceedings related to prospective risks and rewards for the utility.

F. TURN'S Argument for Evidentiary Hearings on the Impact of Transition Cost Recovery on Utility Financial Integrity Lacks Merit.

TURN also asserts that without evidentiary hearings to determine what constitutes "adequate transition cost recovery" and the requisite degree of "financial integrity" for the utilities, Finding of Fact No. 50[35] is practically meaningless, and the resultant violation of Section 1705 warrants rehearing of the Preferred Policy Decision. By this argument, TURN basically is arguing that the utilities are not entitled to recover costs that the Commission previously determined to be reasonable because there has been no showing that the recovery of those costs is needed to sustain utility financial integrity. This argument lacks merit, because the reasonableness of these costs has been established in prior Commission decisions and cannot now be challenged in the context of the Electric Restructuring OIR/OII. In the Preferred Policy Decision, we are merely allowing for accelerated recovery of these costs, i.e. to the extent that these costs are uneconomic in a competitive generation framework. We are not granting additional cost recovery with respect to these costs. Thus, we are giving the utilities a fair opportunity to recover costs previously found reasonable. Accordingly, no independent showing of the reasonableness of these costs need be made; thus no evidentiary hearings are needed.

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35. Finding of Fact No. 50 states: "If we do not provide for adequate transition cost recovery, the move to competition may threaten the utilities' financial stability." (Preferred Policy Decision, p. 196 (mimeo).)

TURN further objects to the Commission's declarations that investor uncertainty about the recovery of transition costs may harm the utility's ability to raise capital, may result in a higher cost of debt, and may threaten the utilities' financial stability. (Preferred Policy Decision, p. 119 (mimeo).) Those statements set forth basic economic principles that are of common knowledge. Thus, evidentiary hearings are not needed to consider these statements. In addition, the Commission's concern regarding financial integrity is consistent with AB 1890, which provides "investors in these electrical corporations with a fair opportunity to fully recover the costs" associated with the transition to a competitive generation market. (See Pub. Util. Code, §330, subd. (t); see also, Pub. Util. Code, §330, subd. (d).)

G. The Issue Concerning the Allocation of Transition Costs on the Basis of EPMC Methodology Is Moot.

AECA states "it is not at all clear that it would be proper to use marginal cost ratemaking concepts to allocate (transition costs, since they are) historical costs." It suggests that if marginal cost ratemaking is used to allocate transition costs, the current EPMC targets should not be used, as they are too "broad based" to be used to allocate stranded generation, QF contracts, and regulatory assets. AECA asks the Commission to investigate whether marginal cost ratemaking is applicable to transition cost allocation, and if so, to commence a separate proceeding to determine appropriate EPMC targets for this purpose.

We need not address this issue raised by AECA. The determination that the EPMC methodology will be used as the basis for allocation of transition costs is no longer controlling. AB 1890 now defines the law for allocating transition costs. (See Pub. Util. Code, §367, subds. (e)(1)-(e)(3).) Although the Commission retains "existing cost allocation authority," it is subject to the mandates of the fire wall and the rate freeze. (Pub. Util. Code, §367, subd. (e)(3).) Since AB 1890 now controls the allocation of transition costs, the issue raised by AECA is moot.

V. CALIFORNIA ENVIRONMENTAL QUALITY ACT

We now turn to the applications' claims that our articulation of a preferred electric restructuring policy did not meet CEQA's procedural requirements for the timing of agency action. The Preferred Policy Decision concluded that CEQA review of electric restructuring should commence because the articulation of the preferred policy represented the point at which meaningful review could begin. (Preferred Policy Decision, pp. 177-178 (mimeo).) Although we "acknowledged the applicability of CEQA" throughout this proceeding, prior to the articulation of our preferred policy we were unable to make CEQA determinations because we had not yet reached "the stage [at which] a project could be assessed."[36] Once we reached that stage we embarked upon an environmental review that would comply with CEQA's requirements--even though we were not persuaded that such a review was strictly necessary. (Preferred Policy Decision, pp. 5, 177-178 (mimeo).) We pointed out that none of the "policy proposals" presented in our Preferred Policy Decision should be considered final until environmental review was complete. Conclusion of Law 108 stated: "Because we are

36. Following the filing of a motion by NRDC, we reviewed CEQA issues in each of our orders on electric restructuring. (See Interim Opinion: Procedural Schedule, Call for Briefs, and Applicability of CEQA ("Interim Opinion") [D.94-12-027, p. 21 (mimeo)] (1994) __Cal.P.U.C.2d__; Proposal II, dated May 24, 1995, pp. 77-78, in Order Designating Proposed Policy [D.95-05-045] (1995) __Cal.P.U.C.2d__.) On none of those occasions did we find a sufficiently stable proposal to allow us to determine even the threshold issue of whether the electric restructuring constituted a "project" under CEQA.

embarking on the environmental review process, none of the policy proposals contained in this decision are final. Today's decision constitutes the Commission's identification of preferred policy and the project proposal, which cannot be finally adopted or approved until after we have prepared the EIR and considered its findings." (Preferred Policy Decision, p. 217 (mimeo).)

In their applications for rehearing, TURN and CCUE state CEQA's requirement that environmental review occur before an agency makes a "final decision." (See, e.g., TURN's Application for Rehearing, pp. 17-18.) Both parties claim error by alleging, despite Conclusion of Law No. 108, that the Preferred Policy Decision constitutes more than our articulation of an electric restructuring policy proposal. (See, e.g., CCUE's Application for Rehearing, pp. 12-14.)

During the pendency of the applications for rehearing, the Legislature passed Assembly Bill (AB) 1890, which was signed into law by the Governor on September 23, 1996. (Stats. 1996, ch. 854.) This new law determines that California's electric utility industry should be restructured, and establishes basic ground rules for a new, more competitive, market structure. (Stats. 1996, ch. 854, § 1(b), (c), (d), (e), pp. 3-4.) On September 30, 1996, Commissioner Fessler issued the CCR addressing AB 1890 and stating the anticipated final electric restructuring decision was no longer "a discretionary responsibility of the Commission." Following receipt of comments on this issue, we determined to stop preparing the EIR studying the preferred policy in D.96-12-075, referred to as the "AB 1890 CEQA Decision." (<u>AB 1890/CEQA Decision</u> [D.96-12-075], <u>supra</u>.) There, we concluded that since we were "no longer to decide whether or not to move from traditional regulation to a more competitive scheme, nor what the broad outlines of the competitive market should be, then there is no reason for us to study the environmental consequences of making such a decision." <u>Id</u>. at p. 7 (mimeo).)

We have carefully reviewed the Preferred Policy Decision in light of the claims made in the applications for rehearing, AB 1890 and the AB 1890/CEQA Decision. We conclude that the applications for rehearing do not indicate error in the Preferred Policy Decision for several reasons. Most importantly, the claims raised in the applications for rehearing are now moot. Legislation codifying the fundamental decision to move to more competition and outlining the structure for a new market makes an EIR studying the preferred policy unnecessary. Thus, questions about when an EIR should have been prepared are only academic at this point. Moreover, even if the applications raised issues that were not hypothetical, we would conclude that they did not demonstrate error. We properly exercised our discretion by commencing environmental review as soon as meaningful review could occur, which was with the articulation of a proposal in the Preferred Policy Decision. Since we did not adopt a proposal in the Preferred Policy Decision, the commencement of environmental review at that point was proper. We also note that the Preferred Policy Decision did not authorize any irreversible action to be taken until the EIR was complete, and point out that the mere potential for future error in subsequent decisions does not indicate error in the Preferred Policy Decision.

A. Since an EIR Studying the Preferred Policy is no Longer Required, Allegations of Error Based on the Timing of Such an EIR are Moot.

As we explained in detail in the AB 1890/CEQA Decision, AB 1890 resolves the fundamental question of whether California should move from traditional cost-of-service electric utility regulation to a new regulatory scheme. AB 1890 requires the move to a more competition-focused regulatory scheme and outlines a new, more competitive, market structure. (See AB 1890/CEQA Decision [D.96-12-075], supra, pp. 12-14 (mimeo.) Thus the new law effectively makes the fundamental decisions on electric restructuring that we anticipated making once we had prepared and considered an EIR studying the preferred policy. (Cf. Preferred Policy Decision, p. 217 (Conclusion of Law 108) (mimeo); AB 1890/ CEQA Decision [D.96-12-075], supra, p. 3 (mimeo).)

With respect to CEQA, the applications focus on the requirement that environmental review be conducted before a decision to move forward is made. TURN and CCUE claim that our proposal for meeting CEQA's requirements and our timing for preparing the EIR would have been in error. Applicants argue that an electric restructuring EIR prepared following the articulation of the preferred policy would fail to meet CEQA's requirements. In support of this argument, the applications argue that the Preferred Policy Decision does not clearly establish that final adoption will occur only after the EIR is prepared.

We believe these claims do not demonstrate error since we are not now required to make a policy-level decision, and thus not required to conduct the policy-level environmental review in advance of such a decision. We no longer have responsibility for resolving fundamental policy-level issues because AB 1890 settles those questions. And since the requirement that we perform policy-level environmental review stems from our responsibility to resolve those fundamental issues, that responsibility is also effectively removed by AB 1890: if we no longer have responsibility to decide policy-level restructuring questions, and to include environmental factors in our decision, questions about the proper time and strategy for conducting environmental review are merely academic.

Thus the CEQA issues raised in the applications no longer have the potential to demonstrate error in the Preferred Policy Decision. Put most bluntly, the CEQA questions raised in the applications for rehearing are hypothetical. Policy-level CEQA issues have now been disposed of entirely as a result of AB 1890, while specific implementation CEQA issues remain to be dealt with as they arise, in the same manner we anticipated in the Preferred Policy Decision. (See Preferred Policy Decision, p.180 (mimeo); Roadmap II Decision (D.96-12-088), supra, at pp. 39-40 (mimeo).) As a result, the relief requested in the applications is no longer possible to grant. Since we are no longer able to make policy level decisions about electric restructuring we cannot prepare and consider an EIR before such decisions are made.

B. Nevertheless, the Preferred Policy Decision Achieved the Proper Balance Between Meaningful and Early CEQA Review.

Even if the applications for rehearing raised issues that were still pertinent, those claims would not show error. As we explain below, the Preferred Policy Decision adopted a proper approach to the CEQA compliance questions then presented. We believe the Preferred Policy Decision property balanced early and late review and commenced the EIR at the proper time. The Guidelines[37] recognize that a decision to perform environmental review must occur at a point in the development of a project that makes sense. Guidelines section 15004(b) states:

> Choosing the precise time for CEQA compliance involves a balancing of competing factors. EIRs and Negative Declarations should be prepared as early as feasible in the planning process to enable environmental considerations to influence project program and design and yet late enough to provide meaningful information for environmental assessment.

The California Supreme Court has noted that an environmental study prepared before reliable information was available would "tend toward uninformative generalities" while

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37. Regulations interpreting the California Environmental Quality Act are referred to here as the "Guidelines." They appear at Cal. Code of Regs., tit 14, §§ 15000-15387.

one delayed until after key decisions were made "could not assure that such decisions reflected environmental consideration." (No Oil, Inc. v. City of Los Angeles (1974) 13 Cal.3d 68, 77, fn. 5.) The Court quoted from Scientists' Inst. for Pub. Info., Inc. v. Atomic Energy Com. (1973) 481 F.2d 1079, 1094: "Thus we are pulled in two different directions. Statements must be written late enough in the development process to contain meaningful information, but they must be written early enough so that whatever information is contained can practically serve as an input into the decision making process."

The initial responsibility for balancing these two factors rests with the agency whose task is to include environmental information in its decisionmaking process. In Mount Sutro Defense Committee v. Regents of the University of California ("Mount Sutro") (1978) 77 Cal.App.3d 20, 33, the Court of Appeal found that "[n]owhere in CEQA and its implementing Guidelines is a precise time specified at which an EIR must be prepared during the project planning process." The court stated that "the question of timing of the preparation of an EIR is basically an administrative decision." (Id. at p. 36.) That decision is to be made "initially by the agency itself, which decision is to be respected in the absence of manifest abuse." (Id. at, p. 40, citing Pub. Resources Code, §21168.5; See No Oil, Inc. v. City of Los Angeles, supra, 13 Cal.3d at p. 88.)

In this proceeding, we properly balanced the factors of meaningful review and early review. The conceptual nature of the electric restructuring made it difficult to strike this balance since environmental review involves study of actual physical changes. Yet, for the most part, the electric restructuring was not designed to make any physical changes; it was a plan to reform economic relationships. Moreover, no actual changes would have ensued until electric restructuring policy was put into place. What the EIR would have studied were the physical changes that may have resulted from proposed future reform of economic relations. Such a study could not have begun until there was an actual proposed electric restructuring proposal on which to perform environmental review. When these factors are considered, the proper time to begin preparing an EIR was after the issuance of the Preferred Policy Decision. The Preferred Policy Decision set out for the first time a complete and detailed electric restructuring policy that we proposed to undertake once we completed necessary conditions precedent. Before we issued our Preferred Policy Decision, the lack of a fixed, complete and detailed electric restructuring proposal would have prevented us from performing a meaningful study had we attempted to prepare an EIR. Since the Preferred Policy Decision was not intended to be our final decision on electric restructuring, our EIR was planned to be early enough to allow consideration of environmental information before any final determinations were made.

We emphasize that the Preferred Policy Decision represented an initial articulation of an electric restructuring proposal; it did not adopt one. The applications for rehearing claim that the articulation of our preferred electric restructuring policy effected an erroneous adoption of that policy. We disagree. The Preferred Policy Decision concluded that no approval of, nor any action to implement, our proposal would be taken before we completed CEQA review. Conclusion of Law No. 108 states: "Because we are embarking on the environmental review process, none of the policy proposals in this decision are final. Today's decision constitutes the Commission's identification of preferred policy and the policy proposal. . . ."

In addition, our decision to start (but not complete) work on a number of issues that faced us as conditions precedent to final adoption or approval is not the same as actually implementing the preferred policy. Our goal was to ensure that if the proposed policy was finally adopted, "components" would have been "in place" at the beginning of the anticipated transition period. (Preferred Policy Decision, p. 18.) This strategy would not have foreclosed options or prevented us from adopting alternatives, mitigation or "no project" at our final decision point. An agency is not prohibited from taking preliminary steps to design and advance its proposal before final approval so long as that agency takes no irrevocable steps to adopt or implement its proposal. CEQA only requires agencies to consider environmental factors and not to adopt a final policy pre-EIR. Allegations that error might have occurred in the future as we undertook preliminary matters do not indicate error in the Preferred Policy Decision. If, before the EIR was complete, we took an action that did not meet CEQA's requirements, it would be that action that was in error, not the Preferred Policy Decision.

Laurel Heights Improvement Assn. v. Regents of University of California ("Laurel Heights") (1988) 47 Cal.3d 376, 394 cited in the applications for rehearing, points out that an EIR must be used to inform decisionmakers of the environmental effects of a proposed action before that action is adopted. The Preferred Policy Decision complied with Laurel Heights since our EIR was designed to be informative by studying the preferred policy in order to ensure meaningful environmental review. There was no inconsistency between the determination to conduct environmental review before "finally . . . adopt[ing] or approv[ing]" an electric restructuring policy and the fact that the Preferred Policy Decision spelled out our policy preference for electric restructuring.

It appears that a good part of the applications' concern stems from applicants' interpretation of the language of our Preferred Policy Decision. For example, CCUE claims that because D.95-12-063, as modified by D.96-12-009, refers to itself as a "policy decision," Conclusion of Law No. 108 is "futile" and an "attempt to avoid acknowledging that a decision has been made." (CCUE's Application for Rehearing, p. 13.) In this connection, we wish to emphasize that none of the discussion portion of the Preferred Policy Decision should be read as an adoption of a restructuring policy since the Preferred Policy

Decision represents a proposal. D.95-12-063, as modified by D.96-12-009 is nominally a "decision" because of our historical practices and because we prefer to use English words instead of streams of numbers such as "D.95-12-063, as modified by D.96-01-009." Moreover, we were not required by Laurel Heights to remain indifferent to our policy until the EIR was completed. Since we were the authors and proponents of our plan, we obviously chose to state our proposal in terms of what we intended to accomplish, and to explain our proposal's benefits. We did not propose the electric restructuring policy in the Preferred Policy Decision because we were indifferent to it. Rather, our preferred policy is what we proposed to accomplish, conditional on environmental review and satisfaction of other conditions precedent. Articulating a policy preference as a starting point for environmental review and other further study should not be confused with adopting a policy. In the event of any inconsistency with the discussion text, Conclusion of Law No. 108 must be seen as controlling. We will modify the Preferred Policy Decision to this effect.

Finally, we note that the applications for rehearing do not specify which elements of the Preferred Policy Decision they believe do not meet CEQA's requirements or are at odds with Conclusion of Law No. 108. It is also difficult to tell which future actions have the potential to be in error. (See TURN's Application for Rehearing, p. 18.) D.95-12-063, as modified by D.96-01-009 is 229 pages long. We should not be forced to guess at what parts of our decision may be in error, or decide on an application for rehearing without first having the opportunity to review and correct the alleged error. For this reason we have adopted Rule 86.1 of our Rules of Practice and Procedure. The applications' vagueness in this matter does not allow us full opportunity to review and modify the Preferred Policy Decision. We believe this alone would constitute sufficient grounds to deny the applications for rehearing. For this and the above stated reasons we conclude that the Preferred Policy Decision was not in error with respect to CEQA.

THEREFORE, IT IS ORDERED that the Preferred Policy Decision will be modified as follows:

1. The last sentence in the full paragraph on page 32 should be modified to read:

> "We strongly urge that the filing incorporate the principles delineated below, which we believe are critical to the successful operation of the ISO."

2. The first two sentences in the second full paragraph on page 48 (under 1.) should be modified to read:

> "We authorize PG&E, SCE and SDG&E to work together and with California's municipal and publicly owned utilities and other parties to propose recommendations for the establishment and operation of the Power Exchange. We strongly urge that these recommendations follow the policy guidance we describe below and include proposals for ownership, structure, pricing mechanisms, bidding protocols, and communications with the ISO."

3. Ordering Paragraph No. 1 is modified to read:

> "Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), and San Diego Gas & Electric Company (SDG&E) are authorized to work together and with other parties to develop a detailed proposal for submission to the Federal Energy Regulatory Commission (FERC) to establish the independent system operator (ISO) and its protocols and transfer operational control of the utilities' transmission facilities to the ISO. We authorize and encourage these parties to file this proposal at FERC and simultaneously file and serve it in this docket within 130 days after the effective date of this decision. We urge that this proposal comply with the principles and guidelines for operational issues outlined in Chapter III of this decision and include

recommendations for ownership, financing, and corporate structure of the ISO."

4. Ordering Paragraph No. 3 is modified to read:

"PG&E, SCE, and SDG&E are authorized to work together and with other interested parties to prepare a joint proposal to establish the Power Exchange. We urge that this proposal follow the policy guidance described in Chapter III and include recommendations which address the ownership, financing, corporate structure, pricing mechanisms, and bidding protocols of the Power Exchange. In addition, we urge that this proposal address communications with the ISO and additional Power Exchange responsibilities, as discussed in chapter III. PG&E, SCE, and SDG&E are urged to include recommendations for the ownership, organizational structure, and working capital of the Power Exchange in their proposal. We authorize and encourage the parties to file this proposal at FERC and simultaneously file and serve it in this docket no later than 130 days after the effective date of this decision. If parties are unable to agree on a joint proposal, PG&E, SCE, and SDG&E are urged to file and serve individual proposals in this docket; these proposals shall address the issues outlined above and be filed and served no later than 130 days after the effective date of this decision."

5. The following sentence shall be deleted from page 10, lines 14-15 of Appendix B: "The MOU was made available to other parties on September 11, 1995 and filed on September 18, 1995." The following sentence should replace this deleted one: "Copies of the MOU were mailed to all parties and submitted to the Commission by September 11, 1996."

6. The phrase "recognize that both and utilities" on line 5, page 131, should be replaced by the phrase "recognize that both QFs and utilities".

7. Conclusion of Law 108, on page 217, is modified to add a new final sentence reading, "In the event of any

inconsistency with the discussion portion of this decision, this Conclusion of Law must be read as controlling."

IT IS FURTHER ORDERED that:

8. Rehearing of D.95-12-063, as modified by D.96-01-009, and as modified herein, is denied.

This order is effective today.

Dated February 5, 1997, at San Francisco, California.

P. GREGORY CONLON
President
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
RICHARD A. BILAS
Commissioners