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Decision 95-12-007 December 6, 1995

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Rulemaking to Consider the Commission's Compliance with the Energy Policy Act of 1992.	))))	R.93-06-001 (Filed June 2, 1993)

ORIGINAL

(See Decision 93-11-068 for appearances.)

I N D E X

OPINION ON ISSUES ARISING UNDER THE NATIONAL ENERGY POLICY ACT

The National Energy Policy Act of 1992 (EPAct) requires state public utility commissions to consider various standards which are added to the Public Utility Regulatory Policies Act of 1978 (PURPA) and the Public Utility Holding Company Act of 1935 (PUHCA). Today's decision addresses standards related to integrated resource planning and energy efficiency for electric and gas utilities (Sections 111 and 115), exempt wholesale generators (EWGs) and affiliated transactions (Section 711), investment in foreign utilities (Section 715), and various other standards, as described below. Decision (D.) 93-11-068, 52 CPUC 2d 167 issued November 23, 1993, addressed wholesale power purchase standards (Section 712).[1]

1. Background

EPAct is a comprehensive energy law which directs State commissions with ratemaking authority over gas and electric utilities to determine the desirability of adopting certain "standards," after receiving input through a public process.

We instituted Rulemaking (R.) 93-06-001 as our vehicle for EPAct compliance. Many of the same or similar issues have arisen in our current proceedings, including

1. The standards addressed in D.93-11-068 included implications of high debt leverage used by EWGs, regulatory preapproval of wholesale power purchase agreements, and determination of adequacy of the EWG's fuel supply. D.93-12-022, 52 CPUC 2d 390, addressed the Section 712 standard concerned with the impact of purchased power on utility cost of capital.

R.94-04-031/Investigation (I.) 94-04-032) our comprehensive rethinking of traditional regulatory structure for California's electric services industry. As we stated in D.93-11-068, our findings in this proceeding are made within the current regulatory framework. (52 CPUC 2d at 168.) We may decide in another forum to modify that framework in fundamental ways, which in turn may cause us to revisit some of these findings to ensure compatibility with the modified framework. If we find that certain EPAct standards should be incorporated within the revised regulatory structure, we will implement that finding in a broader generic proceeding to be designated or on a utility-by-utility basis.

We address today the standards that state commissions must consider, pursuant to Sections 111, 115, 711, 715, and Title IX of EPAct. The following parties commented on these standards: Pacific Gas and Electric Company (PG&E); PacifiCorp; San Diego Gas & Electric Company (SDG&E); Sierra Pacific Power Company (Sierra); Southern California Edison Company (Edison); the Commission's Division of Ratepayer Advocates (DRA); Toward Utility Rate Normalization (TURN); California Manufacturers Association (CMA); U.S. Department of Defense (DOD); and Allied Signal.

As we stated in our earlier decision, utilities in both the electric and gas industries are increasingly facing the challenges of competition, which we believe will benefit consumers in the long run by promoting innovation, increased efficiency, lower rates, and better services. We therefore emphasize that this is the time when regulatory standards restricting the development of a competitive market should be lightened or removed, so long as safety and reliability are not sacrificed and captive ratepayers are protected from unfair competitive practices. We turn next to a discussion of the individual standards, and discuss each standard with this framework in mind.

2. Section 111 and Section 115: Encouraging Integrated Resource Planning and Energy Efficiency

Section 111(a) of EPAct adds three paragraphs to Section 111(d) of PURPA:

"(7) Integrated Resource Planning. Each electric utility shall employ integrated resource planning. All plans or filings before a State regulatory authority to meet the requirements of this paragraph must be updated on a regular basis, must provide the opportunity for public participation and comment, and contain a requirement that the plan be implemented.

"(8) Investments in Conservation and Demand Management. The rates allowed to be charged by a State regulated electric utility shall be such that the utility's investment in and expenditures for energy conservation, energy efficiency resources, and other demand side management measures are at least as profitable, giving appropriate consideration to income lost from reduced sales due to investments in and expenditures for conservation and efficiency, as its investments in and expenditures for the construction of new generation, transmission and distribution equipment. Such energy conservation, energy efficiency resources and other demand side management measures shall be appropriately monitored and evaluated.

"(9) Energy Efficiency Investments in Power Generation and Supply. The rates charged by any electric utility shall be such that the utility is encouraged to make investments in and expenditures for, all cost-effective improvements in the energy efficiency of power generation, transmission and distribution. In considering regulatory changes to achieve the objectives of this paragraph, State regulatory authorities and nonregulated electric utilities shall consider the disincentives caused by existing ratemaking policies and practices, and consider incentives that would encourage better maintenance and investments in more efficient power generation, transmission and distribution equipment."

Section 115 adds similar standards to Section 303(b) of PURPA relating to integrated resource planning and investments in conservation and demand-side management (DSM) to encourage investments in conservation and energy efficiency by gas utilities. Both Section 111 and Section 115 require that if a state regulatory authority determines to implement these standards, it shall protect small businesses engaged in DSM measures. The state authority must therefore consider the impact on such small businesses and ensure that utility actions will not provide utilities with unfair competitive advantages over such small businesses.

In soliciting comments on these issues, we stated that we believe this Commission has already considered the three standards for the major California electric utilities and the two standards for the major gas utilities in existing or past proceedings. PURPA contains a "grandfathering" provision for these standards, which may be applicable here. Congress recognized that several states have implemented the standards encouraged under these sections and will allow "grandfathering" if states demonstrate that they have implemented the standards by referencing actions they have already taken.

Overall, the parties generally agree that the Commission either has already considered and implemented standards compatible with those proposed by EPAct or is considering such standards in pending proceedings, and that no additional steps are required to implement either Section 111(a) or Section 115.

2.1 Integrated Resource Planning

The integrated resource planning (IRP) standards of Section 111 and Section 115 have been thoroughly addressed in the Biennial Resource Planning Update proceeding (Update) (I.89-07-004) for our electric utilities, the long-run marginal cost (LRMC) proceeding (I.86-06-005) for our gas utilities, and in the DSM proceeding (R.91-08-003/I.91-08-002). Parties generally believe

that these proceedings are sufficient to implement the mandates of EPAct.[2] DRA does not believe that additional consideration is necessary for the smaller utilities which we regulate. Pacificorp and Sierra Pacific agree. For those utilities, IRP and DSM issues are considered as part of their general rate cases.

Electric Utilities

Our resource planning process has been evolving since 1982 and, for electric utilities, culminated in the Update, which uses the Biennial Electricity Report prepared by the California Energy Commission as its starting point. The Update has been the Commission's vehicle for ensuring compliance with the resource goals and directives codified in Public Utilities (PU) Code §§ 701.1 and 701.3, and has been one of the ways by which the Commission has implemented PURPA.

Our goals for resource procurement, articulated in several Commission decisions and mandated by statute, are the provision of reliable, least-cost, environmentally sensitive, and safe electricity service. Resource procurement in California, then, has implemented federal and state policy to reduce dependence on fossil fuels and reduce dependence on large base-loaded utility plant, as well as improving the efficiency of generating plants.[3]

In April 1994, we issued our restructuring rulemaking and investigation (R.94-04-031/I.94-04-032), a sweeping proposal for

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2 Edison believes that while the Commission has given extensive consideration to IRP, the Commission has not completely implemented this standard. We do not address Edison's comments here as they are outside the scope of this proceeding. Similarly, CMA proposes that the Commission will not adequately address IRP until it seriously considers retail wheeling. These issues are addressed in R.94-04-032/I.94-04-031.

3 See, for example, D.94-06-050; D.92-04-045, 44 CPUC 2d 6; D.91-06-022, 4 CPUC 2d 512; and D.90-03-060, 36 CPUC 2d 2.

the broad restructuring of the electric services industry in California. Although we are discussing each EPAct standard in relation to our current regulatory framework, it is instructive to consider a more competitive view of the world, because of the impending changes. We commenced the restructuring proceeding because of our unanimous belief that as the electric services industry moves toward a more competitive model, command and control regulation is no longer appropriate. We stated in the order instituting the rulemaking and investigation,

> "Some suggest that EPAct offers states and the nation a conflicted vision. This alleged conflict appears to stem from EPAct's clarity of vision with respect to increased reliance on competition as the means to increase benefits for consumers on the one hand, and its encouragement of integrated resource planning on the other. Some see competition as fundamentally incompatible with government-sponsored central planning, which is how many have come to view integrated resource planning (IRP). We disagree that robust competition and rational IRP cannot co-exist."

In D.95-05-045, we issued two policy proposals for further comment in our restructuring proceeding, one proposing competition through the formation of a mandatory wholesale power pool, the other proposing competition through phased-in direct access (more commonly known as retail wheeling). Both proposals affirm that a government-sponsored central planning resource procurement process is not appropriate in a competitive environment, but that some form of IRP may not be inconsistent with whatever market structure is eventually adopted. Most importantly for the purposes of this decision, both proposals acknowledge that renewable sources of energy and energy efficiency programs have an important role in our energy policy, both to diversify our generation resources, lower consumer bills, ensure environmental quality, and minimize the need for new generation. These goals are reaffirmed, although the focus changes from command-and-control regulation to reliance

competition and market forces when possible. We will continue the dialogue on these issues as the restructuring proceeding develops.

Gas Utilities

For our gas utilities, parties also agree that no further action is needed in terms of implementing this section of EPAct. In D.92-12-058, 47 CPUC 2d 438, we adopted a marginal costing method for gas utilities. In I.86-06-005, we identified LRMC as a cornerstone of our gas restructuring agenda to address fundamental changes taking place in the natural gas industry. In D.92-12-058, we recognized that an appropriately planned system must meet customers' needs at the lowest total cost. We required our utilities to make substantial progress in meeting our objective of a least cost planning process, and specified that cost-effective DSM programs must be included in the planning process. General rate cases have been identified as the appropriate forum in which to examine gas industry resource planning under our current regulatory environment, and we have outlined specific requirements for resource planning purposes.

We conclude that this Commission has fully considered the requirements of the IRP standard and no further implementation is necessary.

2.2 Equal Treatment Standard

Parties agree that the DSM investment standards of Section 111 and Section 115 have been adequately addressed in the DSM proceeding. D.92-02-075, 43 CPUC 2d 316, provided guidance on policy rules related to shareholder incentives first established in D.90-08-068, 37 CPUC 2d 346 and D.90-12-071, 38 CPUC 2d 507. We affirm as a threshold issue that the purpose of a DSM incentive mechanism is to offset financial and regulatory biases that favor supply-side resources. Our policy decisions in the DSM proceeding have been carefully crafted to promote cost-effective investments in energy efficiency by both gas and electric utilities, thereby aiding us in pursuing our goal for resource procurement, i.e.,

least-cost, safe, reliable, environmentally sensitive energy services for our ratepayers. (D.92-02-075, 43 CPUC 2d at 321.)

Our investor-owned utilities have been providing programs designed to encourage customers to implement cost-effective DSM programs since the mid-1970s. In 1990, we observed that utility commitment to these programs was decreasing and potential ratepayer benefits were likely to be lost. At that point, we began to experiment with various types of performance-based incentive mechanisms for DSM. For those programs that provide resource benefits (i.e., that avoid or delay more costly supply-side investments), we experimented with various forms of incentive mechanisms that share the savings between ratepayers and shareholders. For programs that served equity concerns or provided informational services, we adopted performance adder mechanisms. Under these early mechanisms, earnings were based on parameters designed to encourage broad customer participation. When we first established shared-savings mechanisms, the methods and protocols for measuring per-unit savings from DSM were still in the early development stages. As a result, these preliminary incentive mechanisms did not require adjustment of forecasted per-unit savings after installation (or "ex post") by the results of measurement studies conducted after program implementation. By 1993, however, measurement and evaluation had reached a stage where specific ex post protocols could be adopted. In D.93-05-063, we established ex post measurement protocols for measuring per-unit savings after program implementation, both in terms of the first-year load impacts and the persistence of those impacts over time. Earnings are now authorized and recovered in four equal installments over a 7- to 10-year period, based on measurement results. (49 CPUC 2d 327, 332.)

In D.93-09-078, we evaluated the accomplishments of our experimental incentive approach and concluded that this approach

should continue into the future under the current regulatory framework. Under traditional ratemaking treatment, California has effectively decoupled rates from sales (through our Electric Revenue Adjustment Mechanism (ERAM) and our Core Fixed Cost Account (CFCA) for residential and small commercial customers on the gas side). In addition, we determined that shareholder incentives are a necessary component of a least-cost regulatory plan (under our current framework) to ensure a sustained utility DSM effort. (51 CPUC 2d 371, 391.)

In D.94-10-059, we adopted the next generation of shared-savings incentive mechanisms, based on what we learned during the experimental period and incorporating the ex post measurement protocols into both the earnings and penalty calculations for future shared-savings mechanisms. In designing these mechanisms, we made specific policy judgments in evaluating whether DSM risks and rewards are generally comparable to those associated with supply-side alternatives. For the first time, utilities must guarantee that ratepayers pay no more for each portfolio than the supply-side resources that DSM is designed to replace. This mechanism, coupled with the measurement and evaluation protocols adopted in D.93-05-063, substantially shifts DSM performance risk from ratepayers to shareholders.

We specifically addressed Sections 111(a)(8) and 115(b)(4) in D.94-10-059. The comparison of profitability required by the federal standards is similar to our interim rules on supply-side comparability. However, as we stated in D.94-10-059:

> "We have learned in this proceeding that such comparisons are difficult to make, given the differing performance, earnings and investment characteristics of demand and supply-side resources. In addition, the specific risk/reward features of the DSM incentive mechanism should be considered in establishing DSM earnings opportunity.
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> "Taking all of these considerations into account, we have adopted an earnings rate that

afforded to comparable supply-side investments. We conclude that our adopted shared-savings mechanism is consistent with the federal standard, but based on a broader set of factors than the profitability guideline articulated in that standard. We believe that it is appropriate to consider a broader set of factors, given the complexity and diversity in our ratemaking treatment of both supply and demand-side resources." (D.94-10-059, mimeo, 136, 137).

Our adopted incentive mechanism anticipates the EPAct standards, and indeed goes beyond those requirements. Therefore, we agree with the parties who have filed comments in this proceeding: no further action by this Commission is needed.

2.3 Energy Efficiency Investments in Power Generation and Supply

Again, parties generally agree that the Commission has actively encouraged electric utilities to make cost-effective investments to improve generation, transmission, and distribution efficiencies and that no additional steps are necessary. DRA notes that the fundamental question of efficient operation of the utility system has been raised in the context of restructuring and the move toward performance-based regulation.

Ordering Paragraph 5 of D.90-08-068 required utilities to submit a report addressing supply system energy efficiency. (37 CPUC 2d at 369-370.) Our utilities identified several programs that improve the efficiency of their systems, and noted that such improvements are evaluated and undertaken in the normal course of business. Examples of on-going programs include conservation voltage reduction programs, low-loss distribution transformers, upgrades to the generation system, and programs to reduce losses of natural gas to the atmosphere. New technology and capital expenditures are evaluated according to cost-benefit ratios. Allied Signal recommends that certain incentives be explored in

connection with system efficiencies, including providing more flexible rate treatment or an increased rate of return as provided for in PU Code § 454.3 for certain technologies.

Utility requests for expenditures in these areas are scrutinized in our general rate case proceedings. These are the appropriate forums for further consideration of utility investments in energy efficiency of power generation, transmission, and distribution. No further action on the part of this Commission is necessary to implement this standard.

2.4 Impact of Energy Efficiency Standards on Small Businesses

Most parties believe that our continuing oversight and review of DSM programs ensure that small businesses will be able to compete on an equal footing in the DSM marketplace. DRA and TURN disagree, although TURN acknowledges that greater reliance on bidding programs should help to mitigate utility market power in this area.

An integral part of our DSM proceeding was the competitive procurement of DSM programs, referred to generally as "DSM pilot bidding." We directed utilities to develop and present pilot programs for consideration, consistent with the mandates of PU Code § 747.[4]

[4] PU Code § 747 requires that one or more energy utilities implement pilot programs to test the ability of DSM bidding to deliver benefits to utility customers, separate from any generation resource bidding system; the feasibility of an integrated bidding system that includes both generation resources and DSM programs; and a program of competitive DSM bidding auctions for gas utilities. See D.92-03-038, 43 CPUC 2d 423; D.92-09-080, 45 CPUC 2d 541; D.92-12-050, 47 CPUC 2d 72; and D.93-02-041, 48 CPUC 2d 199, for policy discussions and descriptions of each utility's approved DSM bidding pilot.

DRA points out that both Business & Professional Code § 7042.1 and the Chapter 984 of the Statutes of 1983 mandate that the Commission regulate the delivery of DSM programs, in general, in a manner that is competitive and free from the potential dominance of regulated electrical and gas corporations. DRA also reminds us that for purposes of both state and federal antitrust law, the State of California has a clearly articulated policy in favor of promoting competition in the energy conservation industry and preventing the dominance of the regulated utilities. DRA also believes that it is essential to fully address the protection of small businesses through DSM policy in the DSM proceeding because of a risk of losing state action immunity for any potential antitrust impacts from DSM programs as implemented under current Commission policy.

The consideration of competition is particularly pertinent to our oversight of utility activities in the DSM market. By enacting Chapter 984 of the Statutes of 1983, the Legislature stated its intention that public utility regulation be based on the principle that the energy conservation industry should be allowed to develop in a competitive manner. Our own policies have echoed the Legislature's intent to foster a competitive market in DSM services. We have authorized utilities to initiate programs that reduce the informational and financial barriers inhibiting the implementation of cost-effective DSM in the private market. These programs were authorized with the intent of fostering competition. We continue to regularly reassess utility involvement in DSM to ensure that it fosters, rather than impedes, private market development. We recognize our responsibility in ensuring that utility programs are designed and implemented in ways that acknowledge and accommodate changes in the marketplace. We have long recognized that the DSM market is dynamic and that utility programs must evolve as part of a continual

learning process. Accordingly, we have given the utilities flexibility to modify Commission adopted expenditure levels and program designs in order to accommodate market changes. Utilities also have the flexibility to subcontract with third parties to deliver DSM services, and are expected to do so in ways that maximize program effectiveness and efficiency. Consistent with Chapter 984 and our own stated objectives, we expect utilities to use their program management discretion in ways that foster a competitive market in DSM. The introduction of DSM shareholder incentives does not change our expectations, and those of the Legislature, that regulated utilities will involve themselves in DSM markets in a procompetitive manner, and will extricate themselves from market sectors where their involvement is no longer necessary. (45 CPUC 2d at 564.)

The specific issue of utility interface with private DSM markets can be assessed and monitored in several Commission forums. The potential impact of planned utility DSM activities on competition can most effectively be evaluated in our general rate case proceedings, where we consider DSM funding requests. In D.92-09-080, we required our utilities to present testimony, in all future funding proceedings, on how their proposed DSM programs interface with private market activities and foster competition in DSM markets. (45 CPUC 2d at 598.) We will use this information in our evaluation of utility DSM funding proposals, in order to ensure that Commission approved programs foster competition and do not negatively impact small business.

Instances where the utility is using its flexibility in a manner inconsistent with our policies can be brought to our attention by our complaint procedures. We will also initiate investigations, when appropriate.

In D.94-10-059, we concluded that certain assertions of the anticompetitive impacts of the adopted shareholder incentive mechanisms were without merit. The implication of these arguments

was that all utility-sponsored DSM programs must be put out to bid before incentives can be paid, or else utility DSM programs are anticompetitive. We rejected a similar position in D.92-09-080 (45 CPUC 2d at 561-565). The ability of energy service companies to cost-effectively augment or replace utility DSM activities is currently being tested in our bidding pilot programs, consistent with Legislative requirements. Pursuant to PU Code §747, the Commission Advisory and Compliance Division (CACD) has filed an evaluation of the DSM bidding pilot programs which examines the relationship between utilities and third parties in a competitive bidding environment.[5] Further consideration of competitive and antitrust issues will be assessed in future phases of the DSM proceeding.

Therefore, we believe that no further action on the part of this Commission is necessary to ensure that competition in the DSM marketplace continues to thrive and that small businesses are adequately protected by our current practices and procedures.

3. Title VII of the EPAct

Title VII of EPAct introduces EWGs as a potential new source of electric generation capacity.[6] These entities are exempt from the requirements of PUHCA so long as they have applied for and received determinations from the Federal Energy Regulatory Commission (FERC) that they are in the business of owning or operating "eligible facilities" (defined as facilities used exclusively to generate electricity for sale at wholesale). Title VII requires a state commission to approve certain

5 Evaluation of DSM Bidding Pilot Projects in California, prepared for CACD by the Wisconsin Energy Conservation Corporation, filed on July 21, 1995.

6 Other standards relating to EWGs were addressed in D.93-11-080 and D.93-12-022.

transactions between EWGs and affiliated utilities (Section 711) and certify to the Securities and Exchange Commission (SEC) that the commission has the authority and resources to protect ratepayers from possible harmful effects of foreign affiliate diversification and that it intends to exercise that authority (Section 715).

3.1 Section 711: EWGs and Affiliated Utilities; Hybrid Facilities.

Congress allowed EWGs to sell to affiliated utilities if each state commission with jurisdiction over the buying utility's retail rates makes several determinations. The commission must determine that it has sufficient authority, resources and access to books and records to exercise its duties to oversee affiliate transactions. The commission must also determine that the affiliated sales will benefit consumers, will not violate state law, will not provide the EWG any unfair competitive advantage by virtue of its affiliation or association with the electric utility company, and is in the public interest. The commission must make comparable determinations before an unregulated affiliate of an EWG may purchase power from the EWG for resale to an affiliated regulated utility.

Similarly, generating facilities currently in a utility's ratebase may be transferred to EWG status only if the state commission determines that the conversion will benefit consumers, is in the public interest, and does not violate state law. State commissions must also approve hybrid facilities which are partially owned by a EWG and partially owned by its affiliated utility. Hybrid facilities with no affiliated relationship do not require state commission approval.

Parties recommend that the Commission consider applications for affiliated sales, conversion of existing rate-based property or hybrid facilities on a case by case basis rather than crafting generic guidelines at this time. Most parties

believe that this will allow greater opportunities for Commission review. (PG&E notes that the EPAct requirements under this section are subsumed under our prudence reviews and the requirements of PU Code Section 851. Parties are unanimous in their recommendation that separate applications requesting such authorizations be filed, rather than being consolidated with other proceedings. (We concur)

3.1.1 Affiliate Transactions

Most of our respondent utilities recommend that such requests be evaluated on a case by case basis. Only SDG&E recommends that generic guidelines be promulgated at this time. DRA, TURN, and the DOD oppose affiliated sales, because transactions between a utility and its affiliate create an inherent and unmanageable conflict of interest. In addition, TURN believes that such activities would create an enormous workload for Commission staff and for that reason alone should be prohibited. DRA recommends that if such transactions are allowed, separate applications should be filed and each application should be addressed on a case-by-case basis. All parties agree that these applications should not be consolidated with other proceedings. The issues raised are important enough, as TURN points out, to warrant special Commission attention.

While both DOD and DRA oppose the practice of allowing affiliate transactions, both recommend that the Commission follow fundamental guidelines mandated by EPAct, if affiliate transactions are allowed. DOD also recommends that we consider whether allowing such transactions furthers the goal of introducing competition into the resource procurement process, while at the same time treating potential competitors in an evenhanded manner. DRA agrees and recommends that further guidance can be found in several Commission decisions on similar issues.

We have long been concerned with the importance of arms-length affiliate transactions and have promulgated a variety of guidelines in this area

In D.93-02-019 we adopted interim reporting requirements for utility affiliate transactions which are widely applicable. (48 CPUC 2d 163.) [7] In addition, several PU Code sections are applicable and provide important consumer protections. [8] Such protections are essential as we move into a more competitive era. As TURN reminds us, affiliate transactions require more, not less, regulatory scrutiny. Fair competitive practices must be ensured and a level playing field must be maintained. In particular, we emphasize that this Commission has never condoned self-dealing, nor will we in the future. Edison stated in its comments, "In essence, the Act prohibits self dealing in power sales from EWGs, but allows the Commission to override that prohibition on a case by case basis." We have stated clearly in the past that we would respond to the potential or appearance of a conflict of interest to protect the utility's ratepayers and the development of a competitive market from any conflicts of interest or the potential of such conflicts (D.90-09-088, 37 CPUC 2d at 579). There is no statement in EPAct that should be construed to change this duty and obligation.

However, we agree with Edison that the generic approach is not well suited to today's rapidly changing environment. We will require our utilities to file separate applications to request our approval of such transactions and require that, at a minimum, the guidelines promulgated in EPAct and our prior decisions be met.

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7 See also D.88-01-063, 27 CPUC 2d 347; D.88-12-083, 30 CPUC 2d 189; D.91-05-028, 40 CPUC 2d 159; D.90-09-088, 37 CPUC 2d 488; D.91-12-076, 42 CPUC 2d 645; D.93-03-021, 48 CPUC 2d 352; and D.94-03-050, in which we discuss concerns with affiliate transactions.

8 PU Code §§ 314, 532, 587, 797, and 851 are particularly relevant.

In addition, we remind the utilities that they bear the burden of proof in such matters to prove by a preponderance of evidence that such transactions are in the public interest.

While SDG&E suggests that general policy guidelines should be crafted for case by case applications to the Commission, which would then be treated on an expedited basis, we agree with DRA and DOD that such guidelines are provided by EPAct itself. No further general guidance is necessary at this time. SDG&E acknowledges that it is risky to define in detail the factors that may vary significantly depending on particular scenarios.[9] Finally, the CMA suggests that the Commission may wish to consider adopting regulations which would prohibit affiliates from sharing information, employees, management, etc. We believe that such protections are built into D.88-01-063 and other decisions. However, we will mindfully reevaluate our position on establishing general guidelines in this area as we gain more experience with such applications.

Both Edison and DRA affirm that transactions between Edison and its affiliate qualifying facility (QF) entities are not allowed under the terms of the settlement adopted in D.93-03-021, without specific approval by the Commission. (48 CPUC 2d at 360.) While there are four exceptions to the general prohibition on sales to Edison from any subsidiary of SCEcorp (the parent corporation), none of these exceptions will allow Edison to purchase power from an EWG in which SCEcorp, or any subsidiary of SCEcorp, owns an interest. Edison notes that Section 10.4 of the agreement provides

9 We note that SDG&E filed Application (A.) 94-11-013 to request authorization to create a holding company. This application is pending, with a decision expected by the end of the year. For our purposes today, it is important to note that under discussion in that proceeding are the conditions which would be imposed on the holding company structure, should it be allowed, many of which are similar to those addressed in D.88-01-063.

for an amendment to these restrictions if agreed to by the parties and approved by the Commission.[10] These restrictions should continue under the terms of the settlement agreements so that ratepayers and the competitive marketplace continue to be protected. Again, this is an example of the power of this Commission to adequately monitor affiliate transactions.

3.1.2 Gain on Sale

The transfer of utility property to EWG affiliates also raises the issue of who benefits from any gain on sale of that property. DRA and TURN recommend that all gains on sales or transfers of existing rate based property accrue to ratepayers and that benefits to ratepayers be maximized. Other parties recommend that we treat the gain on sale issue on a case by case basis. CMA points out that allowing a utility to spin off heavily depreciated, but still useful generating facilities to an EWG (particularly an affiliated entity), who would then sell power back to the utility at market prices which could exceed cost-based levels for the transferred facilities, may well deprive ratepayers of the full benefits of the assets they have paid for over the years. Edison argues that the long-term interests of ratepayers and shareholders are not aligned when gains on sale of rate based property accrue to ratepayers. SDG&E recommends that transfers of assets be evaluated on a long-term benefit basis and states that such transfers may not result in a realized gain.

The sale or other transfer of utility property and the ratemaking treatment relating to gains and losses resulting from

[10] See D.84600; D.90405, 1 CPUC 2d 644; D.82-12-121, 10 CPUC 2d 647; D.83-12-065, 13 CPUC 2d 629; D.85-06-023, D.86-11-018, 19 CPUC 2d 161; D.86-01-026, 20 CPUC 2d 237; and D.88-08-061, 29 CPUC 2d 63.

[11] For example, in D.89-12-057, 34 CPUC 2d 199, we determined that the gains from the sale of nondepreciable property be flowed through to ratepayers, while in D.87-12-066, 26 CPUC 2d 392 we allocated certain gains to both ratepayers and shareholders.

such transactions are important issues for Commission consideration.[10] Most issues regarding gains on sale of utility property arise from compliance with PU Code § 851, which requires Commission authorization prior to the sale, transfer, lease, or consolidation of utility property. Other transactions not covered by § 851 generally consist of property which was transferred from Utility Plant In Service accounts or from Plant Held for Future Use (both ratebase accounts) to Non-Utility Plant accounts and subsequently disposed of, either by selling the property outright or by transferring it to a nonutility affiliate.

The Commission has often evaluated gain on sale issues on a case by case basis and allocated gain on sale to ratepayers and shareholders over the past several years. In general, gains and losses on sales or transfers of existing operating property accrue to ratepayers.[11] However, we have found that there are specific circumstances which warrant a reasonable sharing of the benefits of the gain on sale between ratepayers and shareholders. For example, in D.90-11-031, 38 CPUC 2d 166, we found it appropriate to allocate the principal amount of the gain to offset future costs of transfers headquarters facilities, because ratepayers had borne the burden of risks and expenses while the property was in ratebase. At the same time, we found that it was equitable to allocate a portion of the benefits from the gain on sale to shareholders in order to provide a reasonable incentive to the utility to maximize the proceeds from

10 See D.84600; D.90405, 1 CPUC 2d 644; D.82-12-121, 10 CPUC 2d 647; D.83-12-065, 13 CPUC 2d 619; D.85-06-023, D.85-11-018, 19 CPUC 2d 161; D.86-01-026, 20 CPUC 2d 237; and D.88-08-061, 29 CPUC 2d 63.

11 For example, in D.89-12-057, 34 CPUC 2d 199, we determined that the gains from the sale of nondepreciable property be flowed through to ratepayers, while in D.87-12-066, 26 CPUC 2d 392 we allocated certain gains to both ratepayers and shareholders.

selling such property and compensate shareholders for any risks borne in connection with holding the former property. (38 CPUC 2d at 187-198.)

In sales involving condemnation proceedings or the threat of condemnation, the Commission has found that the risk of gain or loss is properly borne by utility shareholders. Typically, these transactions involve the sale of a complete utility company or of a discrete operating unit.

In general, we affirm our established policy of allowing gain on sales, transfers or conversions of useful ratebased property to accrue to ratepayers. Since we cannot anticipate each circumstance which may arise in such applications, we will review each transaction on a case-by-case basis. DRA has properly pointed out that in applications seeking the conversion of a utility's property to nonutility status, or in which the utility is seeking treatment of utility-owned or affiliated EWGs, utility participation is analogous to that of QF representatives, i.e., they are seeking Commission treatment of resources which will not be owned by ratepayers and which may provide unregulated profits to shareholders. DRA suggests that it may not be appropriate, therefore, to have utilities' litigation costs in these proceedings funded by ratepayers, since ratepayers do not pay for the costs of participation of other parties who are similarly situated. In the interests of providing a level playing field, we agree that this is

12 In D.89-07-016, 32 CPUC 2d 233, the Commission found that for sales of utility assets within the scope of R.88-11-041, any gain on sale should accrue to shareholders, with certain provisos. This rulemaking was explicitly limited to the allocation of gains and losses when a distribution system of a public utility is sold to a municipality or some other public or governmental entity and the sale of the system is concurrent with the utility being relieved of and the municipality or other agency assuming the obligation to serve.

an issue to be considered. We expect parties to brief these issues in any such applications brought before us.

3.2 Section 715: Exemption of Foreign Utility Affiliates from PUHCA Based on State Commission Certification to the SEC

Section 715 adds a new Section 33 to PUHCA. Section 33(a) exempts foreign utility companies from all provisions of PUHCA so long as every state commission with jurisdiction over a public utility company that is an associate or affiliate company of the foreign utility company has certified to the SEC that it has the authority and resources to protect ratepayers subject to its jurisdiction and that it intends to exercise its authority. The certification requirement is deemed satisfied if the state commission, prior to October 24, 1992, had determined that ratepayers of the public utility company are adequately insulated from the effects of diversification, and that the diversification would not impair the ability of the commission to regulate effectively the operations of such company.

SCEcorp, the parent of Edison, is actively investing in foreign utility companies through its subsidiary and Edison affiliate, Mission Energy Company. SCEcorp's position, in filings with both the SEC and this Commission since January 1993, is that its holding company decision, D.88-01-063 (27 CPUC 2d 347), meets the requirement of certification on the basis of prescribed conditions of general applicability.[13]

On the whole, parties believe that D.88-01-063 along with the Commission's general powers to regulate are sufficient to meet the certification requirements under EPAct.[12] In R.93-06-001, we solicited comments from parties on the issue of exempting foreign

[12] In R.93-06-001, we

[13] Certification was made for Pacific Enterprises by letter dated October 26, 1994; PG&E by letter dated July 6, 1995; and for PacifiCorp by letter dated October 5, 1995.

utility affiliates from PUHCA based on our certification to the SEC that we have the authority and resources to protect ratepayers in our jurisdiction and that we intend to exercise this authority. It is critical that our ratepayers be insulated from any foreign utility diversification. With this in mind, we sought comments on the following issues:

Does D.88-01-063 meet the certification requirement for SCE corp under EPAct?

Are there special considerations that the Commission should address for foreign affiliates?

Do conditions in D.88-01-063 provide the Commission with sufficient authority to protect ratepayers? For example, do the conditions ensure that the Commission has adequate access to the books and records of foreign affiliates? If not, what revised or additional conditions should be adopted?

What form of notice should the Commission require from utilities regarding newly acquired foreign utility affiliates?

The majority of the parties recommend that no further action with respect to Section 715 should be required at this time. The Commission has the authority to protect ratepayers subject to its jurisdiction from potential and actual abuses associated with affiliate transactions and has repeatedly demonstrated its intent to exercise its authority, as discussed above. Several PU code sections are applicable, with §§ 314, 587, and 797 being particularly relevant. In D.88-01-063, we adopted several

conditions to insulate Edison's ratepayers from the effect of diversification.[14] Edison states that the fifteen conditions imposed on Edison and SCEcorp remain in effect and are equally applicable to domestic and foreign diversified activities. As Edison points out, Section 33(a)(2) of PUHCA provides that each state commission has the authority to withdraw certification to the SEC prospectively.

DRA believes that, despite these safeguards, the Commission has had repeated problems regarding utility affiliates and recommends that proceedings be held to develop a full range of new requirements in this area. TURN agrees and suggests that the diminished size of our staff will impact our ability to regulate such investments. TURN does not believe that D.88-01-063 addresses the issues likely to arise as a result of foreign utility diversification.

DRA proposes that particular guidelines regarding reporting requirements be added to those promulgated in D.88-01-063 in order to fully protect ratepayers. These include following our reporting requirements for domestic affiliate transactions and requiring the reporting of foreign affiliate transactions to following the same accounting practices and conventions used in reporting domestic affiliate transactions. DRA believes that records and documentation should be maintained for a minimum of ten years to the extent they relate directly or indirectly to transactions with the utility. DRA also recommends that foreign affiliate officers and employees should be made available to the Commission for investigative and audit purposes. Edison has

14 D.88-01-063 also concludes that the adopted rules and conditions with regard to financial controls and reporting were adequate to support our regulatory function of insulating Edison's ratepayers. (27 CPUC 2d at 364.)

committed to explaining any differences in accounting conventions and providing for translations into English, if this is required.

We have conditioned our certification to the SBC upon each utility requesting such certification making the following commitments:[15]

1. Each utility must expressly affirm its understanding of our broad regulatory authority to review and audit the books and records of each utility, its subsidiaries and affiliates, including the applicability of PU Code §§ 314 and 587, Code § 314(b) permits the inspection of the accounts, books, papers and documents of an affiliated foreign utility company with respect to any transactions between that company and the regulated utility. We will require each utility, as they have so affirmed, to provide our staff, upon request, with access to such accounts, books, papers, and documents, translated into English and restated to conform with United Stated generally accepted accounting principles.

2. Each utility must affirm its understanding that it may be required by the Commission to pay the costs of any Commission-ordered outside audit of transactions between the regulated utility and an affiliated foreign utility company.

3. Each utility must confirm that it will make employees and officers of the regulated utility and of its subsidiaries and controlled affiliates with interests in foreign utility companies available to appear and testify, as necessary or required in Commission proceedings, and will bear associated costs. Each utility must also make a good faith effort to make

15 We have also conditioned our certification upon certain other agreements that are specific to particular utilities

available officers and employees of such affiliates in which it does not have a controlling interest with respect to transactions between that utility and any such foreign utility company, and will bear associated costs.

4. Each utility must expressly affirm that any costs incurred in carrying out the commitments outlined above and any other commitments with regard to the exercise of the Commission's authority to protect ratepayers in connection with investments in foreign utility companies will be borne by its shareholders and not its ratepayers.

5. Each utility must notify the Commission if it transfers any products, product rights, patents, copyrights or similar legal rights to an affiliated foreign utility company or to any affiliate which has an interest in a foreign utility company. In this case, the Commission may require the payment of a royalty in the event of such a transfer to ensure fair and reasonable compensation to ratepayers for such product or legal right.

We are satisfied that the requirements adopted in D.88-01-063 together with our regulatory powers delineated in PU Code §§ 314, 587 and 797 provide us with sufficient authority to monitor the accounting safeguards the DRA recommends. The commitments outlined above reiterate the conditions adopted in D.88-01-063. For instance, D.88-01-063 specifically requires Edison and its affiliates to keep its books in a manner consistent with generally accepted accounting principles and, where feasible, consistent with the Uniform System of Accounts. (27 CPUC 2d at 375). In addition, D.93-02-019 adopted interim rules regarding affiliate transactions which also allow us to fully monitor and review any affiliate transactions, including the internal controls and accounting safeguards that are in place (48 CPUC 2d at 174 - 175). We find, therefore, that it is not necessary to adopt additional requirements.

TURN believes that we should be concerned about the inconsistencies of utilities engaging in activities through a foreign affiliate which would not be in compliance with U.S. environmental standards, while at the same time touting its local environmental achievements. We recognize that there may well be inconsistencies in how utilities and their affiliates carry out their business practices. However, as we have stated previously, it is the duty of this Commission to ensure that ratepayers interests are advanced by focusing on the quality of actions taken by California utilities to provide "safe, reliable, nondiscriminatory and reasonably-priced utility service." (D.93-07-054 50 CPUC 2d 452, 459; D.93-11-017 52 CPUC 2d 47, 54.)

While we recognize TURN's concerns with environmental standards and fair employment practices, these issues are beyond our jurisdiction. TURN has raised a valid point in terms of the uncertainty of foreign investments and potential political upheavals. We believe we can address these concerns by monitoring the foreign investments of utilities, as discussed above. Moreover, because the utilities must answer to shareholders, as well as this Commission, we would expect that utilities will monitor the risk and reward of such investments carefully.

DRA recommends that utilities provide the Commission with advance notice of prospective investments in foreign utility affiliates that are above a certain minimum.[16] By requiring this notification, DRA believes that the Commission's ability to protect ratepayers from the potential adverse impacts of foreign utility affiliate investments is strengthened. The Commission would then be able to withdraw or revise the certification provided to the SEC prospectively as required by Section 715, should we find the

[16] In DRA's comments, a minimum level of $100 million was indicated in the text; $1 million in a footnote to that text.

investment is detrimental to consumers. In particular, DRA recommends that the following information be provided:

1. Description of the foreign affiliate
2. Reason for the acquisition
3. Purchase price
4. Financial statements for the last five years
5. Names of Directors and officers for last five years
6. Number of employees
7. Past and current transactions with the utility
8. Future transactions (projected with the utility)
9. From whom the new affiliate is being acquired
10. Identity of major partners (defined as those who own 5% or more of the new affiliate)

The utilities are required to file notice with the SEC regarding investments in foreign affiliates. In addition, EPAct requires utilities to notify state commissions of the acquisition of such interests not less than 30 days after that acquisition is finalized. (PUHCA Section 33(e)(2).) We will not impose an advance notification requirement at this time. The notification required by EPAct, along with our affiliate transaction reporting requirements, will allow us to adequately review such investments and determine whether our certification to the SEC should be revised or revoked. There is no need to duplicate filings and reporting requirements, which could become burdensome for both regulators and utilities.

At this time, we shall specify how this notification is to occur, as is required under EPAct. The notice shall be in the form of a letter to the Commission's Executive Director, with copies sent to the Commission's General Counsel, the Deputy Director

(Energy and Advisory) of CACD and the Deputy Director (Energy) of DRA. The letter should describe each investment and reaffirm the commitments made to us by each utility requesting such certification.[17] The utilities should include a copy of all filings required by the SEC.

4. Title IX: Uranium Enrichment, Health, Safety and Environmental Issues

This title converts the Department of Energy's (DOE) uranium enrichment program into a federally owned corporation which will ultimately be sold to private investors. The cost of clean-up for the enrichment plants is split between the federal government and domestic nuclear utilities. Nuclear utilities, which have purchased fuel from DOE for commercial reactors since 1969, would assume roughly 30 percent of the costs. Their share would be capped at $2.25 billion over 15 years, indexed to inflation. The fees for the individual nuclear utilities would be based on the amount of enriched uranium they had purchased from the federal government over the years. State commissions are required to pass through the costs associated with fees required of utilities for the decommissioning and decontaminating of DOE's enrichment facilities. We solicited comments on the implementation of this requirement.

EPAct also removes current restrictions on nuclear decommissioning trust funds limiting "qualified" investments. With the approval of this Commission, investments can now be made in equity securities. Again, the Commission requested comments on the criteria to be used to approve these investments. Only PG&E and SDG&E commented on these issues.

17. See Pacific Enterprise's letter dated September 29, 1994, PG&E's letter dated June 15, 1995, and Edison's letter dated July 20, 1993.

SDG&E suggests that these costs be recovered in the same manner as other reasonable and necessary costs of fuel. We concur and direct the utilities to file any tariff changes necessary to recover the costs incurred under the DOE assessment in the same manner as are other fuel costs. These costs will continue to be reviewed in each electric utility's Energy Cost Adjustment Clause (ECAC) proceeding.

PG&E estimates its share of the cost responsibility for clean-up of DOE nuclear fuel enrichment facilities to be approximately $13 million. When the cost is finalized, PG&E proposes to apportion this liability between ratepayers and shareholders in proportion to the DOE enrichment services obtained for the Humboldt and Diablo Canyon facilities, respectively. We agree that this is appropriate and will require PG&E to submit this information to CACD in a detailed advice letter filing, which includes all workpapers.

SDG&E also recommends that investment issues surrounding Nuclear Decommissioning Trusts should be addressed in the continuation of the OII 86 proceeding. After EPAct was signed into law, SDG&E, PG&E, and Edison petitioned the Commission regarding investment criteria for Nuclear Decommissioning Trusts. EPAct modified certain rules applicable to qualified nuclear decommissioning trust funds by reducing the Federal tax rate applicable to such funds from the current rate of 34% to 22% in 1994 and to 20% in 1996. In addition, the legislation eliminated certain investment restrictions applicable to the trust funds, effective January 1, 1993. We have addressed these issues in OII 86. Public hearing was held on October 6, 1994, at which time the petitioners, supported by DRA, filed a Joint Recommendation, which was subject to cross-examination by the presiding Commissioner and the presiding administrative law judge. D.95-07-055 addressed the proposed investment portfolios, financial

risk, and necessary ratepayer protection. Any further action in this proceeding would be redundant.

5. Miscellaneous

Respondents and other interested parties were invited to comment on implementation of other provisions of EPAct, which require Commission implementation, but were not specified in R.93-06-001. We solicited comments, for example, on whether EPAct requires revision of any provisions of the PU Code and whether EWGs are subject to regulation as public utilities under the code.

PU Code § 216 broadly defines the term "public utility," and includes in that definition every "electrical corporation" performing service or delivering commodity to the public. Section 216 also provides for certain exceptions from these definitions, including geothermal, solar, and cogeneration facilities and those facilities selling compressed natural gas. Section 218 defines the term "electrical corporation" to include every entity owning, controlling, or managing property used to generate electricity for light, heat, or power. Section 218 provides for similar exceptions. Sections 228.5(a) and (b) exclude from the definition of "public utility" a "qualifying small power producer" as that term is defined under PURPA. This therefore exempts PURPA-type facilities from public utility regulation by this Commission.

CMA states that in the absence of a legislative extension of PU Code § 228.5 to exempt all EWGs from public utility regulation by the Commission, any EWG that does not meet the "small power production" definition under the Federal Power Act may be subject to Commission regulation as a "public utility" if it a) does not satisfy any of the statutory exemptions from the definition of "electrical corporations" and b) is determined to be providing service "to the public." CMA notes that to the extent that an EWG is determined to be holding itself out to provide service to the public at large, that EWG may be subject to

Commission jurisdiction, but only to the extent that it is not engaged in sales in interstate commerce. If the EWG is selling in interstate commerce, FERC rate regulation would preempt our jurisdiction. CMA recommends that legislative extension of Section 228.5 to all EWGs (as defined by EPAct) is appropriate.

Edison also recommends that the PU Code be revised to exclude EWGs from regulation as a public utility. PG&E notes that, as a practical matter, while PU Code § 218 broadly defines electrical corporations, regulation of EWGs would directly conflict with Federal jurisdiction over wholesale power rates. PG&E encourages us to interpret the PU Code as not requiring any regulation of EWGs, as long as they engage in wholesale sales only.

We will adopt Edison's and CMA's recommendations. We recommend that the Legislature modify the appropriate PU Code sections to clarify our regulatory powers and the applicable exceptions. Indeed, it is necessary to revise these provisions because we are constitutionally precluded from declaring a statute unenforceable or to refuse to enforce a statute on the basis that federal law or federal regulations prohibit the enforcement of such statute unless an appellate court has made such a determination. (West's Constitution of the State of California, 1A at 715.) We recommend that the following modifications occur through the legislative process, and we will work with the legislature to ensure this happens:

216(g) Ownership or operation of a facility which has been certified by the Federal Energy Regulatory Commission as an exempt wholesale generator under Section 32 of the Public Utility Holding Company Act of 1935, does not make a corporation or person a public utility within the meaning of this section solely because of the ownership or operation of such a facility.

228.5(c) The term "exempt wholesale generator" has the same meaning as found in Section 79 et seq. of Title 15 of the United States Code and Regulations enacted pursuant thereto.

"22815(d) Notwithstanding any other provision of law, an exempt wholesale generator is not a public utility subject to the general jurisdiction of the Commission solely because of the ownership or operation of the facility."

6. Conclusion

In keeping with our overarching framework of moving toward a more competitive marketplace in both the electric services industry and the gas industry, we decline any EPAct standards that would inhibit us from continuing on this path. At the same time, we provide the necessary affirmation required by EPAct that we have adequate regulatory powers in terms of monitoring affiliate transactions and investments in foreign utilities. We adopt SDG&E's and PG&E's recommendations in regards to the ratemaking treatment for recovery of EPAct mandated costs related to uranium enrichment facilities. Finally, we recommend modifications to the PU Code to clarify our regulation of EWGs, which should be enacted through the legislative process.

Findings of Fact

1. EPAct requires state commissions to consider various standards which are added to PURPA and PUHCA.

2. Our findings in this proceeding are made within the current regulatory framework.

3. Utilities in both the electric and gas industries are increasingly facing a competitive market.

4. Section 111(a) and Section 115 of EPAct add standards to PURPA which address integrated resource planning and investments in energy efficiency for electric and gas utilities, respectively.

5. Both Section 111 and Section 115 require that if this Commission determines to implement these standards, the Commission must protect small businesses engaged in DSM measures.

6. The IRP standards have been addressed in I.89-07-004 for our electric utilities, in I.86-06-005 for our gas utilities and in R.91-08-003/I.91-08-002, our consideration of DSM policies.

7. No additional consideration is necessary for the smaller utilities which we regulate. IRP and DSM issues are considered as part of Pacificorp's and Sierra Pacific's general rate cases.

8. Our goal for resource procurement is the provision of least-cost, reliable, environmentally sensitive, and safe electric services.

9. The DSM investment standards of Section 111 and Section 115 of EPAct have been adequately addressed in R.91-08-003/I.91-08-002.

10. The purpose of a DSM shareholder incentive mechanism is to offset financial and regulatory biases that favor supply side resources.

11. Our policy decisions in the DSM proceeding have been carefully crafted to promote cost-effective investments in energy efficiency by both gas and electric utilities.

12. In D.95-05-063, we adopted rigorous ex post measurement protocols for measuring per-unit savings after DSM program implementation in terms of both first-year load impacts and the persistence of those savings over time.

13. We concluded in D.93-09-078 that DSM shareholder incentives are a necessary component of a least-cost resource procurement plan, under the current regulatory framework, to ensure a sustained utility DSM effort.

14. ERAM, the CFCA, and the NCFCA have removed a significant regulatory disincentive to increased DSM efforts.

15. In D.94-10-059, we adopted a portfolio-based incentive mechanism which includes a cost-effectiveness guarantee, i.e., utilities must guarantee that ratepayers pay no more for each DSM portfolio than the supply-side resources that DSM is designed to replace.

16. In adopting the earnings rate for this shareholder incentive mechanism, we concluded that it is within the range of

earnings opportunity afforded to comparable supply-side investments.

17. D.90-08-068 required utilities to submit a report addressing supply system energy efficiency.

18. Supply system energy efficiency programs are evaluated and undertaken in the normal course of utility business.

19. Utility requests for expenditures for supply system energy efficiency improvements are scrutinized in our general rate case proceedings.

20. DSM programs pilot bidding are an integral part of our DSM proceeding.

21. The Legislature enacted Chapter 984 of the Statutes of 1983 to state its intention that the energy conservation industry be allowed to develop in a competitive manner.

22. We regularly assess utility involvement in DSM to ensure that it fosters, rather than impedes, private market development.

23. The potential impact of planned utility DSM activities on competition can be evaluated most effectively in our general rate case proceedings.

24. Title VII of EPAct introduces EWGs as a potential new source of electric generation capacity.

25. By Section 711 of Title VII, a state commission is required to approve certain transactions between EWGs and affiliated utilities, if the commission determines that it has sufficient authority, resources, and access to books and records to exercise its duties to oversee affiliate transactions.

26. EPAct provides general policy guidelines, in that each commission must also determine that the affiliated sale will benefit consumers, will not violate state law, will not provide the EWG any unfair competitive advantage, and is in the public interest.

27. In D.93-02-019, we adopted interim reporting requirements for utility-affiliate transactions which are widely applicable to the affiliate EWG transactions discussed in this decision.

28. PU Code §§ 314, 532, 587, 797, and 851 provide important consumer protections in terms of affiliate transactions.

29. D.88-01-063 also provides important protections which prohibit affiliates from sharing information, employees, management, etc.

30. Edison and its affiliate QF entities are not allowed to enter into transactions without specific approval by this Commission, under the terms of the settlement adopted in D.93-02-021.

31. The sale or other transfer of utility property and the ratemaking treatment relating to gains and losses resulting from such transactions is an important issue for Commission consideration. The Commission has allocated gain on sale benefits to ratepayers and shareholders. We review such transactions on a case-by-case basis.

33. Section 715 adds a new Section 33 to PUHCA which exempts foreign utility companies from all provisions of PUHCA so long as each applicable state commission has certified to the SEC that it has the authority and resources to protect ratepayers under its jurisdiction and that it intends to exercise its authority.

34. In D.88-01-063, we adopted several conditions to insulate Edison's ratepayers from the effect of diversification.

35. The requirements adopted in D.88-01-063 along with the Commission's general powers to regulate are sufficient to meet the certification requirements under EPAct.

36. We have provided the certification described in Section 715 of EPAct for Pacific Enterprises and SoCalGas by letter dated October 26, 1994, which was conditioned on certain agreements and included ratepayer protections.

Section 715 of EPAct for PG&E by letter dated July 6, 1995, which was conditioned on certain agreements and included ratepayer protections.

38. Title IX converts the DOE's uranium enrichment program into a federally owned corporation which will ultimately be sold to private investors.

39. States commissions are required to pass through the costs associated with fees required of utilities for decommissioning and decontaminating DOE's enrichment facilities.

40. EPAct removes current restrictions on nuclear decommissioning trust funds' qualified investments.

41. D.95-07-055 addressed the proposed investment portfolios, financial risk, and necessary ratepayer protection in terms of the Nuclear Decommisioning Trust.

42. PU Code § 216 broadly defines the term "public utility," as every "electrical corporation" performing service or delivering the commodity to the public.

43. PU Code § 216 provides for certain exceptions from this definition, including geothermal, solar, and cogeneration facilities and those facilities selling compressed natural gas.

44. PU Code § 218 defines "electrical corporation" to include every entity owning, controlling, or managing property used to generate electricity for light, heat, or power, provides for the exceptions outlined above, and also exempts a qualifying small power producer as that term is defined under PURPA.

Conclusions of Law

1. States are to consider, but are not required to adopt, the standards contained in Sections 111, 115, 711, 715, and Title IX of EPAct.

2. The findings in today's decision are made with reference to the Commission's current regulatory framework for the Electric utilities

3. We have fully considered the requirements of the IRP and energy efficiency standards, and no further action by this Commission is necessary to implement Section 111 and Section 115 of EPAct.

4. PU Code §§ 314, 532, 587, 797, and 851 grant us the statutory authority to effectively oversee utility-affiliate transactions.

5. Our utilities should file separate applications to request approval of the utility affiliate transactions addressed in Title VII of EPAct.

6. EPAct's general policy guidelines for utility-EWG affiliate transactions should be adopted.

7. Utilities bear the burden of proof to prove by a preponderance of evidence that utility-EWG affiliate transactions are in the public interest.

8. The restrictions on transactions between Edison and its affiliated QF entities, as outlined in D.93-03-021, should continue.

9. The recipients of the gain or loss on sale or transfer of utility property should be evaluated on a case-by-case basis.

10. The conditions adopted in D.88-01-063 and the broad regulatory powers granted to us by PU Code §§ 314, 587, and 797, among others, provide us with sufficient authority to fully protect ratepayers from any adverse effects of utility investment in foreign affiliates.

11. Ratepayers' interests are advanced by focusing on the quality of actions taken by California utilities to provide safe, reliable, nondiscriminatory, and reasonably priced utility service.

12. Consistent with the requirements of EPAct, utilities should provide the Commission with notice of investments in foreign utility affiliates within 30 days of the consummation of such transactions.

13. The notification provisions adopted today are reasonable and sufficient to allow the Commission to withdraw or revise the

certification provided to the SEC, if necessary, as required by Section 715.

14. Costs associated with fees for the decommissioning and decontaminating of DOE's uranium enrichment facilities should be recovered in the same manner as other reasonable and necessary costs of fuel.

15. The reasonableness of such costs should continue to be reviewed in each electric utility's ECAC proceeding.

16. PG&E's proposal to allocate these costs between ratepayers and shareholders according to the proportion of DOE enrichment services obtained for the Humboldt and Diablo Canyon facilities, respectively, is reasonable.

17. While PU Code § 218 broadly defines electrical corporations, regulation of EWGs would directly conflict with Federal jurisdiction over wholesale power rates.

18. Modification of the PU Code is necessary at this time.

19. No new standard should be adopted as a result of our consideration of the EPAct standards analyzed in today's decision.

20. To eliminate unnecessary uncertainty, this decision should be effective today.

O R D E R

IT IS ORDERED that:

1. Having considered the standards contained in Sections 111, 115, 711, 715, and Title IX of the National Energy Policy Act of 1992 (EPAct) regarding integrated resource planning, energy efficiency investments, utility transactions with exempt wholesale generator affiliates, investments in foreign utility affiliates, nuclear decommissioning and decontamination fees related to uranium enrichment facilities, and investments in Nuclear Decommissioning Trusts, the Commission deems these standards unnecessary or

inappropriate at this time, and accordingly declines to adopt any of them.

Any utility investing in foreign utility affiliates pursuant to Section 715 of EPAct shall provide notification of such transactions within 30 days after the consummation of the acquisition of that interest. The notification shall be in the form of letter to the Executive Director of this Commission, with copies to the General Counsel, Deputy Director (Energy and Advisory) of the Commission, Advisory and Compliance Division, and Deputy Director (Energy) of the Division of Ratepayer Advocates. The letter shall describe each investment and reaffirm the commitments made to us by each utility requesting our certification to the Securities and Exchange Commission (SEC). Any such notification shall include a copy of the required filings made with the SEC.

This order is effective today.

Dated December 6, 1995, at San Francisco, California.

DANIEL Wm. FESSLER
President
P. GREGORY CONLON
JESSIE J. KNIGHT, JR.
HENRY M. DUQUE
JOSIAH L. NEEPER
Commissioners