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APR 24 1992

Decision 92-04-045 April 22, 1992

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

| | |
|---|---|
| Order Instituting Investigation on the Commission's own motion to implement the Biennial Resource Plan Update following the California Energy Commission's Seventh Electricity Report. | I.89-07-004 (Filed July 6, 1989) |
| And Related Matters. | Application 91-02-092<br>Application 91-07-004<br>Application 91-08-028 |

(See Decisions 90-03-060, 91-06-022 and 91-10-039 for appearances.)

(See Attachment 7 for additional appearances.)

**INTERIM OPINION, RESOURCE PLAN PHASE: BIDDING FOR NEW GENERATION RESOURCES**

## INTERIM OPINION, RESOURCE PLAN PHASE: BIDDING FOR NEW GENERATION RESOURCES

### 1. Summary

In today's decision, we find that respondents Pacific Gas and Electric Company (PG&E), San Diego Gas & Electric Company (SDG&E), and Southern California Edison Company (Edison) all have current need of new or additional electric generation.[1] We identify certain resources that could meet those needs, consistent with our criteria for environmentally sensitive least-cost planning, and we direct the respondents to solicit bids by qualifying facilities (QFs) to defer or avoid those resources pursuant to our Standard Offer 4 auction process.

Our finding of need is also consistent with the California Energy Commission's (CEC) "integrated assessment of need" adopted in Chapter 6 of its 1990 Electricity Report (ER-90). Specifically, SDG&E and Edison will solicit bids for amounts of capacity that are in both cases within the amounts that the CEC says these utilities should acquire now. PG&E will solicit bids from QFs on the San Francisco peninsula to defer its Hunters Point repowering, an option that PG&E accepts and that ER-90 invites this Commission to consider. PG&E will also solicit bids from renewable QFs to defer a small wind resource, in compliance with newly enacted Public Utilities Code Section 701.3. (AB 1090, Hayden.)

Today's decision also responds to three applications previously consolidated with Investigation (I.) 89-07-004, the Biennial Resource Plan Update. In Application (A.) 91-08-028, SDG&E has asked us to declare nondeferrable its proposed South Bay repowering. We find the project too indefinite to meet our criteria for nondeferrability, and we therefore deny the request.

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1 See Attachment 1 for explanation of each technical acronym or other abbreviation that appears in this decision.

The decision does not allocate all of SDG&E's long-term need through the bidding process, however. This means that SDG&E will have the flexibility to fill this unallocated need through whatever means it deems most advantageous to the utility, subject to later reasonableness review.

In the other two consolidated applications (A.91-02-092 and A.91-07-004), SDG&E and Edison have asked for authority to make certain capital improvements to Unit 1 of the San Onofre Nuclear Generating Station (SONGS 1). We have previously determined that these improvements are nondeferrable for purposes of the Update (Decision (D.) 91-09-073), and that SDG&E and Edison should establish memorandum accounts for recording certain SONGS 1 expenditures pending our decision on the requested authority. (D.91-12-046.)

We are now considering a proposed settlement regarding SONGS 1. The settlement could involve retiring the plant. Today's decision on capacity available for bidding precedes our final disposition of the proposed settlement. However, we will not increase the amount of capacity even if we approve retirement of SONGS 1. This Commission and the CEC will consider the impact of possible retirement in the ER-92/Update cycle.

Figures 1 through 7, following this page, summarize recommended and adopted deferrable generation additions, the timing of adopted deferrable resources, adopted set-asides for renewable bidders, and the adopted mix of overall resource additions (including demand-side management programs, spot and long-term purchases, deferrable resources, and other generation additions).

# INDEX

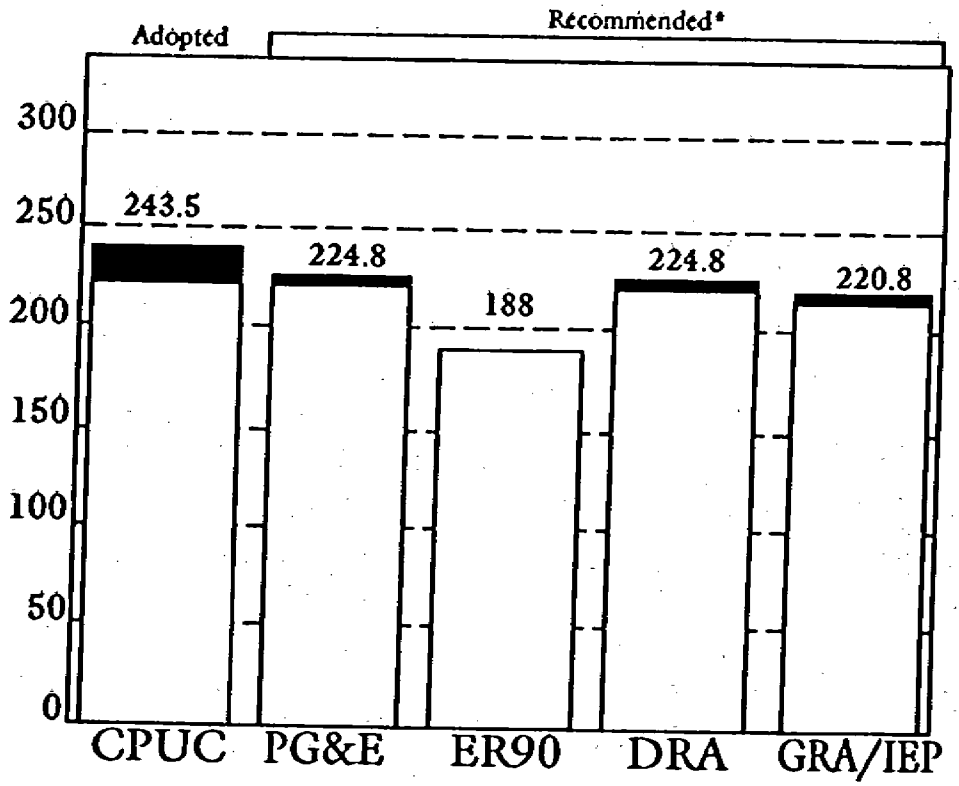
# I N D E X

# INDEX

FIGURE 1

# PG&E

## DEFERRABLE GENERATION ADDITIONS (EFFECTIVE MW 1992 - 1999)




| | CPUC | PG&E | ER90 | DRA | GRA/IEP |
|---|---|---|---|---|---|
| Wind | 22.5 | 3.8 | | 3.8 | 3.8 |
| Repower | 221 | 221 | 188 | 221 | 217 |

22.5 MW SET-ASIDE FOR RENEWABLES

Wind

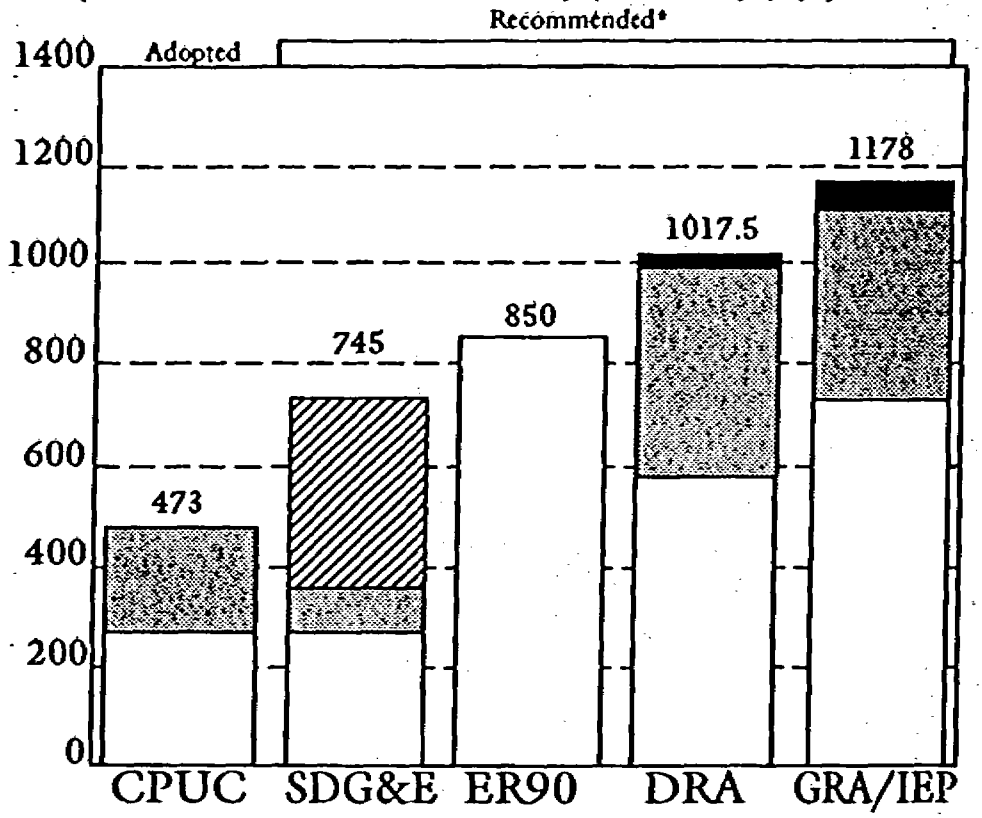
Repower

* CEERT: 460 MW TOTAL

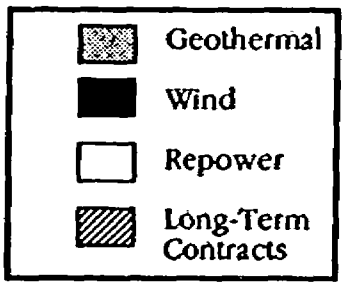
FIGURE 2

# SDG&E

## DEFERRABLE GENERATION ADDITIONS (EFFECTIVE MW 1992 - 1999)




| | CPUC | SDG&E | ER90 | DRA | GRA/IEP |
|---|---|---|---|---|---|
| Wind | | | | 22.5 | 50 |
| Long-Term Contracts | | 372 | | | |
| Geothermal | 200 | 100 | | 400 | 400 |
| Repower | 273 | 273 | 850 | 595 | 728 |
| | 100 MW SET-ASIDE FOR RENEWABLES | LIMIT BIDDING TO 50% | 460 MW SET-ASIDE FOR RENEWABLES | | |

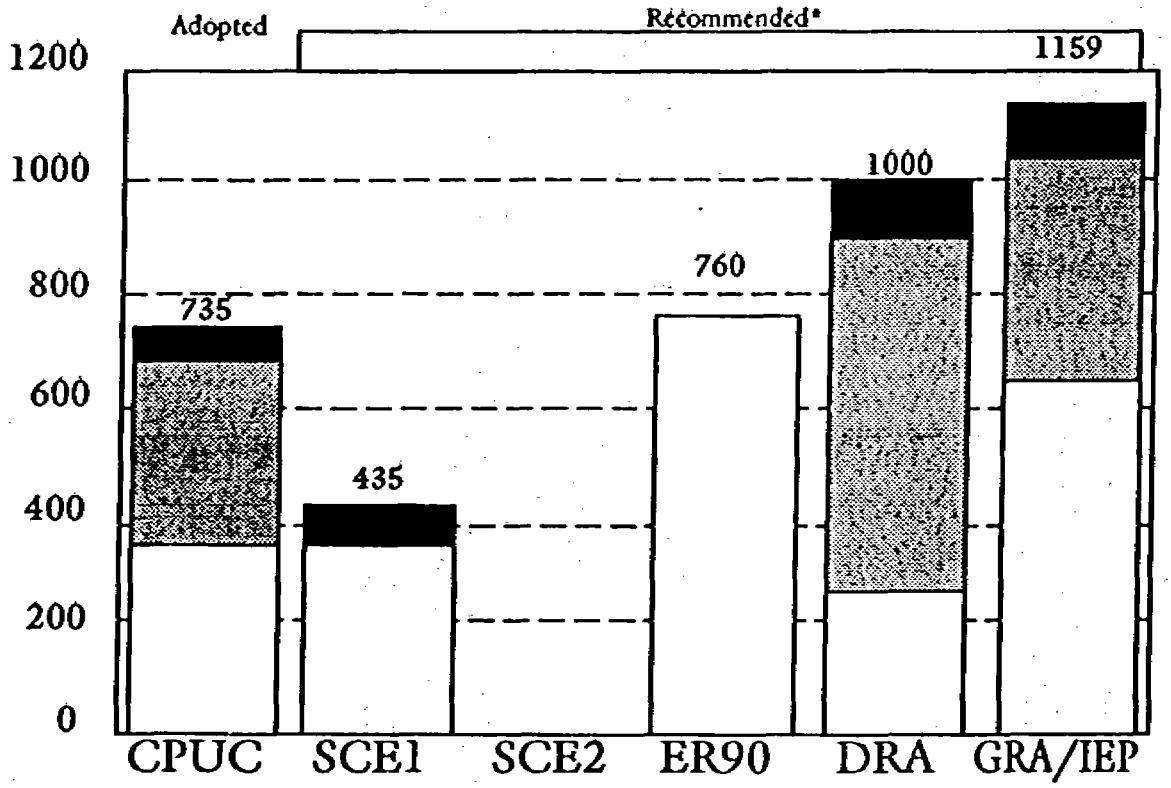



* CEERT:
100 MW WIND
500 MW GEOTHERMAL
900 MW NOT SPECIFIED

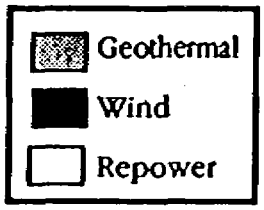
FIGURE 3

# EDISON (SCE)

## DEFERRABLE GENERATION ADDITIONS (EFFECTIVE MW 1992 - 1999)



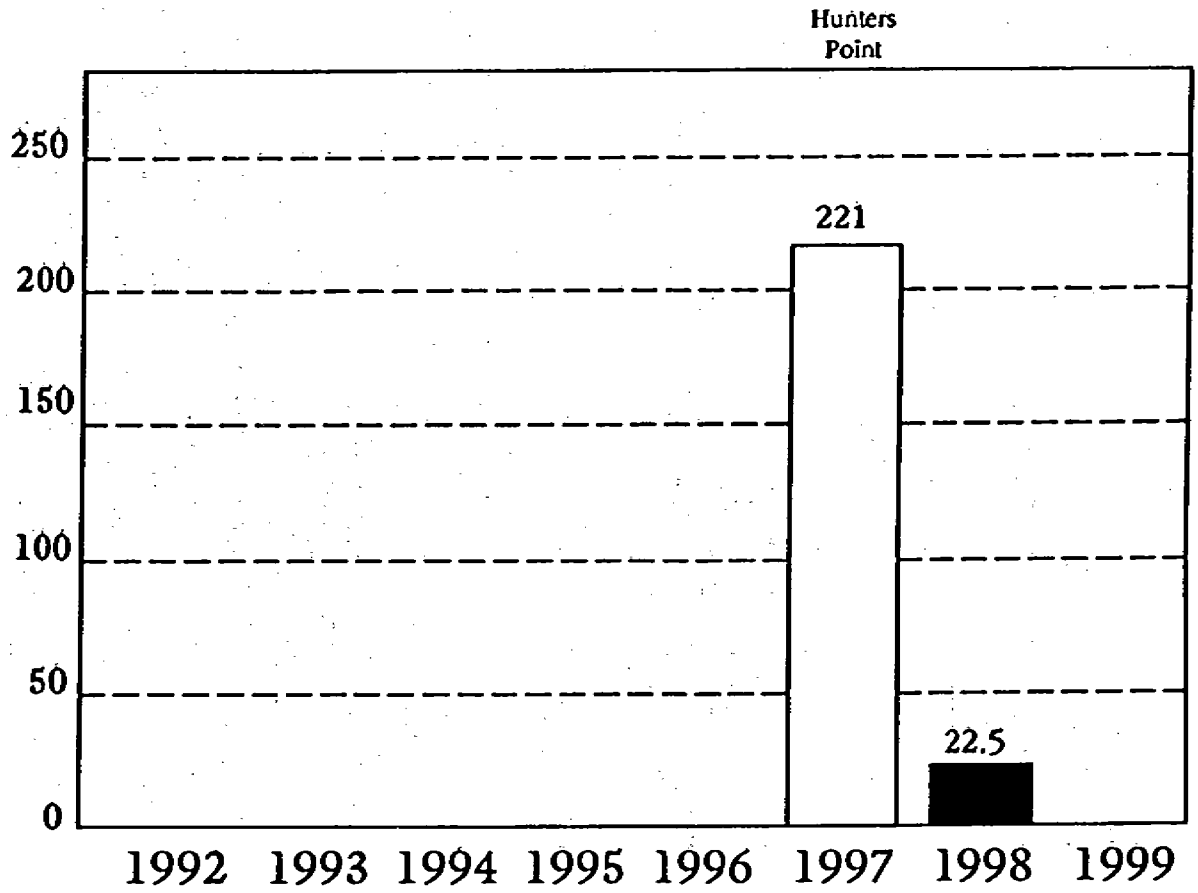

| | CPUC | SCE1 | SCE2 | ER90 | DRA | GRA/IEP |
|---|---|---|---|---|---|---|
| Wind | 50 | 50 | | | 100 | 100 |
| Geothermal | 300 | | | | 626 | 400 |
| Repower | 385 | 385 | | 760 | 274 | 659 |
| | 175 MW SET-ASIDE FOR RENEWABLES | SUGGESTED ALTERNATIVE | PREFERRED PLAN (ALL DSM) | APPROX. 50% SET-ASIDE FOR RENEWABLES | | |




* CEERT:
200 MW WIND
400 MW GEOTHERMAL
600 MW NOT SPECIFIED

FIGURE 4

# PG&E
## TIMING OF ADOPTED IDRs
## (EFFECTIVE MW 1992 - 1999)




WIND IDR SET-ASIDE FOR RENEWABLES

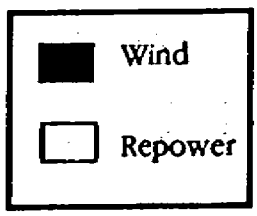
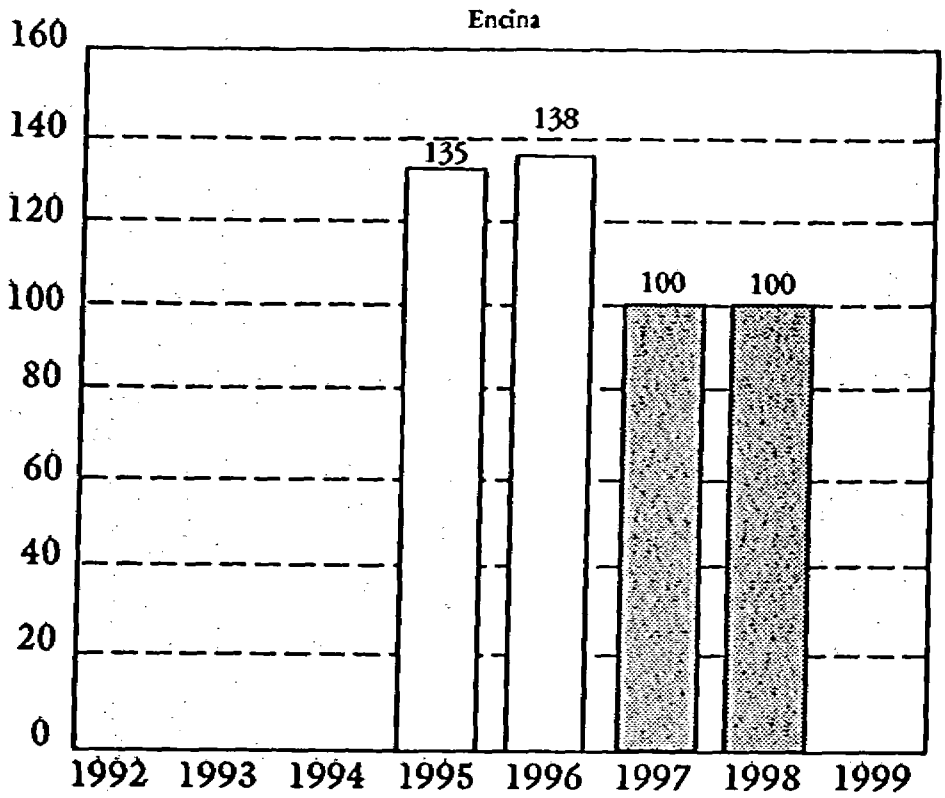


FIGURE 5

# SDG&E
## TIMING OF ADOPTED IDRs
## (EFFECTIVE MW 1992 - 1999)




50 MW OF EACH GEOTHERMAL IDR SET-ASIDE FOR RENEWABLES

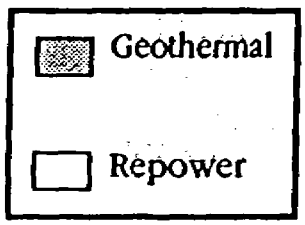
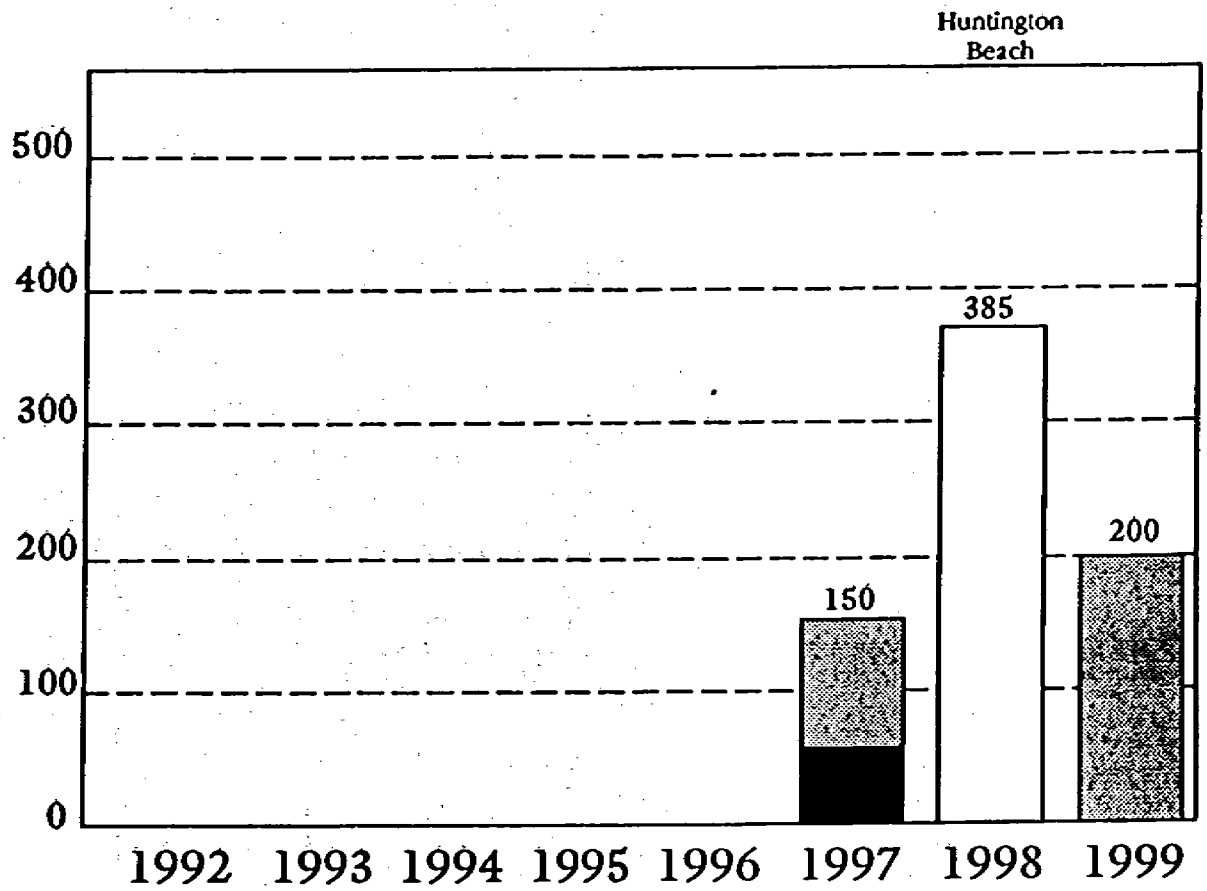


FIGURE 6

# EDISON

## TIMING OF ADOPTED IDRs (EFFECTIVE MW 1992 - 1999)



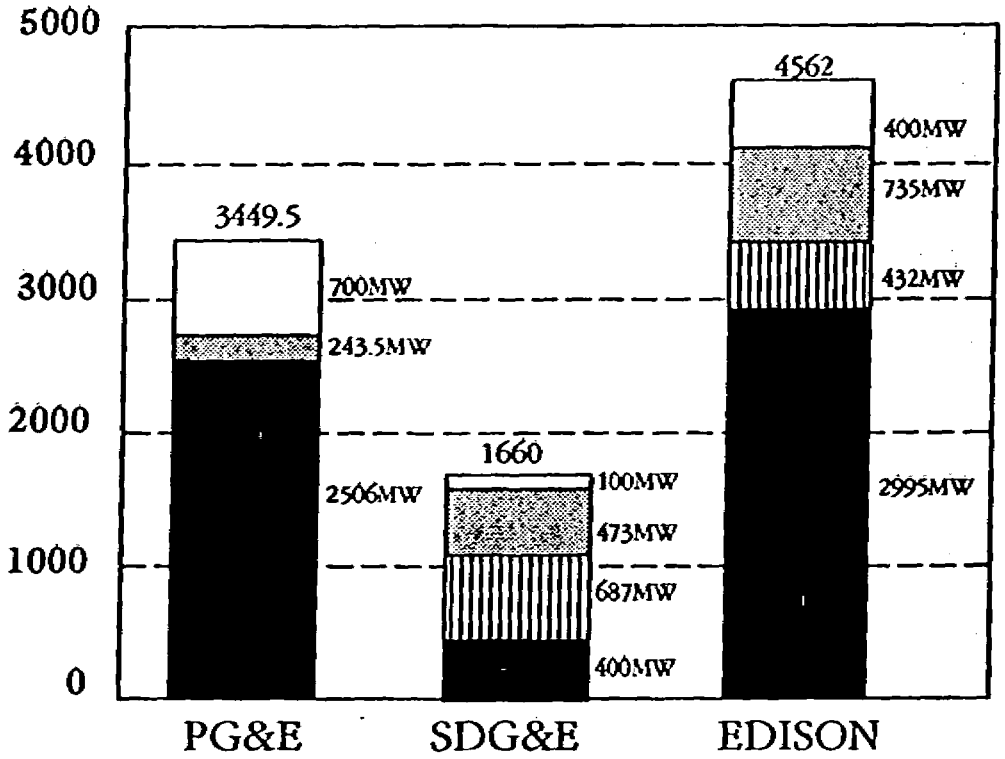

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Geothermal | | | | | | 100 | | 200 |
| Wind | | | | | | 50 | | |
| Repower | | | | | | | 385 | |

50% OF EACH GEOTHERMAL AND WIND IDR SET-ASIDE FOR RENEWABLES

Geothermal
Wind
Repower

FIGURE 7

# ADOPTED MIX OF RESOURCE ADDITIONS (MW through 1999)




| PG&E | SDG&E | EDISON |
|---|---|---|
| 7% (243.5MW) SUBJECT TO QF BIDDING | 28.5% (473MW) SUBJECT TO QF BIDDING | 16% (735 MW) SUBJECT TO QF BIDDING |
| DSM: 73% | DSM: 24.0% | DSM: 66% |
| SPOT CAP.: 20% | SPOT CAP.: 6.0% | SPOT CAP.: 9% |
| DEF. GEN.: 7% | OTHER GEN.: 41.5% | OTHER GEN.: 9% |
| | DEF. GEN.: 28.5% | DEF. GEN.: 16% |

- Spot Capacity
- Deferrable Generation
- Other Generation
- DSM

## 2. Background

### 2.1 The Role of the Biennial Resource Plan Update

Today's decision is the third major step in the current Update. The Commission created this proceeding to periodically review long-term electric resource plans and address generic issues related to utility purchases of electricity from a broad class of nonutility energy producers, called "qualifying facilities" or "QFs." Our regulation of these purchases relies on two concepts: avoided costs (as to the purchase price) and the standard offer (as to the contractual relationship).

Avoided costs represent the costs a utility would incur, if not for the presence of QFs, to generate power itself or purchase it elsewhere. The standard offer is an open utility offer to purchase electricity from a QF, on terms and conditions stated in the offer. The contract terms of the offer are developed from guidelines adopted by this Commission. Over the past ten years, we have refined and implemented these concepts in a series of decisions. (See Attachment 2.)[2]

The Update provides an industry-wide forum for continuing our regulatory oversight of utility/QF matters. A major purpose of the Update is to develop current prices for final Standard Offer 4, our resource plan-based standard offer. This involves quantifying the megawatts (MW) that QFs can fill on the basis of each utility's need for new capacity. Each two-year Update cycle commences upon issuance of the CEC's Electricity Report.

The Update is also the forum for revising certain components of QF payments that affect our short-run offers,

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2 The federal Public Utility Regulatory Policies Act (PURPA) of 1978 and the California Private Energy Producers Act (see Public Utilities Code §§ 2801-2824) supply the statutory context for the development of these concepts. The decisions listed in Attachment 2 all elucidate this legislation and these concepts.

Standard Offers 1, 2, and 3.[3] Finally, we here consider changes in methodology or contract terms for all of our standard offers.

2.2 How Final Standard Offer 4 Works

Before discussing the issues resolved in today's decision, we summarize briefly the structure created for final Standard Offer 4 in D.86-07-004. Unlike our short-run standard offers, final Standard Offer 4 derives from a utility's long-run marginal costs. These are determined from the respective utility's resource plan, which includes all cost-effective potential generation additions (e.g., new plant construction, refurbishments, power purchases, etc.).[4] Payments to QFs under the long-run offer are based on the fixed and variable costs of those additions that serve as baseload or intermediate-load resources. Such additions are called "identified deferrable resources" (IDRs).

Pricing under final Standard Offer 4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility resource addition, and the QF receives payments based on the fixed and variable costs of the avoided resource. If

3 These three offers are referred to as "short-run" because the energy price is computed on the basis of the purchasing utility's existing generation resources. In contrast to our final Standard Offer 4 "long-run" pricing approach, prices for these standard offers are calculated without consideration of possible resource additions. Attachment 3 summarizes the pricing provisions of our various standard offers.

4 QFs do not avoid or defer any resource that, as analyzed in the resource planning process, would not be cost-effective. The reason is that a prudent utility would not commit to such a resource in the first place. (See D.86-07-004, 21 CPUC 2d 340, 349 note 3 and accompanying text.) A utility may choose to pursue some kinds of generation projects that do not pass the cost-effectiveness test but serve, e.g., to demonstrate a new technology. Such projects are not part of the "resource plan" (in that they are not relied on to fill "need") and are not subject to deferral by QFs.

the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2.

The Commission considers alternative scenarios for each utility in determining a MW limit at each Update. Whenever the capacity of QFs seeking contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers. Attachment 4 presents a more detailed chronological overview of the final Standard Offer 4 updating process.

2.3 Phasing of the Issues

The Update is a phased proceeding in which general methodological issues for the standard offers are treated separately from the resource plan review to determine whether the utilities have long-term resource needs for which QFs may bid. We began this Update in response to the CEC's 1988 Electricity Report. In Phase 1A, we adopted certain planning assumptions for this Update and resolved certain generic issues over what constitutes a "committed" resource (not subject to deferral or avoidance by QFs) and how to test resources for cost-effectiveness. (D.90-03-060.)

In Phase 1B, we made certain refinements to the standard offers for implementation with any QF auction resulting from ER-90.[5] Specifically, we ensured that our QF procurement process was well-suited to all of the different electric generation

5 The 1988 Electricity Report was issued late. The Commission therefore decided to address methodological and contractual issues in Phase 1B and rescheduled the resource plan review to follow CEC adoption of ER-90.

technologies and did not have a built-in bias toward gas-fired resources. Also, we enhanced that process in order to value non-price factors, such as environmental impacts and fuel diversity, in planning and acquiring new resources. (D.91-06-022.)[6]

Today's decision comes in the resource plan phase. For each utility respondent, we designate deferrable generation resources, against whose costs and benefits QFs will bid. We also deal with utility requests for findings of nondeferrability regarding specific resources.[7]

In a nutshell, today's decision establishes (1) the respective utilities' long-run marginal costs, and (2) biddable capacity consistent with the economic and operational need tests in

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6 After the Phase 1B decision, the parties have met in workshops to develop language changes to the final Standard Offer 4 contract and bidding protocol. The changes would serve to implement the Commission's directions in that decision. We will review the results of these workshops, and hold hearings to resolve any remaining implementation issues, shortly before or after issuance of today's decision.

7 We also note two matters not dealt with in this phase of hearings but which will be important in future Updates. First is the effort to develop a common cost-effectiveness methodology for testing both DSM programs and new supply options. SDG&E applied ICEM to accomplish this in its resource planning in this phase. PG&E and Edison have not yet reached that point but have conducted "pilot" demonstrations that will undergo peer review in workshops. Our goal is that by the next Update, PG&E and Edison, like SDG&E, will perform "dynamic" cost-effectiveness testing for both supply and demand resources. Second, the assigned administrative law judges (ALJs) determined that, pursuant to D.91-06-022, the calculation of a fuel diversity premium would not be taken up in this phase. The reason for that determination was that all three utility applicants showed renewable IDRs in their base case resource plans even without including such a premium. However, the proper valuation of fuel diversity is a critical issue in resource planning, and the next Electricity Report/Update cycle should look further into quantifying this value.

ER-90. The decision also specifies a certain amount of capacity (and benchmark prices for that capacity) to be offered for possible "deferral" through QF bidding. The decision does not require, however, that only QFs fill such capacity. For example, if the auction results in "undersubscription" (insufficient QF capacity to fill the bid), then the utility may fill the remaining capacity in any reasonable way.

Today's decision also does not mandate a specific utility resource plan, nor does it award permits for a specific project. A winning bidder in the auction would still have to undergo appropriate review and obtain all relevant permits from the agencies with siting authority. Therefore, if a winning bidder is later unable to come on-line for any reason, such as its failure to obtain critical permits, the utility can fill the capacity in any reasonable way.

There is also a methodology phase to the Update. This phase, which has already begun and will run concurrently, is described more fully in Section 8.3 below.

In the following sections, we summarize the parties' positions and discuss the reasoning behind our conclusions on deferrable resources. As usual in such proceedings, the record is voluminous.[8] We concentrate on the chief points of contention, and do not try to summarize every nuance in individual positions.

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8 The record in this phase consists of 80 exhibits (including hundreds of pages of prepared testimony), 10 concurrent briefs, officially noticed items (including ER-90), and about 1,500 pages of transcript. The following parties were active in the resource plan phase: PG&E; SDG&E; Edison; the Commission's Division of Ratepayer Advocates (DRA); CEC; South Coast Air Quality Management District (South Coast AQMD); San Diego Air Pollution Control District (San Diego APCD); Coalition for Energy Efficiency and Renewable Technologies (CEERT); Geothermal Resources Association and Independent Energy Producers Association (GRA/IEP); Southern California Gas Company (SoCalGas); U.S. Windpower; ERC Environmental and Energy Services Company, Inc. (ERCE); Utility Workers Union of America; and San Diego County Building & Construction Trades Council.

3. Policy Direction: Electric Resources and Air Quality

Today's decision is the culmination of the resource plan phase of this Update. One of the key issues in this phase is the effect on planning strategies of explicitly valuing the costs that residual air emissions from power plants impose on the environment. Explicit recognition of these costs enables a fair assessment of electric resource options with little or no residual air emissions. Accounting for these costs may have an effect on the cost-effectiveness of the various resource options available to meet the state's electricity requirements.

While much of the public debate surrounding this phase of the Update has focused on the issue of residual emissions, we reaffirm that this Commission must and will continue to balance many electric resource planning objectives along with environmental quality. Equally important are traditional objectives such as reasonable rates and reliable service for all ratepayers. In meeting these objectives, California utilities now face the additional challenge of planning for and acquiring a clean mix of energy resources for the future.

Concern for air quality is not new for energy planners in California. Both this Commission and the CEC have long supported a greater role for energy efficiency and for cleaner technologies in meeting electricity needs. California utilities have generally led the nation in their conservation programs and in developing generation technologies that rely on renewable or alternative fuels. In the past 12 years, California industry and utilities have developed thousands of MW of cogeneration, which reduces air emissions by increasing useful output per unit of fuel consumption.

Despite the success of the utility and other sectors of the California economy in preventing further environmental degradation, these efforts did not achieve the significant

improvements in air quality necessary to satisfy state and federal clean air standards. Meeting those standards will require a wide variety of actions, including more stringent emission limits, implementation of more costly control technology, and retrofit of existing facilities.[9]

Air quality regulators such as the South Coast AQMD (which is charged with bringing the Los Angeles basin into compliance with air quality standards) have developed a variety of programs and measures from which the costs of clean-up can be calculated.[10] Both the CEC and this Commission have determined that such costs should be factored into the process by which electric utilities plan for resource additions. The effect of this determination is to assign for the first time a monetary value to the residual emissions[11] of power plants. In other words, the clean air value of less-polluting plants is now expressed in dollars and cents.

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9 D.91-06-022 contains a summary of air quality information useful for understanding how air quality affects electric resource planning. Rather than burden the text, we reproduce this summary (Sections IV.B and IV.C of D.91-06-022) as Attachment 5 to today's decision.

10 The Los Angeles basin has the most severe air quality problems in the nation, but both San Diego and the San Francisco Bay Area are also non-attainment areas for various pollutants. The San Diego APCD's proposed rules appear at least as stringent as the South Coast AQMD's adopted rules. Because less is known about clean-up costs in the Bay Area, the Commission adopted lower air emission values for use by PG&E. These values are not analytically rigorous but reflect the qualitative judgment that Northern California in general has less severe air quality problems than does Southern California.

11 "Residual emissions" are air pollutants that are released after all mandatory pollution abatement measures have been implemented.

We note that California's existing energy services infrastructure was developed without such explicit valuation of these environmental costs. This situation has complicated current efforts to achieve compliance with ambient air quality standards throughout the state.

Our efforts today are a step to revitalizing California's energy infrastructure by accounting for the true total costs and benefits of providing electric service. We want to avoid the burden of this revitalization falling disproportionately on ratepayers. Our measured actions are designed with the recognition that the utility sector of our economy is only one contributor (and not the largest contributor) to the state's air quality problems.

We will face increased costs to acquire the emissions reductions associated with this additional objective, simply because some of the cleanest resources have higher capital costs than many other resources. We fully recognize both the costs and benefits of this additional objective, which is another way of saying that our process enables us to strike a balance between those costs and benefits. We will not pursue our environmental objectives without regard to cost.

To help us strike the proper balance, the utilities incorporated residual emission values in their ICEM analyses. This computer modeling is a diagnostic tool; using the results of such modeling in various ways, the parties have applied uncertainty analysis and their own strategic preferences to develop proposed solutions, i.e., their preferred resource plans.

This quantitative and qualitative analysis confirms that PG&E, SDG&E, and Edison all need additional resources over the next eight years (the IDR "window" for purposes of the Update). This is consistent with the CEC's conclusions in ER-90.

### 3.1 How Emissions Valuation and Fuel Diversity Affect this Decision

Placing a (negative) value on residual emissions and a (positive) value on generation resources that increase the fuel diversity of our resource mix has two potential impacts of great concern to electricity planners. First, internalizing air quality impacts in the ICEM analysis justifies on strict economic grounds increased investment in resources with low or no emissions.[12] Second, the environmentally sensitive least-cost plan produces more benefits (better air quality) but may cost more (because the resources with low or no emissions generally have high capital costs) than the traditional least-cost plan.

These concerns are easily handled. First, as we have consistently held beginning with D.86-07-004, we will not exceed the CEC's "integrated assessment of need" in its current Electricity Report. We keep that commitment here, and in one case (SDG&E), we even stop well short of the total MW found needed in ER-90.[13] Second, the IDRs we designate include a mix of gas-fired resources (repowers) with wind and geothermal resources. The repowers are highly cost-effective with or without consideration of residual emissions, and for each utility the repower IDRs make up a majority of the capacity offered in this solicitation. These IDRs

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12 At this time, we do not have an explicit value for fuel diversity, since residual emission valuation by itself was sufficient to cause diverse technologies to appear in the base case resource plans. We believe, however, that fuel diversity has benefits distinct from air quality and should be valued separately. We urge the CEC to continue its analysis of this question in ER-92. Meanwhile, fuel diversity has its own role in this Update through our implementation of the statutory set-aside for renewable technologies. (See Section 3.1.1 below.)

13 For explanation of our decision to limit SDG&E's solicitation, see Sections 3.4 et seq. (on strategic preferences) and Section 5.1 below.

(or QFs that underbid them) will significantly enhance the fuel diversity and emissions performance of the currently fossil fuel-dominated Edison and SDG&E systems and at the same time will produce lower rates on those systems compared to the rates resulting from Edison and SDG&E continuing to run their existing power plants.

SDG&E has clearly grasped these principles and, in its preferred resource plan, reaches results similar to today's decision.[14] Edison has more difficulty due to its failure to reflect within its own planning the cumulative impact of our resource planning decisions of the past 12 years.

One policy that seems to baffle Edison is our policy in D.91-06-022 that residual emissions be valued; another is our policy (going back to D.86-07-004) that cost-effective resources be added to the resource plan in the first year of cost-effectiveness, regardless of "real world" construction lead-times.[15] When rolled into Edison's and SDG&E's analyses, these policies contribute to a finding that both Edison and SDG&E need to change their resource mix substantially to reduce emissions.

Edison portrays this finding as "unintended."[16] On the contrary, we fully intend to understand the effect of residual emissions valuation. Where that effect is significant, we fully intend to hear from the parties, including the utilities, on how

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14 PG&E also reaches results similar to today's decision, although that is not surprising since the range of planning outcomes is much narrower for PG&E than for SDG&E.

15 The construction lead-time policy is further discussed in Section 3.4.4 below.

16 The finding could hardly come as a surprise. Edison has thousands of MW of aging gas-fired generation in the Los Angeles basin, which has the most severe air quality problems in the United States.

best to reduce environmental costs, with due consideration for ratepayers' out-of-pocket costs and our other planning objectives. Rather than suppress or ignore such information, we think the only way to balance objectives properly is to inform ourselves as fully as possible of the factors that influence the relative weight to be accorded competing objectives at a given time.

Neither emission valuation nor "ideal" resource timing interferes with our ability to balance different planning objectives; they are necessary inputs to the balancing process. They help define the range of potential air quality benefits. We then develop, through balancing, the best practicable plans that include environmental sensitivity.

One significant change adopted in today's decision that should assist the balancing process is our shift in residual emissions valuation from uniform to nonuniform values. (See Section 9.2 below.) Also, we agree with SDG&E and PG&E that a distinction must be made between long-term and short-term resources (see Section 3.4.1 below), and we also conclude that the addition of residual emissions valuation to ICEM precludes reliance on a single ICEM scenario for resource planning purposes.[17] These scenarios are presently too skewed by the air quality factor to allow us the flexibility we need to balance the various planning objectives. Over time, the utility systems should reduce their emissions and air quality-driven need will decline, which will in turn avoid the kind of lumpy first-year additions that concerned Edison in this Update.

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17 In D.86-07-004, we contemplated specifying one of the ICEM scenarios to derive the IDRs. Virtually all the parties in the current Update depart to some extent from strict scenario reliance, and they were correct to do so.

### 3.1.1 Impact of New Legislation

The previous phase of this proceeding included the issue of whether this Commission should ensure that QFs using renewable fuels fill at least a stated portion of electric resource need. In D.91-06-022, we declined to make such an a priori allocation to renewables. We preferred a process that would allow all technologies to bid against all IDRs but would include in planning and in bidding specific dollar values for the air quality and fuel diversity benefits that renewable resources provide.[18]

After that decision, Governor Wilson signed two bills strengthening California's commitment to renewable resource development. AB 2198 (Sher) adds Section 701.4 to the Public Utilities (PU) Code:

> "It is the policy of the state and the intent of the Legislature that state and municipal electric resource acquisition programs recognize and include a value for the resource diversity provided by renewable resources."

This statute essentially codifies the fuel diversity policy that we approved in principle in D.91-06-022.

Also, AB 1090 (Hayden) adds PU Code Section 701.3:

> "Until the [CPUC] completes an electric generation procurement methodology that values the environmental and diversity costs and benefits associated with various generation technologies, the [CPUC] shall direct that a specific portion of future electrical generating capacity needed for California be reserved or set aside for renewable resources."

These statutes take effect on January 1, 1992, and we conclude that they govern resource procurement in this Update. Our methodology does not yet quantify the value of fuel diversity, however, so the

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18 See generally D.91-06-022, mimeo. pp. 13-14, 26-39. However, neither ER-90 nor D.91-06-022 adopts a value for fuel diversity.

provisions of Section 701.3 require us to "set aside" a portion of generating capacity for renewable resources in the coming bid solicitation. Our record contains ample basis for implementing these provisions.

We will adopt for purposes of the renewables set-aside the definition of non-fossil resources that we used in D.91-06-022, i.e., generation resources that do not use oil, coal, or natural gas as their primary fuel source. Qualifying projects would include wind, hydro, geothermal, solid waste, biomass, and solar projects. Such a project must not use any amount of oil or coal, but may use natural gas for no more than 25% of its total energy input during a calendar year. A project acquired through the set-aside must certify compliance with these fuel use restrictions as part of its commitments under its final Standard Offer 4 contract.

We will structure the set-aside keeping in mind our goal of substantial consistency with ER-90's integrated assessment of need. Thus, each utility will have a set-aside tailored to its total resource need and the diversity, or lack of diversity, of its current resource mix. The specifics are described in later sections of today's decision.

Some of the aspects of bidding on set-asides are the subject of a proposal set forth in Attachment 6 to today's decision. The parties will have an opportunity for further comment on how these aspects should be resolved. (See also Section 8.2 below.) However, the following rules are adopted now for administering the set-aside capacity solicitation in this Update. First, each set-aside will have benchmark prices set by a renewable IDR. Second, all technologies will be allowed to bid against renewable IDRs, but at least half the capacity of each renewable IDR will be awarded to renewable bidders (assuming there are sufficient renewable QF bidders to fully subscribe the

set-aside).[19] Third, second-price auction rules apply to the price awarded the winning bidders. (But see Attachment 6 on the issue of whether the second-price should be determined separately for the set-aside and all-technology winners.)

3.1.2 California's Fuel-Neutral Resource Strategy

Recognizing the environmental costs of residual emissions of different generation resource options affects cost-effectiveness analysis for purposes of resource procurement. Our policy applies to all resource types and all fuel sources. Because coal-burning technologies can produce more emissions than do many other generation technologies, the relative cost-effectiveness of coal generally declines.[20] This is a predictable result of the application of our analytical tools.

However, as we noted earlier, meeting the state's objective of minimizing the environmental costs of providing electricity service is one of several important objectives we must balance. In the balancing process, we cannot ignore the CEC's conclusion that new coal-fired plants should have no role in

19 PG&E's wind IDR is an exception to this rule. Since it is a small IDR in absolute terms and also in comparison to PG&E's repower IDR, bidding on this wind IDR is limited to renewable QFs.

20 This generalization requires some qualification. For example, some fuel oil has a high sulfur content, with resulting higher emissions of sulfur/oxygen compounds (SOx), while some coal has a low sulfur content. The emissions from any power plant also depend on the pollution abatement equipment at the plant, the way the plant is run, and many other parameters besides fuel type. There are also technologies (existing or under development) to treat or convert coal to permit cleaner combustion. Our method for valuing residual emissions captures such variation, however, because the air quality cost is based on plant-specific emission rates, and is not a generic cost based on fuel type.

California utilities' resource plans at this time.[21] The CEC's recently-adopted report on global climate change[22] brings a coal-based strategy further into question in its recommendation (at page 22 of the report) that California reconsider altogether any contribution from coal-fired resources. Given the valuable role that coal and other fossil fuel generation technologies have traditionally played in helping California meet its energy requirements, we believe a more measured approach is appropriate.

3.1.2.1 Purchases from Fossil-fired Power Plants

Consistency is an essential element of an effective energy policy. Today's decision and D.91-06-022 signal a change; however, they do not make radical departures but rather continue our development of competitive resource procurement that we began more than a decade ago. While this development is still evolving, its underlying direction toward a "level playing field" for all suppliers of electricity should guide the way our regulated utilities plan for and develop their energy resource infrastructures.

Accordingly, today's decision sends two important messages. First, consistent with our statutory mandate, we are committed to recognizing all significant costs--including environmental costs--in choosing the long-term mix of resources

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21 "The Commission [CEC] does not find a role for new coal-fired power plants." (ER-90 at p. 6-2.) The CEC reached the same conclusion in its 1988 Electricity Report, even though it there ascribed no cost to residual emissions. We interpret the quoted statement to mean that the full social and private cost of building, owning, and operating a coal-fired facility at this time significantly exceeds the costs of other resource options now available to California's electric utilities. The utility resource plan showings in the Update certainly support such a conclusion.

22 "Global Climate Change Report: Potential Impacts and Policy Recommendation" (adopted November 20, 1991).

that will meet California's electricity requirements. Second, and equally important, we provide energy suppliers with the price signals necessary to help them plan for and participate in California's electricity market.

We recognize that state policy to directly incorporate environmental costs is a change. In some instances, the relative cost-effectiveness of proposed purchases from fossil-fired resources, and in particular, from existing coal plants, turns on these costs. In considering these proposed purchases, we make a crucial distinction between long-term and short-term purchases.[23]

As part of our overall strategy to manage the transition to a more environmentally sensitive resource planning framework, we will judge the cost-effectiveness of short-term purchases on a private least-cost basis, i.e., without consideration of residual emissions. (For a complete discussion, see Section 3.4.1 below.) This policy is part of our commitment to consistency and to balance, maintaining relations with California's traditional supply sources while achieving a diverse and steadily cleaner generation mix.

Long-term purchases from existing fossil-fired plants present more difficult policy questions, however. Choices for long-term resources go to the heart of this planning process. These choices are ones that ratepayers will live with for 20 years, 30 years, perhaps longer. Failing to include environmental

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23 The public discourse on the Update causes us to make explicit another distinction. The Update concerns planning for future resources. It does not concern the utilities' dispatch of resources already on their systems. We have not required utilities to factor residual emissions into their daily dispatch decisions (so-called "environmental dispatch"), nor does the Update affect economy energy transactions. We are aware that other states may be considering environmental dispatch, and we will monitor their deliberations, but we do not have plans to take up that subject.

objectives in our choices for the long-term would prevent us from achieving our goal of environmentally sensitive, least-cost electricity service.

One argument for special treatment of long-term purchases from existing coal plants is that they are all outside California and therefore, by implication, they do not affect California air quality. The implication is inaccurate in material respects. Coal plants generally emit large quantities of carbon and SOX. These pollutants raise concerns about potential impacts, e.g., climate change and acid rain, that cross state and even national boundaries.[24]

Furthermore, the extent of the climate change problem and national policy on climate change remain uncertain at this time. We agree with the CEC that it is currently prudent to ascribe a fairly low value to carbon emissions; nevertheless, it is also prudent to adopt resource procurement policies recognizing that owners of existing coal-fired generation in the future may be required to take actions to abate their carbon emissions significantly, or to pay for emission rights. This raises the concern that the owners may try to pass on the costs for such actions to their customers, including other utilities making wholesale purchases.

We conclude that the Update long-term procurement process should contain no special exclusions for particular generation

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24 The federal Clean Air Act Amendments of 1990 create a nationwide program of tradeable sulfur dioxide (SO2) emission permits. The idea behind nationwide trading of such permits is that abatement of SO2 emissions in one region of the country does improve the environment in other, distant regions. The CEC applies similar reasoning to its treatment of carbon emissions, i.e., it values such emissions uniformly regardless of where they occur: "As air districts have recognized, local decisions can have global impacts. Those global impacts must be evaluated." (ER-90 at p. 5-14.)

technologies, generation sites, or pollutants. The same procedures, including valuation of emissions, ought to apply to all technologies and to all plants, whether existing at the time of the Update or to be constructed. This conclusion follows directly from our commitment to a "level playing field" for competing sources of supply.

Utilities, however, are authorized to make resource acquisitions outside the Update process using their best judgment and subject to reasonableness review. This does not mean the utilities may or should ignore residual emissions valuation between Updates when considering long-term purchases from fossil-fired resources. The concerns expressed above would continue to have force in a reasonableness review. Utilities are authorized to vary from assumptions used in the Update, but only to the extent such variation is acknowledged and justified to our satisfaction.

Given the uncertainty over policy addressing climate change, we also believe it essential that utilities obtain appropriate assurances from any prospective supplier with significant carbon emissions. Such a supplier must expressly assume the risks relating to this uncertainty. Specifically, PG&E, SDG&E, or Edison should undertake a long-term purchase only if the supplier provides assurance that it alone will bear the cost of meeting any future costs resulting from a carbon tax, acquisition of tradeable emission permits, retrofits, or any other carbon

emission control strategy or regulation applicable to the supplier's plant(s).[25]

3.1.3 How Offsets Affect This Decision

The parties raised various issues regarding offsets and their application to repower projects. There is also a methodological dispute. We address each of these issues below.

3.1.3.1 Offset Costs of a Repower Project

Parties raised two issues regarding the utilities' treatment of offset costs in connection with repower projects. The first issue is whether the cost of the repower project should include the value of the exemption from offset requirements for the capacity of the original unit. When a utility builds a repower project, the utility needs offsets only for the incremental capacity (i.e., the total capacity of the repower minus the capacity of the original boiler taken out of service). SDG&E, for example, imputes no value to this regulatory exemption in calculating the cost-effectiveness of repowering its plants.

The second issue is similar: Should a utility impute value to an offset it obtains by shutting down one of its other plants and applying the offset to the incremental capacity of its repower? An example of this issue is Edison's analysis of the cost-effectiveness of the San Bernardino repower. Edison would apply an offset obtained from the retirement of another plant to the San Bernardino repower, but would not treat that offset as a cost of the project.

We have previously decided that the value of required offsets should be recognized as costs in the cost-effectiveness

25 Essentially, any QF under any of our standard offers bears such risks with respect to all air emissions over the life of its contract. Thus, the assurance described in the text does not impose an unusual or punitive burden on non-QF sellers. We also understand that the Bonneville Power Administration is seeking similar assurance from its potential suppliers.

analysis of a candidate IDR. (See D.91-06-022, mimeo. p. 14.) Offsets already owned and exemptions from offset requirements are both assets that may be consumed in a repower project and thus have a value equal to the cost of a corresponding amount of offsets acquired in the open market. Therefore, these costs should be included in determining the costs of the repower project.

SDG&E argues with respect to the first issue that the exemption is a direct benefit of the repower and would not exist absent a repower. We disagree. The utility could shut down a boiler for the benefit of a project at a different site or for a repower at the boiler's existing site. However the shut-down is classified, it is the equivalent of an offset acquired from a third party and the utility is consuming it in the process of developing new generation. Thus, we agree with the parties arguing that there is an opportunity cost in the shut-down that must be reflected in cost-effectiveness analysis and the IDR benchmark.

There are several instances in this phase where a utility did not include the value of offsets and exemptions in a manner consistent with this discussion. We will not require new cost-effectiveness analyses in these instances; the repowers appear highly cost-effective regardless.[26] Where we designate repowers as IDRs, however, the utility must correct the IDR's capital costs to include the full cost of offsets, as indicated above.

3.1.3.2 Residual Emissions of a Repower Project

Another issue concerns how to calculate the residual emissions of a repower, considering the interaction of offsets and

26 We recognize that ER-90 also found many repowers to be cost-effective.

exemptions from offset requirements.[27] In the Update, we follow air district rules in calculating residual emissions. South Coast AQMD disagrees with the utilities' calculation of residual emissions for repowered capacity that is exempt.

According to South Coast AQMD, an exemption from needing to obtain an offset is not equivalent to an offset for purposes of calculating residual emissions. South Coast AQMD believes the utilities err when they apply "imaginary" offsets to the emissions from the exempt capacity, effectively setting the net emissions from that capacity at some negative number. South Coast AQMD argues only the emission offsets and offset ratios associated with the incremental capacity should be netted against the total repower emissions.

We agree with South Coast AQMD. When the residual emission calculation is performed correctly, most repowers will have net residual emissions for the total repowered capacity, roughly equal to the actual plant emissions minus the offsets acquired for the incremental capacity.[28]

We note that the effect of this improper treatment of emissions from exempt capacity is to improve the cost-effectiveness of repowers by reducing the imputed emissions costs. However, for the reasons stated in the preceding section, we will not require

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27 A repowering is basically a new power plant utilizing an existing site and some components of an existing plant. The repowered plant's emissions will probably differ from those of the existing plant that it replaces, so the repower's residual emissions, like those of any other long-term resource option, must be included in cost-effectiveness analysis.

28 It is possible, however, for a repower to have net negative emissions when the incremental capacity and the offset ratio are large enough. For example, if an existing 100 MW plant is repowered to 600 MW and the offset ratio is 1.3:1, the offsets for the increment could exceed the emissions rate of the total repowered capacity.

the utilities to re-do their cost-effectiveness analyses. We expect the utilities to correctly calculate repower emissions in the next Update. We also expect the utilities to make this correction for this Update in their published bid solicitations based on repower IDRs.

Finally, we invite the air districts to continue to provide their valuable input to the Update, as South Coast AQMD and San Diego APCD have in this phase. We will continue to refine our procedures to coordinate with and to complement actions of the California air quality regulators. (See D.91-06-022, mimeo. p. 40.)

3.1.3.3 Offset Cost Calculation

Calculating the cost of an offset is another significant issue. There are methodological differences between the parties, although these differences do not materially affect the finding of resource need.

DRA and the utilities both value offsets at the marginal cost of emission control for the various criteria pollutants (see Attachment 5) for the respective utilities. DRA and the utilities differ on the time period for which the offset value is calculated.

The offset calculation for nitrogen/oxygen compounds (NOx) is the one all parties concentrate on because NOx is generally the most significant criteria pollutant in California. DRA starts with a levelized (or annualized) number based on the cost of NOx emission control equipment having a ten-year life. DRA calculates the net present value of the ten-year payment stream, multiplies it by factors which represent the amount of offsets required, and then considers the resulting number a one-time capital cost. This cost would be used in ICEM in the same way as other capital costs.

Although the approaches of the three utilities differ, each essentially views the NOx offset value as an annualized number which applies to all years of an IDR's operation (as opposed to the 10 years used by DRA). Edison and SDG&E calculate a one-time offset cost, and PG&E calculates annual offset costs.

We find that DRA's method for calculating offset costs is correct. Calculating the one-time offset purchase price based on the net present value of a 10-year amortization appropriately applies the South Coast AQMD's marginal cost methodology. In contrast, the utilities' methods overstate offset costs and inflate the bidding benchmark for repower IDRs. The utilities should correct their IDRs' capital costs accordingly.

Even DRA's method yields offset prices higher than those found currently. Those prices may be expected to rise rapidly, however, as demand for offsets increases.[29] Furthermore, the CEC anticipates that offset prices could reach levels consistent with DRA's calculation. (See ER-90 at p. 5-8.) We are satisfied with the DRA method for this Update.

### 3.2 How DSM Affects This Decision

#### 3.2.1 Fully Integrated Resource Planning

After recognizing air quality impacts in our planning goals for electric utilities, probably the single most important resource planning task facing this Commission and the CEC is improving our capability to evaluate DSM and to directly compare DSM resources with supply-side resources.

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29 ER-90 (in Appendix E, p. E-54) notes that NOx offset costs in the South Coast AQMD ranged from $4,100 to $13,500 per ton/year one-time cost, and that these costs have risen rapidly. GRA/IEP panelist Branchcomb reported at the en banc hearing that PG&E has reached agreement to sell NOx offsets to the Sacramento Municipal Utility District for a one-time cost of $28,000 per ton/year. (RT 5257.)

Until recently, both this Commission and the CEC used ICEM to test the cost-effectiveness of generation resource options and the Standard Practice Manual to test the cost-effectiveness of DSM options.[30] The use of different planning tools makes it difficult to ensure that the final resource plans result in an optimal mix of generation and DSM. With our renewed emphasis on DSM, this difficulty becomes a major concern.[31] We also believe there is substance to GRA/IEP's claim that current procedures in the ER/Update cycle create a de facto set-aside for DSM.

SDG&E is the leader in addressing this concern, i.e., the need to fully integrate supply- and demand-side planning. In the current Update, SDG&E performed a pilot analysis adapting ICEM to evaluate both generation and DSM resource options. After peer review and workshops, SDG&E modified its pilot analysis and incorporated the results in its resource plan testimony in this phase.

Meanwhile, PG&E and Edison are doing their own pilot analyses. DSM resources differ from generation resources in many ways, and PG&E and Edison have larger loads and less homogeneous service areas than does SDG&E. Thus, the two larger utilities

30 The full title of the current version of the Manual is Standard Practice Manual for the Economic Analysis of Demand-Side Management Programs. The Manual is a joint product of the two commissions, in consultation with energy utilities and other interested parties.

31 The Manual is well-adapted to analyze the characteristics of DSM resource options, but the Manual uses a "static" test of cost-effectiveness. ICEM is a "dynamic" test, i.e., it recognizes that marginal costs decline with each resource found cost-effective and added to the resource plan. ICEM's "dynamic" character makes it superior to the Manual, at least with respect to determining the size and timing of resource additions. Relying entirely on the Manual might be inconsistent with least-cost planning, i.e., might result in over-reliance on DSM. See our critique of Edison's all-conservation resource plan (Section 6.1 below).

cannot necessarily adapt ICEM in the same ways that SDG&E did. We will again use peer review and workshops to assist their progress. We hope that PG&E and Edison will each have an "integrated planning method" for analyzing the cost-effectiveness of supply- and demand-side resource options in the next Update cycle.

SDG&E's progress gives us confidence that SDG&E has a reasonable level of "uncommitted" DSM in its resource plan.[32] The CEC in ER-90 expressed dissatisfaction with the level of uncommitted DSM for SDG&E and indicated it would accept a higher level if sustained in the Update. (Id. at p. 6-21.) SDG&E here shows about twice the ER-90 level of uncommitted DSM, amounting to about 30% of SDG&E's resource need over the next eight years. The parties agree, subject to some general reservations about DSM forecasting discussed in the following section, that SDG&E's levels of uncommitted DSM are reasonable.

We applaud SDG&E's leadership and also the efforts of PG&E and Edison in this area. We caution, however, that the resource plan phase of the Update is too compressed a review for us to say that SDG&E's "integrated planning method" is now perfected. These adaptations of ICEM are new, and SDG&E made several revisions to its estimates during this phase, which suggests the possibility of further modification to improve accuracy or ease of use. We also hope that the CEC in ER-92 will continue this effort, since our agreeing on appropriate levels of DSM is important to both commissions. Thus, we anticipate much activity in workshops here and during ER-92 to further refine our integrated planning methods.

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32 Uncommitted DSM consists of utility DSM programs that are cost-effective but not yet authorized. ER-90 refers to them as "programs not currently in place but which should receive regulatory approval during the forecast period." (Id. at p. 4-12.)

3.2.2 Reliance on DSM Programs

We alluded in the previous section to our renewed emphasis on DSM. The electric utilities also have strong new incentives to pursue DSM programs because of earnings opportunities created by our adoption of incentive mechanisms proposed in the California Colloborative. Moreover, the CEC has projected that DSM programs should fill about 70% of statewide resource needs (ER-90 at p. 6-2), with an even higher level for PG&E and a slightly lower level for Edison. (Id. at pp. 6-3, 6-10.) Some parties now suggest that this degree of reliance on DSM programs may be unduly optimistic.

Specifically, DRA proposes several generic adjustments to various components of the utilities' forecasts. (See Exhibit 353, pp. 4-14, 4-15.) GRA/IEP go further. Their testimony argues that, currently, "the largest uncertainty in the resource plans [is] the level of uncommitted [DSM] assumed." (Exhibit 381, p. 7.) GRA/IEP witness House criticizes the current planning process, particularly the incomplete integration of resource planning that we discussed in the preceding section. He also cites evidence that DSM savings are often overstated and may not persist. (See generally id., chapter 3.) He recommends that we "discount the uncommitted DSM levels of ER-90 by 50% to adjust for uncertainties about whether the energy savings predicted will actually be realized." (Id., p. 26.) According to House, this adjustment would result in about the same levels of uncommitted DSM as those the CEC adopted in the 1988 Electricity Report.

We do not make the requested adjustments to the utilities' DSM forecasts, but we share many of the concerns expressed by DRA and GRA/IEP. Successful conclusion of the integrated planning exercise described in the preceding section would moot some of these concerns in future Updates. Also, we will address both the measurement and evaluation issues raised by GRA/IEP and DRA, and the issues raised by DRA witness Schultz about coordination between different CPUC proceedings, in our

consolidated DSM rulemaking and investigation. (R.91-08-003 and I.91-08-002.)

We also agree with GRA/IEP witness House that, given the large amount of DSM in current utility resource plans, it is legitimate to consider the uncertainty of DSM forecasts, especially if evidence shows that the confidence levels for these forecasts are lower than for other key planning assumptions. Conversely, uncertainty analysis could include CEERT's suggestion to create a scenario utilizing DSM and renewable resources exclusively.

3.2.3 DSM Bidding Pilots

In a separate DSM Rulemaking/Investigation (R.91-08-003/I.91-08-002), we are testing various forms of DSM bidding pursuant to PU Code § 747 and our recently adopted rules governing DSM.[33] PU Code § 747 requires that one or more energy utilities implement pilot programs to test: (1) the ability of DSM bidding to deliver benefits to utility customers, separate from any generation resource bidding system; (2) the feasibility of an integrated bidding system that includes both generation resources and DSM programs; and (3) a program of competitive DSM bidding auctions for gas utilities. We have recently approved a DSM-only bidding pilot for PG&E, and additional pilots will be submitted for our consideration this year. (See D.92-03-028.)

On February 24, 1992, Transphase Systems, Inc. (Transphase) filed motions to intervene in the Update and to consolidate integrated bidding with this proceeding. Transphase requests that third-party providers of DSM services be allowed to bid, along with QFs, for the deferrable generation authorized today. To this end, Transphase recommends that we augment the solicitation packages for final Standard Offer 4 to incorporate integrated bidding procedures. In Transphase's view, this proposed

33 See D.92-02-075 in R.91-08-003/I.91-08-002.

consolidation would eliminate the need for "redundant" integrated bidding pilot(s) and prevent relitigation in a DSM proceeding of all the generation/supply-side issues currently being resolved in this Update.

PG&E, SDG&E, DRA, and GRA/IEP filed replies to the motion and were unanimous in their opposition.[34] They stated that including a DSM solicitation in this Update would be premature and would unduly complicate and delay the bidding.[35]

We deny Transphase's motion to consolidate. First, contrary to Transphase's assertions, an integrated bidding pilot is easily accommodated within the overall level of resource additions adopted in today's order. There is no basis for Transphase's apparent assumption that, unless the integrated bidding pilot "counts against" QF-deferrable generation, the entire resource plan could be subject to relitigation. As illustrated in Figure 7 above, a relatively small portion of total resource need will be subject to QF bidding over the 1992-1999 period (i.e., less than 1500 MW or 15%). An integrated bidding pilot (or pilots) could easily be subsumed within the remaining thousands of MWs of need, e.g., within the forecast of uncommitted DSM.

Second, we prefer to test various forms of DSM bidding on a pilot scale, before allocating a large amount of capacity through any single auction and form of bidding. This approach is consistent with PU Code § 747(c), which requires that we "assess

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34 GRA/IEP's reply was timely served but filed a day late. For good cause, GRA/IEP's request for leave to file late is granted.

35 SDG&E also notes that Transphase's petition to intervene is deficient under Rule 54 of the Commission's Rules of Practice and Procedure. We agree with SDG&E that Transphase "raises new issues...at the eleventh hour." We therefore deny the petition without prejudice. Although this ruling technically moots the motion to consolidate, we explain in the body of the opinion why such consolidation would not be appropriate.

the feasibility and implications of implementing the tested bidding systems" before making recommendations on whether DSM bidding systems should be used to fulfill future electric utility resource needs. We disagree with Transphase that the only "true test" of integrated bidding requires immediate implementation of the integrated bidding pilot(s) at a scale commensurate with supply-side bidding.[36]

Consideration of integrated bidding pilot(s) will remain in our DSM Rulemaking/Investigation. We leave the scheduling of the various phases of that Rulemaking/Investigation to the ALJ assigned to that proceeding.

### 3.3 How Transmission Access Affects This Decision

Growth in alternative generation capacity is only one step toward our achieving a fully competitive electric generation market. An efficient market in electric supply also depends on efficient use of transmission facilities. Utilities still control their transmission systems, and QFs have only such access to the wholesale market as the interconnecting utility is willing to provide. If a QF does not own its transmission system, and cannot arrange for a utility to transmit its energy, it cannot get its energy to the marketplace. Thus, the transmission sector remains a natural monopoly and a "bottleneck" to achieving full competition in the electric generation market.

The issue of transmission access affects this decision in a number of ways. It is significant for integration purposes, when a QF is selling power to an interconnecting utility. It is also

36 We also disagree with Transphase's assertion that the proposed consolidation could be accomplished without any disruption in the schedule for this proceeding or the DSM Rulemaking/Investigation. Transphase's assumption that proposals for integrated bidding protocols can be developed, adopted, and implemented without extending the auction schedule is unrealistic.

significant for wheeling purposes, when a QF uses the transmission system to transmit its output through an interconnecting utility's area to the purchasing utility's system.

Thus, in order to compete to serve a potential buyer, a QF must have reasonable access to the transmission system. A QF also needs to have reasonable assurance of the costs and other terms under which it may have its output integrated into an interconnecting utility's system or wheeled by the utility connecting the QF to the purchasing utility.

Furthermore, our bidding process needs refinement to allow direct comparison of an IDR's transmission costs with the transmission costs of the bidding QFs. These costs would then be included with all other costs of the bidders and of the IDR against which they are bidding. This means that specific information regarding an IDR's transmission costs should be reflected in the benchmark price. It also means that a QF needs to know in advance, from data published by the utility, what its transmission costs will be in order for the QF to properly determine its bid. The utility would then use these same published transmission costs in order to evaluate the bids and determine the winners. This process will further our goal of developing an environmentally sensitive least-cost resource plan which accounts for all the costs of power (as delivered to the utility load center) of the competing resource options.

For this reason we have instituted a parallel proceeding (I.90-09-050) where we are considering these key transmission issues. These two proceedings are closely linked, and we anticipate significant progress in the transmission investigation within the current Update cycle. This progress should include some

reflection of transmission costs and reasonable access to wheeling service as part of this Update solicitation.[37]

We recognize that SDG&E's system has special transmission considerations. Our transmission investigation and its impact on SDG&E's system have strategic implications that influence the size of the SDG&E solicitation in this Update. (See Section 5.1 below.)

3.4 How Strategic Preferences Affect This Decision

We have designed the Update process bearing in mind that the process must deal with many variables and many policy goals, some of which may conflict with each other.[38] Our first principles, with which everyone agrees, are that no forecast of future conditions is perfect, and that every resource plan will contain tradeoffs.

Modern resource planning is a combination of computer analysis and expert judgment. The computer analysis helps quantify potential problems (e.g., capacity shortfall, rising fuel expenses, high environmental costs) and likely outcomes given various assumptions. Expert judgment--not the computer analysis--is used to craft a solution (the resource plan) tailored to the problems and policy goals as these are perceived at a particular time. Expert judgment is always necessary because computer modeling results are no better than the necessarily uncertain input assumptions, and because some things are not (and may never be) quantifiable.

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37 See Section 8.1 on coordinating the schedule of I.90-09-050 with the Update.

38 There are conflicts inherent even in traditional least-cost planning. For example, we want "reliable" service but extreme degrees of reliability may require prohibitively expensive reserves of generation and transmission facilities. Resource planners have always had to balance reliability and cost. Recognition of air quality impacts simply adds another factor for planners to try to balance.

For these reasons, this Commission has always insisted that each utility's resource plan testimony explain how the utility is responding to uncertainty and incorporating strategic preferences in its plan. Virtually every party agrees with this in principle.[39]

Strategic preferences do not strongly affect the PG&E resource plan at this time. The reason is that PG&E's testimony shows little variation between the base case, alternative scenarios, and the recommendations of ER-90. Other parties' recommendations on IDRs and total MW for PG&E's solicitation do not differ markedly from PG&E's own position.

Strategic preferences are vital for SDG&E and Edison because the recognition of residual emissions costs shows that these utilities would benefit from increased investment in resources with low or no emissions. New resources become cost-effective earlier in the utility resource plans, more low-emission resources are cost-effective, and total MW of need increase somewhat, compared to traditional least-cost planning (i.e., planning that does not recognize residual emissions costs).

Ever since D.86-07-004, we have constrained final Standard Offer 4 solicitations to observe the CEC's integrated assessment of need. This means that for each utility, we generally will not make any <u>more</u> MW available for bidding in a given Update cycle than the CEC would find needed pursuant to its then-current

39 Unfortunately, Edison has presented its case in such a fashion as to obscure its actual preferences and its reasoning behind them. (See Section 6.1 below.)

Electricity Report.[40] We have expressly stated that in appropriate circumstances we might make fewer MW available.

In today's decision, the deferrable resources we identify for PG&E and Edison substantially correspond to the MW levels that the CEC has recommended for bidding in this Update cycle. Our consideration of SDG&E's strategic preferences and our own judgment on SDG&E's situation persuade us to authorize a small solicitation. The deferrable resources we identify for SDG&E amount to slightly more than half the MW that the CEC recommends SDG&E "acquire now."

Before discussing each utility's resource plan showings, we discuss below the key strategic considerations that the parties have debated.

### 3.4.1 Evaluation of Short-term vs. Long-term Resources

The Update and final Standard Offer 4 primarily address long-term electric resource needs met by construction of new plants or by long-term purchases. A resource plan, however, contains purchases of varying duration. The question has arisen whether the utility should test all potential resources by the environmental least-cost method, i.e., including the cost of residual air emissions.

The Commission concludes that, for this Update and until further order, utilities should evaluate short-term purchase options (those of five years duration or less) on a traditional least-cost basis, i.e., without factoring in residual emissions

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40 One circumstance in which a larger solicitation might be appropriate is where a major portion of a utility's resource mix were to become unexpectedly unavailable for a long period. Since the CEC has a standing committee that may consider modifying an Electricity Report in extraordinary circumstances, we think it is unlikely that this Commission would find itself without guidance from the CEC should a generation supply emergency arise.

costs.[41] Because there is inherent tension between this treatment of short-term purchases and other policy goals, all parties are invited to comment in future Updates on the impact of such treatment.

3.4.1.1 Usefulness of Short-term Purchases

Short-term purchases always have several advantages relative to other resource options. The most obvious advantage from the California perspective is that such purchases provide inter-regional balance, by allowing utilities to benefit from surplus generation and different peak load patterns that may prevail in other markets. The Pacific Northwest and Desert Southwest currently have surplus generation at certain times during the year, and the Pacific Northwest, in contrast with California, experiences its peak load during the winter. These circumstances enable a wide variety of sales and exchanges to take place between the regions, with cost savings for all participants.

There are other important advantages. New power plants, for economic and technical reasons, tend to be "lumpy" (100's of MW). A utility can often serve a small incremental need for capacity more cheaply through short-term purchases than through the construction of a new plant.

Short-term purchases can also serve various hedging strategies. Forecasts of need always have a degree of uncertainty, but short-term purchases can mitigate such risk by enabling the purchasing utility to delay commitment to building a new power plant until, e.g., anticipated load growth appears more certain. In fact, one valuable form of diversity for a utility system is to have resources of different and staggered duration, so that the

41 This definition of short-term resources was generally agreed to by the parties in the previous phase (Phase 1B) of this proceeding.

utility is neither flush with generation nor faced with sudden generation shortfalls.

To summarize, short-term purchases help an electric utility smooth its supply curve, maintain prudent reserves, and maximize its ability to participate in inter-regional wholesale markets. Such purchases will always play a part in least-cost resource procurement.[42]

3.4.1.2 Concerns with Short-term Purchases

The above enumeration of the advantages of short-term purchases also makes clear that a utility may have too great a reliance on them. Economic advantages associated with short-term purchases depend in part on the persistence of surplus generation on other utility systems. As these systems approach resource balance, bargains will disappear, and the purchasing utility would be better off building new plants. At that point, short-term purchases should not defer commitment to long-term generation resources.

Moreover, short-term purchases are a patch, not a structural solution. Edison and SDG&E, in particular, need to modernize, diversify, and clean up their present mix of power plants. Also, short-term purchases generally do not provide system stability benefits, such as voltage support, which SDG&E has argued are needed on its system. Short-term purchases help to minimize potential rate shock but they do not themselves accomplish these needed changes to the utility infrastructure. Too much reliance on

42 We note the CEC has netted out of its need assessment a substantial amount for "spot capacity" purchases, e.g., 700 MW for PG&E and 400 MW for Edison throughout the planning horizon. Short-term purchases also appear in the CEC's "committed" resource categories. (See generally Chapter 6 ["Integrated Assessment of Need"] of ER-90.)

short-term purchases could exacerbate the existing structural problems on the utilities' systems.

#### 3.4.1.3 Why Short-term Purchases Should Be Evaluated Without Factoring in Residual Emissions Costs

In D.91-06-022, we determined that since emissions impose measurable costs upon our society, they should be accounted for in evaluating long-term purchases. This resource plan phase, and the resultant bidding cycle, is the first time that a residual emission analysis will be applied to long-term purchases. In short, it is the first time that environmentally sensitive least-cost planning is put into practice.

Since we are in this transition phase, it is useful to maintain our traditional least-cost planning approach when evaluating short-term purchases. Although we have determined that taking externalities into consideration provides a better indication of the real cost of generation, not applying a residual emissions analysis to short-term purchases will ease the transition phase, and will help cushion any potential rate or other impacts that may result from incorporating externalities in evaluating long-term purchases.

We expect this policy to chiefly affect output from plants that have already been built. In other words, utilities will have less of an incentive to build new power plants with high levels of emissions solely for the purpose of making short-term sales into the California market. Short-term purchases do not provide the kind of price signal and long-term commitment by our California utilities that would encourage other utilities to make such investments. By the same token, even if we factor in residual emissions costs in evaluating short-term resources, this may not result in the clean-up of the existing plants, especially if there remain other buyers in the market.

3.4.1.4 Interim Nature of this Policy

We are concerned that this bifurcated analysis (i.e., applying environmentally sensitive least-cost planning to long-term purchases or new construction and traditional least-cost planning to short-term purchases) might lead to too much reliance on short-term purchases. Such reliance could increase costs and ultimately obstruct many of our resource planning goals (to modernize existing energy infrastructure, develop renewable technologies, assist air quality compliance, invest in DSM, ensure reliable service). Therefore, we stress this bifurcated approach is an interim policy that we will carefully monitor and revisit. Furthermore, we recognize that as other state and federal regulators increasingly factor externalities into their own resource decisions, it may be appropriate to modify this policy.[43]

3.4.2 "Portfolio" Strategies

Investors know that concentrating one's assets in a single investment, or a single type of investment, is generally riskier than holding a diversified portfolio. A similar concept applies to electricity resource planning, and especially to developments in resource planning over the past 10-20 years.

For example, we have come to recognize that DSM programs (conservation and load management), among their other advantages in comparison to new power plants, can help diversify our resource mix. Many believe DSM is less risky than building new plants, and in any case, DSM involves a different set of risks; the things that

43 For this phase, each utility was directed, in performing its long-term resource plan cost-effectiveness analysis, to "count air emission costs for all resources once they are added to its system, even if the added resource is short-term." (ALJ Ruling, July 12, 1991, mimeo. p. 6.) This direction is consistent with today's decision; the intention is to ensure residual emission costs are taken into account when testing potential long-term resources. The ruling is affirmed and will govern resource plan modeling in future Updates.

cause plant construction to incur overruns may not increase the cost of DSM at all.

We have also come to recognize the value of having our utilities look to independent sources and to other utilities for supply-side resources, and recently for demand-side resources as well. This change in procurement strategy has many benefits, such as competitive pricing, technical innovation, and diversity of size, location, and technology.

These examples are already familiar. The Update process is a product of this procurement strategy, and at the same time it brings additional types of portfolio planning issues into focus.

An important reason why we have frequent Updates (every two years) is that our forecasts of future conditions are constantly changing. Thus, resource plans must be revised frequently, and utilities must always have the ability to make resource commitments between Updates.

Also, we would not want to have a drastic makeover of any utility system in any one Update. For this reason, even if we had not already accepted the CEC's limit on need for this solicitation, we would not require Edison, for example, to solicit all the 1700 MW of clean generation that the base case analysis says would be cost-effective. That would be putting too much weight on the current forecast.[44]

What we here call portfolio considerations influence today's decision significantly. They are one reason why we have both gas-fired and renewable IDRs for each utility. They are the main reason why we limit the IDRs for SDG&E to less than 60% of the additional capacity that the CEC recommends SDG&E acquire now.

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44 Another concern might be whether the size of the solicitation would be so large as to drive up the market price, compared to the price that could be obtained through a series of smaller solicitations.

The IDRs designated for PG&E constitute a tiny portion of its system capacity; they also do not significantly increase the number of QFs on PG&E's system even if they are fully subscribed. Edison's IDRs constitute a somewhat higher but still quite small portion of the Edison system.

The situation is different for SDG&E, which has significant reliability-based need over the next eight years, and which under all of its scenarios would be increasing its system capacity by one-third or more. The limits we place on SDG&E's solicitation keep the QF contribution to its total capacity in line with the other utilities. They also ensure that SDG&E will fill its large resource needs from a variety of sources, not just QFs and not just this solicitation.

3.4.3 "Go Short" Strategies: Non-biddable Need

SDG&E has supported in this Update, as in the previous Update, a strategy which always reserves, for provision through short-term purchases, 50% of its perceived long-term need. SDG&E attributes much of its success in lowering its average electricity rates below those of PG&E and Edison to its use of this "go short" strategy.

There are several advantages to such a strategy, according to SDG&E. The strategy positions the utility well to take advantage of low-priced supply, which SDG&E says will continue to be available in the wholesale electricity market. Also, the strategy enables the utility to avoid premature commitment to long-term resources.

We approve SDG&E's position in principle, while we continue to be skeptical about SDG&E's formulaic application of that principle. "Go short" strategies serve many of the same purposes as "portfolio" strategies in that they hedge against many kinds of risk. We have also indicated that short-term resources should always have a role to play in resource procurement. (See Section 3.4.1 above.) But SDG&E has no convincing explanation of

why the reservation should be 50%, or any other stated fraction, rather than a current judgment about what market conditions at the time of the current forecast suggest would be appropriate.

"Going short" is plausible for a small or mid-sized utility (like SDG&E) whose neighboring utilities have surplus capacity. How much that utility should go short depends on particular circumstances, such as the projected persistence of surplus capacity, the utility's ability to meet reserve margin and system stability criteria, the lead-times of various resource options, etc. A utility that always goes short may find itself buying in a seller's market. While it is true that premature commitments are costly, the same may be said of commitments made too late.

Although we grant SDG&E's request that we designate substantially less capacity for this solicitation than the total potentially deferrable capacity shown in ICEM analysis, our reasons for doing so are primarily those discussed in the preceding section and in Section 5.1 below. SDG&E will have to produce a more rigorous and more circumstantial demonstration of its "go short" strategy than this record contains for us to accord that strategy much independent weight.

The effect of a solicitation that is smaller than a utility's total need is to leave the utility with discretion, until the next Update, over how, when, or even whether to acquire this needed but not biddable capacity. The utility's exercise of that discretion would be subject of course to our traditional reasonableness review.

### 3.4.4 Use of Base Case and Alternative Scenarios

Our base case scenario for each utility in the Update derives, with very limited exceptions, from the CEC's supply and demand forecasts in its latest Electricity Report. We also give utilities broad latitude to explore the effects of uncertainty, which they generally do through alternative scenarios. The goal is

resource plans that work well even if the future differs from the forecasts, as it always does in greater or lesser degree. There will probably always be some tension between giving adequate scope to this uncertainty analysis without having the alternative scenarios displace the base case and the CEC's "integrated assessment of need."

In this Update, we have analyzed many scenarios. Some of these scenarios indicate large quantities of deferrable capacity, in excess of the CEC's need assessment, for SDG&E and Edison. We apply various strategic preferences (our own and the utilities') to remain consistent with ER-90 in our designation of IDRs, and we consult both strategy and the scenarios to decide on optimal IDR timing.

The base case indicates "ideal" timing, i.e., how soon the utility would add a particular resource were it not constrained by the permitting and construction process. QFs often have shorter lead-times than utility-owned resources, so it makes sense to show the IDR in the first year the IDR becomes cost-effective even though the utility itself could not build the IDR that fast. Now that residual emission costs are included in ICEM analysis, "clean" resources are cost-effective sooner. In the case of SDG&E and Edison, many resources are cost-effective early in the planning period, too soon even for most QFs to compete against.

We will continue to have the base case represent ideal timing of resource additions. The usefulness of this approach was well demonstrated in this phase of the Update, where it revealed the substantial potential benefits from emissions reduction on the SDG&E and Edison systems. Use of so-called "realistic" lead-times would have masked this important information.

We do not rely on the base case for IDR timing, however. We have chosen instead on-line dates that will permit a wide range of QFs (both long and short lead-time developers) to bid. For all three utilities, we spread out the IDRs over more than one year to

minimize lumpiness and possible rate shock. PG&E and Edison do not have significant reliability-based need, so we assign their IDRs to the later years of the deferral window. SDG&E does have reliability needs, and as a result we assign earlier on-line dates to its IDRs.

3.4.5 Purchases From Existing Plants

We have previously described how our policy on short-term purchases ensures an appropriate continuing role for such purchases without compromising the long-term goal of achieving a resource mix based on environmentally sensitive least-cost planning. (See Section 3.4.1 above.) Some commenters would preserve a broader role for purchases from existing plants by ignoring residual emissions in cost-effectiveness analysis of any such purchase, even one for a 30-year term. These commenters argue that existing plants would run anyway, perhaps by selling their output to utilities not regulated by this Commission.

We reject this argument. If accepted, it would subvert the policies of PU Code § 701.1. First, the proposed "existing plant" exception would commit California indefinitely to a policy distinguishing emissions costs solely on the basis of when the emitting plant was built. While California utilities would still be constrained from directly adding such generation by building it themselves, anyone else could build a plant with high emissions, and California utilities could thereafter purchase its output because it would then be an "existing" plant. Instead of getting a message that California will prefer resources with low emissions, clever competitors would quickly realize that the "existing plant" exception will swallow the rule and reward the cheap supplier, no matter how high its emissions are.

Second, every resource that goes into a long-term plan necessarily backs down some other resource. Every long-term purchase from an existing plant means that some amount of DSM, or repowering, or renewables development won't happen. As long as

some significant category of long-term resource option is excluded from residual emissions valuation, we lengthen or thwart altogether the transition to a less polluting, more efficient resource mix to serve California.

4. PG&E's Resource Need

We designate two IDRs for PG&E.[45] Specifically, we designate as IDRs the repower of Hunters Point Units 2 and 3, for a total of 221 MW net capacity, and a variable speed wind IDR of 22.5 MW effective capacity (150 MW gross capacity). These two IDRs, taken together with PG&E's overall resource additions, are appropriate for PG&E during this Update cycle. The overall resource additions during the deferral window include 700 MW of spot capacity purchases and about 2500 MW of uncommitted DSM.[46]

PG&E also recommended that the Hunters Point Repower be designated as an IDR, and that only QFs located in San Francisco and Northern San Mateo County should be eligible to defer the repower. We agree with PG&E and adopt this recommendation. (See Section 4.2.2 below.) PG&E's filing indicates that the Hunters Point repower is a cost-effective resource addition in 1992; however, PG&E's system does not have reliability-based need, so we set an on-line date of 1997 for this repower in order to maximize competition among QF bidders.

We designate the variable speed wind IDR as a set-aside in compliance with PU Code Section 701.3. That is, only renewables

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45 See Figures 1 and 4, following page 3 above, summarizing the parties' positions on IDRs for PG&E and the on-line dates we approve. As Figure 1 makes clear, there is substantial agreement among the parties regarding deferrable capacity additions for PG&E.

46 Because spot capacity purchases and DSM are not deferrable by QFs, about 93% of PG&E's resource need during thus Update cycle will come from sources other than QF bidding. Uncommitted DSM programs are projected to fill about 75% of PG&E's need over the next eight years.

may bid against the wind IDR. PG&E originally recommended the variable speed wind IDR but later supported a single speed wind IDR of a lower capacity (3.8 MW effective) after discovering a "modeling error." We approve PG&E's original recommendation for reasons stated in Section 4.2.1 below. Since PG&E originally found the variable speed wind IDR to be cost-effective in 1998, we adopt 1998 as the on-line date for this IDR.

Our conclusions regarding the Hunters Point Repower are consistent with ER-90, which found the repower needed. Although ER-90 designated the net capacity of the Hunters Point Repower at 188 MW, the difference in MW reflects PG&E's newer version of the project which it presented in this resource plan phase of the proceeding. Although the wind IDR is beyond ER-90's need assessment, it is a small amount of capacity, especially for a utility system as large as PG&E's. Designating this wind IDR is also appropriate in order to meet the statutory set-aside requirement.

## 4.1 Critique of PG&E's Resource Plan Analysis

There was relatively little controversy regarding PG&E's resource plan filing. Overall, we believe that PG&E has made a persuasive showing, subject to the qualifications set forth below.

PG&E presented a base case plan and an alternate case using the Nevada Public Service Commission's residual emission values. PG&E then applied a three-step uncertainty analysis to both plans before reaching a determination that its base case plan is its preferred plan.

PG&E's uncertainty analysis used ranges of load growth and fuel prices as proxies for the host of resource plan input variables that could have been tested. PG&E then modeled high-, medium-, and low-resource need scenarios, with PG&E's base case as the medium-need scenario. PG&E also assigned probabilities of occurrence for each scenario, and again for each scenario used ICEM to develop a least-cost plan.

PG&E then quantified the impact of pursuing the "wrong" plan (seeing what extra costs would result, e.g., if the future turned out to be low-need when the utility had pursued the high-need plan). The base case plan seemed to work best although the range of outcomes was quite small. Finally, PG&E considered various hedging strategies that would enable it to reduce costs in the event of forecast error.

GRA/IEP's and CEERT's overall criticism of PG&E's analysis is that it did not contain a sufficient range of cost-effective alternative resource plans from which to consider the most appropriate plan. We agree that PG&E's uncertainty analysis provided relatively little insight.

A major uncertainty for PG&E is residual emission costs. PG&E is using moderate interim values (generally less than 30% of those applicable to Edison and SDG&E) because the air quality districts in PG&E's service area are developing the studies and programs from which compliance measures and costs will be derived. (See D.91-06-022, mimeo. p. 30.) PG&E could have modeled a wider range of residual emissions costs but apparently chose not to do so. As a result, we have no information on what hedging strategies might be appropriate if, for example, PG&E is required to reduce NOx emissions.[47]

We do not question PG&E's fundamental tenet that only a limited number of variables need be tested in order to reasonably investigate uncertainty. We also accept the notion that high and

47 Under the California Clean Air Act, air quality districts are not solely concerned with their own attainment status but must also take steps to reduce transport of pollution out of their districts if they are contributing to attainment problems downwind. Thus, PG&E could be strongly affected if transport studies now in progress support findings of the Air Resources Board that emissions from the San Francisco Bay Area are contributing to non-attainment in the San Joaquin Valley.

low ranges should be tested. However, both the variables and the ranges must be chosen with care. This appears to be an appropriate topic for workshops when we begin the next Update cycle.

Parties have also articulated more particular concerns regarding PG&E's filing. For example, GRA/IEP argue that PG&E should submit a supplemental filing because of a problem in the way PG&E modeled the stream of capital costs associated with its wind IDRs. Although we agree with GRA/IEP that PG&E's method for treating capital costs does not appear appropriate, we do not believe supplemental filings are necessary. However, this problem should be rectified in later Updates. (See Section 4.2.1 below.) Similarly, although we share many of DRA's and GRA/IEP's concerns regarding the level of uncommitted DSM in PG&E's plan, we do not believe that supplemental filings are necessary to address this issue. (See Section 3.2.2 above.) Finally, since we find a 22.5 MW wind IDR in PG&E's deferral window, we do not agree with GRA/IEP and CEERT that it is necessary for PG&E to calculate a fuel diversity premium at this time.[48]

## 4.2 IDRs

### 4.2.1 Wind

PG&E should solicit bids using as benchmark a variable speed wind IDR of 22.5 MW effective capacity (150 MW gross capacity). Only renewable QFs may bid against this IDR. This results in a smaller set-aside for PG&E than for Edison or SDG&E, but PG&E has a much more diverse resource mix than the latter utilities.

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48 PG&E was the only utility to propose a comprehensive fuel diversity premium valuation method for this Update cycle. However, this issue was removed from consideration in this Update cycle because renewable resources appeared in the deferral window for all three utilities.

PG&E originally supported the variable speed wind IDR but later supported a single speed wind IDR of lower capacity (3.8 MW effective, 25 MW gross) after discovering a "modeling error" in the treatment of operating and maintenance (O&M) costs. PG&E explained that, after correcting this error, the single speed machine became more cost-effective than the variable speed machine, even though the former has higher capital costs. An additional result, according to PG&E, was that the variable speed machine did not become cost-effective until beyond the eight-year deferral "window."

U.S. Windpower supports PG&E's original recommendation, which uses data U.S. Windpower included in a quote requested by PG&E for a "turnkey" wind project. PG&E Witness Katz conceded on cross-examination that PG&E had assumed a higher capacity factor for the single speed than for the variable speed machine, and that if the same capacity factor were assumed for both machines, the latter would be more cost-effective. (RT 3182-91.) Moreover, PG&E did not base its assumption on any judgment regarding the relative merits of the two machines. Instead, PG&E had in mind a specific company-owned site with outstanding wind characteristics but insufficient area to support the larger project. (Id.)

We reject PG&E's reasoning. Either type of machine could be built at PG&E's site, so PG&E would need to justify its preference for the more expensive machine on some consideration of the different designs. There was no such consideration. We also find implausible the notion that only one small site in California has the wind characteristics PG&E claims. If there were such a site, however, it would be more appropriate to develop a wind IDR based on more realistic environmental conditions.

We also reject PG&E's proposed single speed IDR because it is too small to be worth troubling over. In D.91-09-073, mimeo. pp. 10-11, we suggested that generation resource options should meet a minimum size criterion to justify the expense of holding an

auction. The telemetering requirement for QFs (10 MW and above) on the PG&E and Edison systems is a logical threshold for IDRs on those systems.[49]

We designate the variable speed wind IDR a set-aside in compliance with PU Code § 701.3.[50] This is superior to setting aside a portion of the Hunters Point IDR for bidding by renewable QFs. First, the geographical restriction we place on bidders against that IDR make it unsuitable for set-aside purposes. Second, renewable IDRs provide a more appropriate bidding benchmark for renewable QFs.

U.S. Windpower argues in its brief that PG&E should be required to build the variable speed wind IDR if QFs do not fully subscribe that capacity. U.S. Windpower reasons that its "turnkey" quote depends on the utility owner's financing the project at the utility cost of capital, which is lower cost than that available to a QF developer. PG&E opposes this suggestion and, supported by Edison, moves to strike portions of U.S. Windpower's brief as relying on facts not in evidence. (U.S. Windpower participated through briefing and cross-examination but did not offer testimony.)[51]

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49 See D.87-05-060, 24 CPUC 2d 253, 275. Telemetry provides real-time information to the utility dispatcher on the output from each telemetered plant. SDG&E has a much smaller system and correspondingly lower telemetering requirement (two MW and above), which we shall use as the IDR threshold for SDG&E.

50 Concerning the capacity factor to be assumed for the IDR, PG&E should use 27% or a lower capacity factor, calculated as suggested by U.S. Windpower in its reply comments on the Proposed Decision.

51 We deny PG&E's motion. PG&E's own testimony indicates this IDR derives from a "turnkey" quote, which Webster's New World Dictionary (2d College Ed.) defines as "a method of construction whereby the contractor assumes total responsibility from design

(Footnote continues on next page)

In D.91-06-022, we urged the utilities to discuss cost data with QF developers. (Id., mimeo. p. 37.) Turnkey projects may provide a way to lower the cost of renewable technologies and increase utility participation, both of which seem desirable. Moreover, the contractor in a turnkey project bears the risk of developing the project at the contract price; this factor largely negates our reasoning in deciding not to hold the utility to the benchmark price if it builds the IDR. (Id., mimeo. pp. 71-74.)

We will require PG&E, subject to two alternative conditions, to pursue the variable speed wind IDR or another renewable project if the IDR is not substantially fully subscribed. First, PG&E may itself develop the renewable capacity if it is willing to accept the benchmark price as a cost cap. Second, if PG&E chooses not to develop the renewable capacity itself, it must pursue the IDR if U.S. Windpower is still willing to proceed under the terms and conditions of its turnkey quote.

We impose this requirement because this IDR is a set-aside. We think the legislative policy expressed in PU Code § 701.3 requires us to ensure each utility acquires some additional amount of renewable generation. We do not adopt a generic policy for IDRs based on data from turnkey quotes. We may consider such a policy in the methodology phase of this proceeding or in later Updates.

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(Footnote continued from previous page)

through completion of the project." The assertion regarding relative costs of capital follows from the relatively higher risks QF developers bear, which this Commission has acknowledged many times. (See, e.g., D.91109, 3 CPUC 2d 1, 15 (1979).) These two propositions form the factual basis for U.S. Windpower's argument, which for the most part goes to policy matters properly raised on brief.

Finally, for later Updates, we note a problem in the way PG&E modeled the stream of capital costs associated with its wind IDRs. Briefly, a "balloon" occurs at the end of the variable speed machine's 20-year useful life. (See Exhibit 300, Table 11A.) It appears that PG&E created a levelized cost stream based on a 30-year life, so a large payment has to occur in the 20th year or there would be an under-recovery. We agree with GRA/IEP that this method for treating capital costs does not appear appropriate either for cost-effectiveness analysis or for payments under final Standard Offer 4.

4.2.2 Hunters Point Repower

PG&E's filing indicates the repower of Hunters Point Units 2 and 3 is a cost-effective resource addition in 1992. PG&E recommends that the repower be deferrable only by QFs located in San Francisco and Northern San Mateo County. We conclude that the repower of Hunters Point Units 2 and 3 is cost-effective, that it is a deferrable resource, and that as PG&E recommends, only local area QFs should be eligible to defer the repower.

According to PG&E, the Hunters Point repower would increase the existing 214 MW capacity of Units 2 and 3 to 435 MW, resulting in a net increase of system capacity of 221 MW. The repowering would significantly improve the heat rate, compared with the existing units, and would reduce fixed O&M costs. PG&E also indicates the repower would defer a transmission line expansion otherwise needed to serve future area loads and to meet local reliability needs.

In support of the recommended geographical restriction, PG&E cites its San Francisco Operating Criterion. The criterion creates a local reliability-related dispatch protocol, which requires that local generation capacity be sufficient to meet 50% of San Francisco loads during daytime hours, except Sundays, to protect the San Francisco downtown network from a major disturbance to the San Francisco power supply. The criterion makes San

Francisco subject to its own dispatch protocol, partially de-linked from the total system dispatch logic.

PG&E's cost-effectiveness analysis includes benefits associated with heat rate improvement (production cost savings), capacity value of the incremental capacity (221 MW), lower fixed O&M costs, emission reductions, line loss reductions, and the deferral of a transmission line expansion. PG&E also quantifies what it considers unique "local" benefits that arise because of the peculiarities of San Francisco's location and consequent constraints in serving that load. In its calculation, "local" benefits equal the difference in total benefits assigned to Hunters Point and a similar cost-effective repower located elsewhere in PG&E's service area.

DRA asserts that PG&E has failed to satisfy the four-part test for nondeferrability of specific projects. We disagree. PG&E demonstrated the cost-effectiveness of the repower, identified and quantified its unique characteristics, and quantified a "subtractor" which it would apply to non-local QFs. An unrestricted bid, as recommended by DRA, would not defer or eliminate the transmission system upgrades.[52]

DRA also suggests that PG&E should have examined alternatives to the repower, such as other generation options and transmission upgrades. While PG&E did not present an analysis of such alternatives, we generally agree with PG&E's argument that additional local generation is less likely to be affected by earthquakes than transmission lines which are exposed to earthquake hazards over an extended distance. As to alternative local

52 At best, an unrestricted bid might leave ratepayers indifferent by financing the cost of the upgrades through the use of a subtractor.

generation options, screening of resource options before testing in ICEM seems sufficient for this purpose.

GRA/IEP recommend that any restriction on the bid be limited to the existing capacity of Units 2 and 3; QFs could bid for the incremental capacity regardless of their location. GRA/IEP do not believe that PG&E's estimated annual six MW load growth is sufficient cause for constructing the increment in or near San Francisco. However, PG&E indicates that local annual load growth could range from 6-14 MW.[53] The repower both defers transmission line construction to meet that growth and satisfies San Francisco's unique reliability needs.

We also note that the existing capacity of Units 2 and 3 would be assumed in an analysis of whether to construct a new transmission line; thus, it is the incremental capacity which would defer such construction. For these reasons, the entire capacity of the repower, subject to the geographical restriction, should be subject to QF bidding.[54]

CEERT contends that PG&E does not need additional generation in San Francisco for reliability and that, to achieve the claimed local benefits, PG&E need repower only one unit, not two. We have already noted local load growth, however, and we accept PG&E's testimony, as did the CEC in ER-90, that the two-unit repower is optimal.

The geographical restriction is unusual, and the potential QF capacity that could be developed for interconnection

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53 PG&E's six MW annual load growth estimate for the San Francisco area may be low since it assumes that Customer Energy Efficiency programs will reduce by eight MW the forecasted 14 MW growth.

54 But for the constraints of the San Francisco Operating Criterion, we would have made the Hunters Point repower deferrable by QFs regardless of their location.

at the specified substations may well be insufficient to fully subscribe this IDR. We believe even a partial subscription this close to a major load center would have significant benefits. As with any undersubscription, the utility will have the ability to decide after the auction whether to pursue the IDR as originally configured, downsize the IDR, pursue some other resource option, or simply defer reconsideration to a future Update.

Considering the geographical restriction, we direct PG&E to make an outreach effort tailored to this narrow solicitation. PG&E should take vigorous steps to alert potential bidders, many of whom may be small concerns not actively involved in or aware of the Update.

5. SDG&E's Resource Need

SDG&E's IDRs total 473 MW.[55] Specifically, we designate the Encina 1 repower (273 MW net) and 200 MW of geothermal as SDG&E's IDRs. We set aside half of the geothermal capacity for renewable bidders, pursuant to PU Code Section 701.3. The Encina 1 repower and geothermal IDRs result in a reasonable total solicitation that will reduce emissions and help diversify SDG&E's resource mix. SDG&E's overall resource additions during the deferral window include 100 MW of spot capacity purchases, about 400 MW of uncommitted DSM, and 687 MW of other generation.

In its Strategic Preference Plan, SDG&E also designated the Encina 1 repower as an IDR. SDG&E needs resource additions now. Although repowers were found cost-effective as early as 1992, we choose later on-line dates in order to reduce lumpiness and maximize competition among QFs while obtaining generation for SDG&E's system soon. We therefore establish the following on-line

55 See Figures 2 and 5, following page 3 above, for summaries of the parties' positions on IDRs for SDG&E and of the on-line dates we approve.

dates for the Encina repower IDR: 1995 will be the on-line date for 135 MW and 1996 will be the on-line date for 138 MW. The benchmark price for both years will be based on the Encina 1 repower's costs and emissions characteristics, with appropriate escalation for the later on-line date.

Although some of SDG&E's scenarios show geothermal additions to be cost-effective as early as 1992, we designate 1997 as the on-line date for 100 MW of geothermal and 1998 as the on-line date for the other 100 MW of geothermal. Half of each 100 MW is designated as a set-aside. Staggering the IDR on-line dates from 1995 through 1998 will provide SDG&E with planning flexibility and avoid lumpiness problems.

The result we reach today is close to SDG&E's recommendation. SDG&E finds about 745 MW of deferrable generation, and recommends that about half of that (375 MW) be subject to QF bidding during this Update cycle. Our result stops well short of filling all need shown in ER-90. There, the CEC finds that SDG&E needs 1,292 MW of new resources by 1999, of which 850 MW (including a set-aside for renewables of 460 MW) are categorized as "acquire now" and the remaining 442 MW are deferred to ER-92.[56] Our decision results in QFs bidding for 56% of the total MW that ER-90 recommends SDG&E "acquire now."

Our choices of IDRs and total capacity for this solicitation are influenced by the high quality of SDG&E's resource plan testimony, which convincingly sustains SDG&E's strategic preferences. SDG&E has acknowledged its substantial need for new resources, and has sensibly assessed its resource options. We

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56 DRA, GRA/IEP, and CEERT all recommend a larger solicitation for SDG&E (1017.5, 1178, and 1500 MW, respectively). For reasons set forth in the text and elsewhere in the decision, we find that a smaller solicitation is appropriate for SDG&E at this time.

differ with SDG&E's bottom-line recommendation only because of its inadequate representation of renewables.[57]

Our designation in this Update cycle of fewer MW than the CEC has recommended as "acquire now" is consistent with sound strategy for SDG&E. SDG&E will be able to fill its remaining need, and respond to the CEC's recommendation of renewable capacity beyond that amount set aside in today's decision, from its other resource options. Those options include the responses to SDG&E's requests for proposals issued in preparation for its resource plan showing.[58]

5.1 Critique of SDG&E's Resource Plan Analysis

SDG&E presented a convincing analysis of its system, needs, and strategies. It began by seeking proposals for short-term and long-term purchases. This request elicited offers to sell power from many utility and nonutility generators. SDG&E also examined many possibilities for developing new generation and modernizing its existing plants. Most important from our perspective, SDG&E became the first electric utility we know of to complete a cost-effectiveness analysis applying the same dynamic methodology to DSM and generation options. We have, as a result, a

57 We note that SDG&E's proposal for renewables (100 MW) is low under the Nevada scenario (i.e., the scenario using lower emissions values for plants sited in attainment areas). The Nevada scenario shows 350 MW of renewables to be cost-effective for SDG&E over the next eight years.

58 We have preferred to use SDG&E projects as IDRs instead of the long-term purchases shown in SDG&E's Strategic Preference Plan. The reason is greater flexibility--the SDG&E projects will still be available after the bidding, should it appear prudent at that time to pursue them, while the purchases may or may not be still available. Also, the purchases all appear to be fossil-fired. Our decision not to have long-term purchase IDRs at this time does not preclude our using purchased-power IDRs in other circumstances.

thoughtful and thorough examination of SDG&E's resource options existing as of the preparation of its compliance plan.

SDG&E also performed ICEM analysis on a large number of scenarios and presented the results in a clear and useful manner. With some exceptions (see, e.g., Section 5.2.1 below), SDG&E was careful to set forth both the data it relied on and its sources for the data.

SDG&E, moreover, was by far the most forthcoming of the utility respondents in discussing its corporate strategies. This careful marshaling of options, analysis, and strategies is a model for future Updates.

The key issue for SDG&E is not whether it needs resources. SDG&E vigorously pursues wholesale purchases, and so it will typically show some need in each Update.[59] That is the case here. SDG&E sees risk in committing to all of its perceived need at any given time because such commitment could inhibit its ability to utilize the wholesale market to greatest advantage. SDG&E sees particular risk in full commitment at this time because SDG&E believes the long-term outlook for gas prices reflected in its base case is much too high, with resulting strong potential for selecting the wrong quantity and mix of resources to fill that need.

SDG&E asserts that its management of its short-term and long-term resources has enabled it to move from a position as the highest cost supplier among the utility respondents at the beginning of the 1980s to its present position as lowest cost supplier. We earlier criticized SDG&E's "go short" rule-of-thumb (see Section 3.4.3 above), but SDG&E's showing clearly demonstrates

59 SDG&E analyzed a scenario using traditional methods (no costs imputed to residual emissions) and still showed need for over 1,000 MW during the next eight years.

the feasibility and desirability of something considerably less than full commitment at this time. Our own thinking on "portfolio" strategy also helps us reach substantially the same conclusions as SDG&E recommends.

Last but not least, SDG&E's transmission situation inclines us to limit the solicitation for this Update. SDG&E has a much smaller and less varied service area than do PG&E and Edison. The evidence suggests there is little potential for development of additional independent generation within SDG&E's service area, so most of the bidders will probably be off-system.[60] This is a problem because (1) SDG&E, compared to PG&E and Edison, occupies a transmission cul-de-sac, and (2) the wheeling arrangements for the coming solicitation are still being worked out. While the negotiating conference in I.90-09-050 produced encouraging progress, it seems prudent to start the wheeling program with a reasonably small solicitation.

We do not entirely agree with SDG&E on the impact of gas price uncertainty. However, we have accepted SDG&E's recommendation, supported by the CEC, that the ER-92 gas price forecast be used for purposes of bid evaluation. (See Section 9.1 below.)

SDG&E also goes too far in dropping renewable capacity almost entirely from its Strategic Preference Plan. Our addition of 100 MW of geothermal to that plan (for a total renewable IDR capacity of 200 MW) better balances our planning objectives for this Update.

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60 We anticipate, in contrast, that the majority of the bidding in the PG&E and Edison auctions for this Update will come from on-system QFs.

5.1.1 Repower of South Bay Unit 3

In A.91-08-028, which we have consolidated with the Update, SDG&E sought a Commission finding of nondeferrability for a proposed repower/desalination project at the South Bay Power Plant, not specifying which unit.[61] The application stated that the repower would add 300-455 MW, and it requested that the Commission make the finding of nondeferrability contingent upon the repower's link with the desalination facility.

In subsequent testimony and brief, SDG&E changed its position. It now seeks nondeferrability for a 455 MW repower of South Bay Unit 3, whether or not an associated desalination facility is built. SDG&E cites voltage support and land use benefits of developing an existing site to justify a finding of nondeferrability for this repower as a stand-alone project.

GRA/IEP and DRA oppose SDG&E's request, which they say does not satisfy the Commission's criteria for nondeferrability on a project-specific basis. We agree and therefore reject SDG&E's request.

In D.86-07-004, we recognized that a specific project may have "such complex impacts on the utility's existing system that it would be difficult to avoid them...because their system impacts would still be desirable or be impossible for QFs to provide." (21 CPUC 2d 340, 380.) We adopted the following criteria for a showing that a specific project should be nondeferrable.

> "This showing must (1) establish the project's cost-effectiveness, (2) set forth the aspects

61 In its application, SDG&E also requested ex parte and expedited treatment. By ruling (August 23, 1991), the assigned ALJ consolidated the application with the Update, under the rationale that the Update permitted more expedited treatment of SDG&E's request than a separate application. The ALJ rejected ex parte treatment, however, holding that disputed issues of fact and policy made a hearing appropriate. We affirm the ALJ ruling in all respects.

> of the project claimed to justify a finding of nondeferrability, (3) quantify the economic and operational benefits of such aspects, and (4) describe the impact of attempted deferral through the use of 'adders' and standard offer contracts." (Id.)

As discussed below, SDG&E's showing is inadequate under these criteria.

SDG&E has shown that the repower, as a stand-alone project, is cost-effective in a number of its scenarios. Now that SDG&E itself has delinked the repower from the desalination facility, some of our concerns regarding the uncertainty of that facility are moot.[62] However, even accepting the showing of cost-effectiveness, SDG&E has failed to satisfy the other three criteria.

Specifically, SDG&E has failed to show that the repower provides unique and nonduplicable benefits, through either an associated desalination facility or the alleged voltage support and land use benefits, such that a deferral of the repower would be wasteful.

For example, the Commission recognizes the need for sources of fresh water supply for Southern California. As we have already noted, however, the record is silent on the specifics of the desalination facility, or even its feasibility. If the desalination proves cost-prohibitive, the facility would confer no benefit, no matter who bears the costs. Moreover, SDG&E has not demonstrated to what extent the desalination facility depends on the repower. If this or a similar facility could go forward by

62 We remain concerned that ratepayers not subsidize an associated desalination facility. SDG&E says there would be no such subsidy, but since the record contains no detailed agreement with the water agency, we cannot determine whether such agreement would fairly apportion the financial and other risks of the facility.

buying steam or electricity from SDG&E or another source, then the repower may have a benefit from association with the facility, but society would not lose the benefits of desalination if this specific repower were deferred.[63]

SDG&E now argues that the most important reason for granting nondeferrability is that the repower will provide needed voltage support. SDG&E does not document this need for voltage support, nor does it establish that this project is uniquely suited to meet that need, or even that the repower will meet the need.[64] We hold that SDG&E did not meet its burden of proof on this issue.

Finally, SDG&E claims land use benefits of using an existing site, as opposed to developing a new site. The asserted land use benefits are not based on geographical or other land use considerations specific to South Bay Unit 3 and SDG&E's system. SDG&E instead argues generally that utilizing an existing generation site is preferable to developing a new site. This proposition is not self-evident. For example, SDG&E does not convincingly establish whether the repower and continued

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63 We have a further concern with SDG&E's assertion of the desalination facility and land use benefits to support its request. In D.86-07-004, we stated that a request for a finding of nondeferrability must depend on the specific project's impacts <u>on the utility system</u>. Neither desalination nor land use are system impacts. This Commission has a duty to regulate electric utility service and rates, and to consider in resource planning certain externalities (e.g., air emissions) pursuant to legislative direction. Since we hold that SDG&E has not justified a finding of nondeferrability anyway, we will not address the generic issue of whether non-system benefits are ever a proper basis for a finding of nondeferrability. We note, however, that attempting to fairly weigh such benefits would likely entail enormous complexity and matters far beyond our regulatory purview.

64 SDG&E's testimony refers to a study purportedly supporting this claim, but SDG&E did not introduce this study into the record, or state any specifics about the study.

operation of the plant would cause more or less land use impact than a project at an alternative site. In fact, SDG&E introduced testimony establishing that the community surrounding the South Bay units was opposed to a repower as a stand-alone project. Moreover, the land use benefits of using an existing site are already reflected in our method for determining the IDR benchmark. (See Section 6.1.1 below.)

Because SDG&E has failed to show that any aspects of the repower support nondeferrability, it is not necessary to address the remaining two criteria beyond noting that SDG&E's showing is defective in their case as well. Specifically, SDG&E made little effort to quantify the economic and operational benefits of the aspects of the repower, nor did it investigate whether QFs could provide equivalent benefits through use of "adders" and standard offer contracts.[65]

We stress that our rejection of SDG&E's request does not preclude SDG&E from pursuing the repower, either linked with the desalination facility or as a stand-alone project. The CEC in ER-90 found that SDG&E needs 1,292 MW of new generation by 1999. We are designating 473 MW as IDRs in this bidding cycle. That leaves SDG&E with ample additional capacity to fill using its sound discretion.

5.1.2 Heber

Although the Update currently does not permit all-source bidding, we have urged utilities to use the Update to prompt better terms from non-QF sellers. (D.91-06-022, mimeo. p. 82.) SDG&E

65 We note that SDG&E has analyzed a possible voltage support adder, and that the Commission has approved SDG&E's valuation method for this adder. (See D.88-09-026, 29 CPUC 2d 263, 278-79, 289.) SDG&E is silent on whether it has discussed this adder with QFs operating or planning to operate in areas on the SDG&E system where it anticipates need for additional voltage support.

attempted to do so in this phase of the Update by issuing two requests for proposals to establish alternatives for its resource plan and for IDR candidates.[66] These requests allowed independent power producers (IPPs), among others, to submit proposals.

ERCE is an IPP that responded to SDG&E's request for long-term proposals. ERCE proposed to purchase the SDG&E Heber geothermal plant (which SDG&E was planning to retire because of heat supply problems) and to convert it to a gas-fired facility. SDG&E ranked ERCE's proposal in Tier 3 and rejected it. ERCE intervened in the Update to challenge SDG&E's evaluation process. ERCE requests that we reject SDG&E's resource plan or alternatively require SDG&E to revise its evaluation process by using an independent party to evaluate potential IDRs.

SDG&E argues that it properly rejected ERCE's proposal because SDG&E construes D.90-03-060 as barring SDG&E from considering the Heber plant as a potential IDR. SDG&E believes that its litigation with the heat suppliers causes uncertainty over future plant ownership, and that this uncertainty makes ERCE's proposal unsuitable for use as an IDR. SDG&E also notes that the ERCE proposal appeared only marginally cost-effective in the initial cost-effectiveness screening. This screening did not take into account any gas system costs that were SDG&E's responsibility under the proposal.

ERCE does not agree with SDG&E's reading of D.90-03-060. ERCE also maintains that the litigation was in the process of settlement and cites Resolution E-3236 (October 23, 1991), in which this Commission noted that SDG&E had negotiated settlement of the

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66 SDG&E issued requests for proposals up to seven years and for long-term proposals. It received 34 long-term proposals, of which 11 failed the initial cost screening. SDG&E ranked the remaining 23 proposals in three tiers. Tier 1 projects were viable with minor issues, Tier 2 projects seemed viable but had substantial issues, and Tier 3 projects did not appear viable because of issues deemed unlikely to be resolvable.

heat supply litigation. The resolution also authorizes SDG&E to decommission and salvage the plant. ERCE apparently views this as adequate assurance that SDG&E has control over the ultimate distribution of the Heber plant.

The heart of ERCE's objections is its belief that SDG&E has manipulated the screening process to favor SDG&E's internal projects over those of outside suppliers. ERCE believes that if its proposal is not selected as an IDR, it has no means, as an IPP, to compete to fill part of SDG&E's resource need.

We find no basis for granting ERCE the relief it has requested. We make this finding even though we agree with ERCE that D.90-03-060 does not preclude the Heber plant from being an IDR. D.90-03-060 precludes the Heber geothermal return-to-service option as a candidate resource addition (36 CPUC 2d 2, 48) but is silent on alternative uses of the site and assets at the site. However, ERCE has not presented persuasive evidence to show that SDG&E should have ranked its proposal higher. SDG&E's concerns, which are not limited to the ownership issue but include the marginal cost-effectiveness of the proposal and questions regarding gas supply under the proposal, provide a reasonable basis for ranking the proposal in Tier 3.[67]

We also agree with SDG&E that non-QFs, including IPPs, have other ways to deal with SDG&E than by offering up IDRs for QFs to bid against. Between Updates, our utilities will have to decide how to fill undersubscribed IDRs. They also will make short-term

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67 The record does not support ERCE's contention that SDG&E in its analysis of resource options discriminated against IPPs and other utilities, nor does the record suggest that SDG&E singled out ERCE inappropriately. SDG&E assigned 11 of the 23 long-term proposals to Tier 3, but that still leaves 12 proposals in Tiers 1 and 2. Furthermore, our decisions do not require any of the utilities to issue requests for proposals in preparation for the Update. If anything, SDG&E has gone further than either PG&E or Edison to test the waters among potential competitors for filling SDG&E's resource needs.

transactions and even long-term transactions to capture "fleeting opportunities" or to fill long-term need that we did not include in the final Standard Offer 4 auction. This latter category, of needed but not biddable MW, is substantial for SDG&E in this Update.

We commend SDG&E for its use of requests for proposals. We view this use of such requests as an appropriate way to promote competition and develop the best possible package of IDRs, consistent with the current bidding mechanism.

ERCE's challenge also raises a difficult question over how far the Update should go in reviewing utility actions to be taken (or not taken) outside the Update. The capital and running costs used in cost-effectiveness calculations for candidate IDRs are fair game for litigation in the Update, but we are reluctant to hear in the Update questions on utility management decisions that, like SDG&E's handling of Heber and of the requests for proposals, are properly the subject of traditional reasonableness review.

What ultimately happens to the Heber plant is still an open question. SDG&E, even in retiring the plant, has an obligation to its ratepayers to obtain maximum value. If ERCE or any other buyer is willing to pay a reasonable price, a sale would almost surely provide greater benefit to ratepayers than simply scrapping the plant.

5.1.3 NOx Emissions Limit

Another issue concerning residual emissions is DRA's argument that SDG&E included the wrong "cap" on NOx emissions for certain power plants. DRA states that SDG&E erred by using a cap of 0.20 lbs/MWh, when the San Diego APCD anticipates a 0.10 lbs/MWh NOx limit in effect beginning in 1996. SDG&E argues that its cap was proper for a number of reasons. First, SDG&E states its approach is consistent with limitations imposed by the South Coast AQMD, whose minimum level requirement of 0.15 lbs/MWh need not be achieved until 1999. Second, SDG&E argues that the San Diego APCD's proposed numbers are not realistic, and the fact that SDG&E

technically may be unable to comply with the proposed rule could influence the content of the final rule. Third, SDG&E states that it performed a sensitivity analysis using the cap of 0.10 lbs/MWh and indicates that using the lower emissions rate would have little impact on its resource plans.

According to SDG&E, the effect of its using the higher emissions rate appears to be negligible in this Update. However, we agree with DRA that in the next Update, the utility should use the emissions limit of the local air district which is in effect or likely to be in effect during the bulk of the period modeled for cost-effectiveness analysis. If the local air district is contemplating a new limit, the utility should examine if and how that new rate would alter its planning results.

## 5.2 IDRs

### 5.2.1 Geothermal

Geothermal IDRs are cost-effective in all of SDG&E's scenarios. All parties making recommendations identify geothermal IDRs for SDG&E. SDG&E recommends that 100 MW of geothermal be designated as an IDR, while DRA and GRA/IEP both recommend 400 MW and CEERT recommends 500 MW. For the reasons set forth in Section 5 and 5.1, we identify 200 MW of geothermal as IDRs for SDG&E. Half of this capacity is a set-aside pursuant to PU Code Section 701.3.

The parties disagree with SDG&E's geothermal cost data used for its geothermal IDRs. DRA and GRA/IEP both argue that SDG&E's geothermal costs, which SDG&E indicates it got from generic data and data submitted by generic developers, are inadequately

documented. Both DRA and GRA/IEP recommend we adopt geothermal costs similar, but not identical, to those used by Edison.[68]

Also, we note that SDG&E shows different total costs than Edison does, even though similar data should apply to the geothermal technology and known geothermal resource areas (KGRAs) of Southern California. We agree with DRA and GRA/IEP that Edison's method of determining geothermal costs, based on ER-90 data, is better documented on the record than SDG&E's. However, even Edison's costs do not fully comport with ER-90. (See Section 6.2.1 below.) For purposes of preparing a bid solicitation package, we direct both SDG&E and Edison to use the complete set of fixed and variable costs developed by the CEC staff in ER-92 for liquid-dominated flash geothermal technologies.[69]

In its bid solicitation package, SDG&E should specify the KGRA in which its geothermal IDRs would be located. The KGRA should have sufficient resource potential to accommodate SDG&E's IDRs and, in relation to SDG&E's system, should have lower transmission upgrade costs than other KGRAs. This information is necessary in the event transmission considerations are incorporated in this year's auction.

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68 DRA's recommendation differs from Edison's costs in that DRA's proposed geothermal IDR costs do not include imputed fuel costs, but instead include fixed O&M costs. GRA/IEP suggest that Edison's variable O&M costs be split into fixed and variable components. In short, SDG&E, Edison, DRA, and GRA/IEP all agree that a geothermal plant has significant O&M costs. They disagree over the level of those costs (SDG&E uses a lower number than the other three parties) and on the distribution of those costs between fixed and variable components.

69 See Technology Characterization Report, October 11, 1991.

5.2.2 Encina 1 Repower

SDG&E designates the Encina Unit 1 repower as an IDR in its Strategic Preference Plan. We agree and approve this repower (273 MW net) as an IDR for SDG&E.

Although the Encina repower is cost-effective, it is slightly less so than, for example, the South Bay 2 repower. However, SDG&E has strategic reasons to prefer the Encina 1 repower. SDG&E is considering the repower of another of the South Bay units (see Section 5.1.1 above) and believes that the adjacent community would strongly resist the increase in local gas-fired generation associated with development of more than one repower.

SDG&E has given us a fair picture of its resource options as they appeared at the time of the resource plan filings. It has also explained the practical considerations that underlie the selection of IDRs for its preferred plan. We appreciate SDG&E's candor, which inclines us to give weight to SDG&E's judgment on the relative feasibility of these resource options. That judgment provides a reasonable basis for departing from the least-cost ranking derived solely from computer modeling.

We also prefer the Encina repower to the much larger South Bay 3 repower (455 MW net). We have declined to find the latter project nondeferrable (see Section 5.1.1 above); however, making the South Bay 3 repower an IDR would result in a larger total solicitation than we deem appropriate for SDG&E at this time. The Encina 1 repower, in conjunction with the 200 MW of geothermal IDRs we authorize above, results in a reasonable total solicitation that will also help diversify SDG&E's current resource mix.

SDG&E also recognized that, where the selected IDR is slightly higher cost than the ICEM least-cost choice, the benchmark for bidders should be the costs of the strategically chosen IDR. We agree and direct SDG&E to use the Encina 1 repower costs in its solicitation.

6. Edison's Resource Need

Edison's IDRs will total 735 MW.[70] Specifically, we designate as IDRs the Huntington Beach repower (385 MW net), 300 MW of geothermal, and 50 MW (effective capacity) of wind. Half of the geothermal and wind capacity is set aside for renewable bidders, pursuant to PU Code Section 701.3. These IDRs, when taken together with Edison's overall resource additions, form an appropriate resource mix for Edison during this Update cycle. Edison's overall resource additions during the deferral window include 400 MW of spot capacity purchases, close to 3000 MW of uncommitted DSM, and 432 MW of other generation.

In its suggested alternative plan, Edison designated only the Huntington Beach repower and 50 MW of wind as IDRs. (See Sections 6.2.2 and 6.2.3 below.) Edison's resource plan scenarios show wind and repower projects cost-effective as early as 1992 and 1993, respectively. Since Edison's system does not have reliability-based need, we choose the on-line dates of its suggested alternative plan, namely 1997 for the wind IDR and 1998 for the Huntington Beach repower, in order to promote as much competition among QFs as possible.

We also designate 300 MW of geothermal as an IDR. Edison's scenario found geothermal to be cost-effective as early as 1992. In order to avoid lumpiness problems, 1997 will be the on-line date for 100 MW of the geothermal and 1999 will be the on-line date for 200 MW.

The result we reach today is consistent with ER-90. The CEC finds Edison needs 1,167 MW of new generation by 1999, of which 760 MW are categorized "acquire now," with the remaining 407 MW

70 See Figures 3 and 6, following page 3 above, for a summary of the parties' positions on IDRs for Edison and the on-line dates we approve.

deferred to ER-92. Our decision results in QFs bidding for most of the total MW that ER-90 recommends Edison "acquire now."

Our decision falls between the parties' recommendations. Edison appears to recommend no solicitation at all but would agree to IDRs totalling 435 MW under its suggested alternative plan.[71] GRA/IEP and DRA recommend 1159 MW and 1000 MW respectively, and CEERT recommends 1200 MW be designated as deferrable capacity.

We base our decision on maintaining a balance of objectives and consistency with ER-90. The IDRs we designate today equal about 16% of Edison's resource need. Edison's base case resource plan relies heavily on uncommitted DSM, which meets about 65% of Edison's need during the deferral window. Our decision is in keeping with a sound portfolio strategy for Edison, and will reduce the risks of relying on one type of resource to meet such a large percentage of new need.

When Edison's all-DSM plan is rejected (see Section 6.1 below), and Edison's suggested alternative plan is understood, Edison's overall perception of need is quite similar to our own. Edison's alternative recommends 709 MW of new generation, about the same as our result (735 MW). The chief distinction between Edison's recommendations and today's decision is that Edison's plan is too lean on renewables and designates the San Bernardino repower (274 MW net) as nondeferrable.

Since Edison's system is overwhelmingly fossil-fueled, we choose renewable IDRs for almost half of the solicited capacity.[72] Half (175 MW) of the total renewable IDR capacity is designated as

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71 Judging from Edison's comments on the Proposed Decision, Edison now disavows its suggested alternative plan altogether.

72 This is a modest level of renewables. We note that under the Nevada scenario (in which lower emissions costs are imputed to plants in attainment areas), over 1000 MW of renewables are cost-effective for Edison's system over the next eight years.

a set-aside pursuant to the legislative requirement. ER-90 recommends Edison acquire 380-600 MW of renewables now. If we assume that most of the winning bidders against the renewable IDRs are themselves renewables,[73] the auction results should reach the low end of the ER-90 target for renewables.

6.1 Critique of Edison's Resource Plan Analysis

If Edison's "suggested alternative resource plan" is truly its preference,[74] then Edison, as we demonstrated in the preceding section, should find little to disagree with in today's decision on IDRs. But for reasons that are not clear, Edison manufactures two alternative plans which it uses to magnify its differences with this Commission.

For example, Edison represents that the "Base Case Resource Plan (i.e., CPUC Base Case) results in a need for new capacity of 2,100 MW...." (Exhibit 316, p. 2-1.) This is wrong. The ICEM computer analysis using these assumptions (mostly ER-90 plus uniform emissions values from D.91-06-022) shows a very large resource need, but the Base Case Resource Plan required by D.91-06-022 must be one that comports with our requirement of consistency with the CEC's integrated assessment of need.[75] The ER-90 need assessment for Edison indicates Edison should acquire 760 MW during this Update cycle. The "CPUC Base Case" that Edison attacks is neither required nor approved by our resource procurement decisions.

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73 This is a reasonable assumption because fossil-fired bidders would either face large subtractors from their energy price or have to acquire sufficient offsets to avoid the subtractors.

74 Edison so indicates in Exhibit 316.

75 There are other strict requirements applicable to resource plan analysis in the Update, e.g., compliance with emissions limitations set by the air quality district(s) having jurisdiction over the respondent utility.

At the other extreme is Edison's All-DSM Resource Plan. This plan, as the name suggests, involves no new power plant construction at all. Edison says in its Concurrent Brief (at volume I, page 4, emphasis added) that, "from a ratepayer perspective, the Commission should not put any resources out for bid. If Edison had unfettered discretion, it would put no resources out for bid." And two pages later: "Edison's ratepayers would be better off from a cost perspective if no new powerplants were put out to bid in this Biennial Update. Edison would not be opposed to such a Commission decision."

The conclusion is inescapable that Edison's "preferred" strategy is in fact the All-DSM Plan. Curiously, Edison chose not to support this strategy in its testimony despite this Commission's repeated invitation to Edison and the other respondents to include in their resource plan showings a description and justification of precisely what they would do in their "unfettered discretion."

This Commission vigorously supports DSM programs, but there are many other resource options and planning objectives to be considered. We are frankly skeptical that any reasonable analysis could weigh (among others) DSM, plant modernization (e.g., repowering), development of alternative and renewable fuel technologies, and power purchase opportunities in regional markets, and reach the conclusion that DSM should exclude all the rest.

The following list sets forth a few of our major concerns about Edison's All-DSM Plan.

1. Not Least-Cost. Edison derives its estimate of cost-effective DSM potential from analytical tools different from those used to test supply-side options. Until the same tools are used for both, there is no assurance that the resulting plan is "least-cost." In fact, the "static" cost-effectiveness tests currently used for DSM by Edison will almost certainly result in a sub-optimal selection, timing, and sequence of resource additions.

2. Premature. In contrast to Edison, SDG&E has shown that ICEM can be adapted to test both generation and DSM resources. Edison is now working on its own integrated planning pilot demonstration. There is no obvious need to drastically increase the DSM level in Edison's resource mix until Edison has performed its integrated planning pilot, the results have been reviewed, and modifications have been made in preparation for use of the integrated planning tool in the next Update cycle. The All-DSM Plan should also await new measurement and evaluation procedures for DSM programs. (These procedures are under development in R.91-08-003/I.91-08-002.)

3. Unprecedented and Implausible. The CEC, CPUC, and utilities have investigated DSM potential on an ongoing basis for years. Absent dramatic technical advances, it is reasonable to assume that current projections of DSM potential already account for the large majority of practicable cost-effective opportunities for utility DSM programs. Edison's All-DSM Plan, however, assumes almost twice as much DSM as ER-90, which already relies on uncommitted DSM to meet about 2/3 of Edison's resource need through 1999.[76] This sudden discovery of untapped DSM potential has undergone scant review and appears to rely on highly optimistic assumptions concerning both energy savings and market penetration.

4. Inconsistent with ER-90. ER-90 supply and demand projections form the base case in the Update. While the CPUC allows the parties to run sensitivities around those projections, Edison has failed to run any sensitivity assuming less DSM than in ER-90, so we have only an incomplete record of how different levels

76 We note that Edison apparently took the position before the CEC that the ER-90 DSM forecast is itself too high. (See ER-90 at p. 6-13.)

of DSM affect Edison's system costs or rates, and accordingly no basis for modifying ER-90's need assessment.

5. High Risk. Because the All-DSM Plan would add no generation resources, Edison essentially counts on all the projected DSM actually materializing. This is unrealistic for any category of resource. Edison also proposes such exclusive reliance despite the fact that techniques for measuring and evaluating the success of conservation programs are still evolving. The record in the Update shows that the target savings in many such programs either do not materialize or do not persist.

6. Bad Investment Strategy. The CEC and the CPUC have both stressed diversity as a means to hedge against reliability and price risks in electric resource procurement. This emphasis is consistent with modern investment theory. In contrast, Edison's All-DSM Plan by definition excludes all other long-term investment options.

7. Inconsistent with Edison's Announced Objectives. Edison does not square its All-DSM Plan with planning objectives used to justify its recommendation not to add QF resources. For example, Edison stresses the need for load-following resources on its system. Yet many DSM programs (perhaps most) have no ability to follow load. Baseloaded conservation prevents purchases of economy energy and exacerbates minimum load problems to the same extent as baseloaded generation. In contrast, final Standard Offer 4 provides the utility substantial ability to curtail QF output at the utility's discretion. By ignoring this difference in its All-DSM Plan, Edison is applying one set of criteria for its own earnings opportunities and another set for the competition.

Another important example is Edison's use of the reliability criterion. Edison would add generation resources only when required to meet its reliability standard. In contrast, Edison would pursue all DSM programs (not just opportunities that would otherwise be lost) regardless of whether its system showed a need for more resources in a given year.

8. Neglect of Major Planning Goals. Edison's All-DSM Plan elevates one worthwhile goal--the capture of conservation opportunities--to absolute supremacy, while neglecting all others, including many that the CEC and the CPUC have endorsed, and many that are embodied in statute. For example:

- The plan does not encourage the development of independent sources of electric energy (see PU Code Section 2801).
- It does not value the resource diversity provided by renewable resources (see PU Code Section 701.4) or reserve any portion of need for such resources. (See PU Code Section 701.3.)
- It fails to modernize, through repowering or retirement, Edison's 10,000+ MW of aging gas-fired facilities. This failure will require Edison to shut down many older plants or spend more money on emission control retrofits in order to comply with the South Coast AQMD retrofit rule. There is no showing that this potential increase in capital expenditures for retrofits results in an optimal resource plan, nor is it clear that the All-DSM Plan even accounts for that increase.
- It does not demonstrate optimization among the various goals (cost minimization, energy efficiency, environmental improvement, reliability,

resource diversity, development of renewables) specified in PU Code Section 701.1.

- The plan does not consider short-term and long-term power purchase opportunities in regional markets.

9. Inappropriate Risk Allocation. Edison is protected by our fuel cost balancing account (ECAC) from almost all risk related to fuel price variation. I.e., if its costs are higher than predicted, the increased costs, with interest, are recorded in the balancing account and the balance amortized periodically through rates adjusted in ECAC proceedings. Risks are approximately symmetrical because the ECAC also results in lower rates when fuel costs decline. But as Edison relies on unprecedented amounts of DSM in its resource plan, the risk of such reliance (that Edison will incur higher costs of generation and purchased power if the desired DSM savings do not materialize) falls almost 100% on ratepayers. Before an All-DSM Plan is adopted, the current regulatory allocation of fuel price risk must be reconsidered and possibly changed. Edison does not analyze or even acknowledge these possible implications for risk allocation.

10. Unaccounted-for Costs. Edison compares only the capital costs of various resource plans. Edison's rates, however, reflect not only capital costs but also items that are expensed, such as fuel costs and most DSM expenditures. Furthermore, some of Edison's DSM programs require ratepayer expenditures (e.g., purchase of new appliances) in addition to expenses reflected in rates. To compare the ratepayer impacts of different resource procurement strategies, both capital and expense items must be accounted for, and all impacts must be considered. Focusing on only some of these categories presents an incomplete and potentially misleading picture.

We emphasize that the above list is not a criticism of DSM, nor is it a criticism of innovative resource planning. What

we are pointing out is that Edison has failed to make its case. In future Updates, we hope Edison will provide the kind of frank and far-ranging discussion of strategic preferences that we find in this record from SDG&E.

Edison's comments on the Proposed Decision and statements at the en banc hearing strongly confirm our finding that by far the most expensive strategy is to do nothing. Running Edison's existing system would cost ratepayers billions of dollars. Edison has economic need for large amounts of new resources. DSM can meet much of that need, but we would merely be repeating past planning errors if we relied on a single category of resource to meet all of those needs.

Edison now argues that the solicitation should be delayed. As we have just discussed, delay is the most expensive strategy. Edison has to make a series of interrelated decisions now regarding DSM programs, repowering, compliance strategy with South Coast AQMD retrofit rules, and so on. Bidding in this solicitation will also involve transmission service, which in turn will require the utilities to make assumptions about the loads and resources on their systems. We can see no good and much harm in keeping these matters in suspense for an indefinite period. The solicitation should go forward this year.

6.1.1 San Bernardino Repower

Edison seeks a determination of nondeferrability for the repower of San Bernardino Units 1 and 2. These are gas-fired facilities. The proposed repower would increase the existing capacity by 274 MW, from 126 to 400 MW.

The Commission's nondeferrability test for specific projects is set forth in D.86-07-004 and discussed in Section 5.1.1 above. Edison argues that the project is cost-effective, will provide operational flexibility and efficiency for Edison's system, provides economic and land use benefits associated with an existing

site, will use less water than many other types of generation, and will provide emission reduction benefits.[77]

GRA/IEP and DRA argue that Edison has not met our nondeferrability test. GRA/IEP and DRA generally do not contest the cost-effectiveness of the proposed repower.[78] However, both argue that the repower does not satisfy the other three criteria in our nondeferrability test. We agree with GRA/IEP and DRA that the San Bernardino repower fails that test.

The aspects of the repower that Edison claims justify nondeferrability are not shown to be unique or impossible for QFs to provide. Edison proposes that its Huntington Beach repower be

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77 Edison's witness stated on cross-examination that Edison believes repowers are generically nondeferrable, at least where there is no system-wide increase in capacity. We disagree. In D.86-07-004, we rejected proposals to establish "broad categories of generically nondeferrable resources." (21 CPUC 2d 340, 380.) We have made narrow exceptions to this rule (e.g., hydro license renewals) and find no persuasive reason to expand the list. The CEC has declined to consider repowers generically nondeferrable, and we reaffirm our holding in D.86-07-004.

We also note that the category of <u>deferrable</u> resources includes "expansion...of an existing resource." (D.91-03-058, mimeo. p. 9.) The repower would more than triple the capacity of these San Bernardino units. The fact that Edison would retire a like amount of capacity elsewhere on its system does not change the effect of the repower on the San Bernardino plant. Utilities commonly accompany the addition of new capacity with retirement of aging plants. We fail to see why Edison's intentions regarding retirement of other plants have any relevance to whether competitors should be allowed to bid against the cost of the proposed repower.

73 DRA does question the way Edison conducted its cost-effectiveness analysis. Specifically, DRA argues Edison did not include the total offset costs of the project. This happens, according to DRA, because Edison obtains offsets for the repower by retiring other Edison plants without recognizing the value of the offsets so consumed as a cost of the repower. We agree with DRA. (See Section 3.1.3.)

deferrable by QFs, yet fails to elucidate any aspect of the San Bernardino repower that convincingly distinguishes the one repower from the other. For example, Edison argues that the San Bernardino repower is needed to provide Edison with operational flexibility.[79] Yet flexibility is not unique to this repower or to utility plants, as the Edison witness conceded. He also noted that this repower's "inability to be used for ramping and regulation control would not be a benefit." (RT 3393.)

Edison's arguments regarding use of an existing site parallel SDG&E's and fail for the same reasons. (See Section 5.1.1 above.) We acknowledge the economic benefits to using existing equipment and interconnection at an already developed site, but the final Standard Offer 4 procedure captures these benefits. In other words, the low cost of the repowering at an existing site is reflected in the IDR's lower costs compared to other resource options, and it is these lower costs that become the benchmark against which a QF bids.

Edison also argues that a finding of nondeferrability is justified because the San Bernardino repower will use less water than many other types of generation. Yet, Edison's own testimony establishes that both geothermal and wind resources can require less fresh water per MW-hour than a repower does.

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79 Edison states that operating flexibility considerations are one of the key reasons that we have considered peakers, such as combustion turbines, to be nondeferrable. In D.87-11-024, 26 CPUC 2d 62, 72, we reaffirmed that "our main reason for considering peakers nondeferrable by QFs is that such plants typically have no energy-related capital costs." (Id., emphasis added.) We also noted that our experience with negotiated curtailment and dispatchability agreements between QFs and utilities confirmed "our belief that the absence of energy-related capital costs, and not the complexity of devising appropriate contractual operating terms, dictates our decision not to authorize a peaker-based long-run standard offer." (Id.)

Finally, Edison generally argues that the repower will improve in-basin emissions by the installation of new emissions control technology, and will allow Edison to monitor this new technology to ascertain whether its benefits justify future use in other plants. Other than general statements, Edison does not demonstrate the repower's role in its air quality program, or whether the use of this technology elsewhere would enable it to gain the needed information. Thus, Edison has not met its burden of proof on this issue.

No detailed discussion of other criteria is necessary. Edison's attempts to quantify economic and operational benefits are perfunctory, and it fails to explore the availability of such benefits through "adders" and standard offer contracts.

## 6.2 IDRs

### 6.2.1 Geothermal

Geothermal IDRs are highly cost-effective in Edison's base case (1200 MW as early as 1992). Using the Nevada residual emissions values for plants in attainment areas, 1100 MW of geothermal are cost-effective over the next eight years. GRA/IEP and CEERT each recommend 400 MW, while DRA recommends 626 MW of geothermal.

For the reasons discussed in Sections 6 and 6.1 above, we designate 300 MW of geothermal IDRs for Edison. Half of this capacity is set aside pursuant to PU Code Section 701.3.

GRA/IEP question Edison's division between fixed and variable components of geothermal costs for these IDRs. GRA/IEP endorse SDG&E's number for variable O&M cost, and they would deduct that number from Edison's total O&M to derive a cost for fixed O&M.

Edison testified that it used geothermal cost data from ER-90, and that ER-90 did not use a fixed O&M component. However, our review of ER-90 and its supporting documentation indicates the CEC developed both fixed and variable geothermal O&M costs. For

purposes of preparing a bid solicitation package, Edison should use the same geothermal costs we determined appropriate for SDG&E.[80]

Also, Edison should specify in its bid package the KGRA in which its geothermal IDRs would be located. (See Section 5.2.1 above.)

6.2.2 Wind

There is relatively little controversy regarding a wind IDR for Edison. Edison recommends 50 MW of wind in its suggested alternative resource plan. DRA, CEERT and GRA/IEP each recommend 100 MW of wind. A wind resource is cost-effective for Edison as early as 1992, and is found to be cost-effective in virtually all the scenarios Edison presented. As discussed in Sections 6 and 6.1 above, we designate a 50 MW wind IDR for Edison, with a 25 MW set-aside for renewables pursuant to the legislative set-aside requirement.

GRA/IEP advocate that the costs of the wind IDR should be the average of Edison's estimated costs for San Gorgonio and Tehachapi wind generation. (See Exhibit 309, pp. 5-3, 5-4.) We disagree. Because we anticipate specific transmission cost considerations to be part of this bidding cycle, it is important for the utility to designate at least the general location of each IDR. In this case, the wind IDR should be set in the location most beneficial to the Edison system. According to Edison, the capital and O&M costs are the same for both sites, but the transmission line and substation upgrade costs at San Gorgonio are lower.

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80 Specifically, Edison should use the complete set of fixed and variable costs developed by the CEC staff in ER-92 for liquid-dominated flash geothermal technologies. See Technology Characterization Report, October 11, 1991.

Therefore, Edison should base its wind IDR price on the San Gorgonio costs.[81]

6.2.3 Huntington Beach 3 Repower

Edison designates the Huntington Beach Unit 3 repower as an IDR in its suggested alternative plan. We agree and approve this repower (385 MW net) as an IDR.

The Huntington Beach repower was found cost-effective in many of Edison's scenarios. GRA/IEP also recommend this repower as an IDR. In ER-90, the CEC offers a similar recommendation.

Although the repower of Huntington Beach Unit 3 is cost-effective, it is slightly less so than, for example, the repower of San Bernardino Units 1 and 2. However, we prefer the larger size of the Huntington Beach repower to the smaller (274 MW net) San Bernardino repower. This IDR, 300 MW of geothermal, and 50 MW of wind, result in a reasonable total solicitation for Edison.

Edison's comments on the Proposed Decision indicate that, given our rejection of its request for a finding of nondeferrability for the San Bernardino repower, it would prefer we designate the latter as an IDR. We affirm the Proposed Decision.

First, the CEC found that Huntington Beach 3 should be repowered as early as 1996. While the CEC mentions the repower of three other units and selective catalytic reduction retrofits at various other units, the San Bernardino repower is nowhere

81 We earlier directed PG&E to use a generic capacity factor in establishing its wind IDR (see Section 4.2.1 above), while we here direct Edison to use site-specific considerations for estimating transmission upgrade costs associated with its wind IDR. The difference arises because all of the respondent utilities use generic gross-to-effective capacity conversion factors for as-available technologies like wind. This is appropriate given the nature of as-available resources. In contrast, as we made clear in I.90-09-050, we favor a site-specific approach for the transmission upgrade costs of IDRs and QFs competing against them.

mentioned in the CEC's need assessment for Edison. (See ER-90 at pp. 6-12, -13.) Edison should present its case regarding the San Bernardino repower in ER-92.

Second, in view of the fact that the Huntington Beach 3 and the San Bernardino repowers are both cost-effective, it makes economic sense to seek to "defer" first through bidding the more costly of the projects. If Edison believes it must, for whatever reason, commit to the San Bernardino repower before the next Update, it has room to do so even if all IDRs are fully subscribed.

The benchmark price of the Huntington Beach repower IDR should be the costs of this strategically chosen IDR, and not the ICEM least-cost choice. (Cf. Section 5.2.2 above.) Edison should also correct both the repower IDR's capital costs to include the full offset costs (see Section 3.1.3.1 above), should ensure the repower's residual emissions calculations are consistent with our determination in Section 3.1.3.2 above, and should recalculate the offset costs consistent with Section 3.1.3.3 above.

## 7. Pending Motions and Requests

A few motions and requests, generally dealing with procedural matters, are pending. With the exception of SDG&E's request for official notice, they are minor and, to the extent they are not disposed of elsewhere in today's decision, we deny them without comment.[82]

On December 18, 1991, SDG&E requested this Commission officially notice a new gas price forecast adopted on November 6, 1991, by the CEC. The forecast is lower than that used in ER-90 and the utilities' base case filings here. SDG&E believes the

82 On October 3, 1991, Edison filed its "Request...to Consider the Overall Impact of the Commission's Resource Planning Decisions." Our analysis of Edison's showing in this phase of the Update (see Sections 3.1 and 6.1 above) adequately responds to this request.

forecast lends authoritative support to its position that the possibility of lower than anticipated fuel prices constitutes a major risk, one which resource planners should hedge against in this ER/Update cycle. The CEC supports SDG&E's request, which we grant. (See Section 9.1 below.) The new forecast, which is part of the CEC's preparation of ER-92, will be used in evaluating bids in the auction to be conducted pursuant to today's decision.

## 8. Remaining Tasks for this Update Cycle

### 8.1 Changes from D.91-06-022 and I.90-09-050

Before opening the solicitation, we will hold hearings regarding changes to the contract and to auction protocol that were necessitated by the changes we made to final Standard Offer 4 in D.91-06-022.[83] We anticipate holding these hearings in March 1992, and issuing a decision soon thereafter.

As we discussed in Section 3.3 above, we also have issued a transmission access investigation (I.90-09-050), which is closely linked with this proceeding. We reaffirm our desire to make substantial progress in that investigation within the current Update cycle, so that weighing of transmission costs as part of total costs, together with reasonable access to wheeling service, could be included in this year's solicitation.

We have issued an interim opinion in that investigation, with policy direction on key transmission issues. (See D.91-10-048.) We have also held a negotiating conference in order for the parties to narrow the issues and develop a consensus

83 Many parties have participated in workshops on these issues since shortly after D.91-06-022 was issued. We understand that some of the parties have reached proposed stipulations or settlements on a number of issues, although some issues still remain for hearing.

approach as far as possible.[84] We anticipate holding hearings this spring, and issuing a decision soon thereafter. It is possible that the latter decision will also entail changes to the final Standard Offer 4 contract, in which case the assigned ALJs should ensure that these are incorporated in the contract as expeditiously as possible.

8.2 The Auction

This is the first time that the utilities will issue solicitation packages for final Standard Offer 4. We believe it is prudent to develop some procedure by which the parties can preliminarily review the solicitation packages in order to prevent delay or confusion that could result from typographical errors, omissions, or other problems with the packages turning up after the utilities have published them. The assigned ALJs should promptly schedule a workshop or prehearing conference to consider the appropriate method, scope, and timing of a pre-publication review of the utilities' solicitation packages.

The number, timing, and specific attributes of the IDRs that we designate in this decision raise some bidding and scoring issues.[85] The auction resulting from today's decision will be held with multiple IDRs and several different on-line dates for each utility. The process is complicated further by a set-aside requirement for each utility. Individual transmission costs and residual emissions evaluation may also be factors in each bid. We

84 From December 16-20, 1991, and from January 13-24, 1992, the parties successfully negotiated a series of agreements in principle and narrowed the range of issues to be resolved in contested hearings.

85 We do not intend by this discussion to revisit previously decided bidding and scoring issues, such as the second-price auction.

want to ensure that the bidding and scoring rules result in an optimal group of winners in each auction.

For example, given the on-line date, emissions, and transmission cost characteristics specified for each IDR, it would be difficult for a QF to submit a single bid against all a utility's IDRs. But if a QF could only compete against a single IDR, there is a chance that some "losers" on one IDR would have won had they been allowed to also submit a bid specific to one of the other IDRs of the same utility.

Since this is our first auction, a good case could be made for conducting the simplest possible auction in this Update cycle. This would mean that a QF would have to choose which of several IDRs to bid against.

Such a limitation on bidding, as we have noted, might not yield the best group of winners. There is a significant danger of a poor outcome because of the possibility of each QF "gaming" the auction by choosing to bid against the IDR that would give it the highest economic rents, while lower price IDRs that QFs might still be able to beat might go under-subscribed.

There are probably many approaches by which to resolve these bidding and scoring issues. One such approach, in the form of a proposal in order to stimulate further discussion, is set forth in Attachment 6 to this decision. The assigned ALJs should request the parties' views on whether this approach, or some other suggestion, is desirable or feasible in this Update cycle as an alternative to a simple one bid per QF per IDR approach. If not, then the solicitation should proceed under the latter approach.

We note that a recent ALJ ruling[86] directs the parties to serve testimony regarding (1) a proposed settlement on final Standard Offer 4 contract modifications, and (2) unresolved issues regarding sales by QFs to multiple entities, terms for as-available sales in excess of firm commitment, and aggregation of IDRs for bidding purposes. We agree that consideration of the latter three issues is timely. The circumstances of this solicitation, with multiple IDRs for all three utilities, makes the aggregation issue an important one. Moreover, developments in our transmission access investigation open the possibility of QFs becoming active sellers in the short-term wholesale electricity market. That possibility should be explored. In many ways, it would fulfill one of our major goals when we embarked on our QF program. With reasonable assurance of transmission access and the ability to make long-term and short-term sales, QFs would be able to compete fairly with utilities and IPPs, and we could proceed quickly to lift the current QFs-only limitation in our bidding process.

8.3 Methodology Phase

Each Update provides a forum for considering changes in methodology for all of our standard offers. Our original schedule for this Update establishes Phase 3 as the methodology phase.[87]

To date, we have had concurrent activity in the resource plan phase and Phase 3 on selected issues. (See, e.g., D.91-11-022.) We will continue concurrent activity in Phase 3; however, our review of methodological issues will be limited. In

86 ALJ's Ruling (February 6, 1992) Scheduling Service of Testimony and Hearing on Modification of Final Standard Offer 4 Contract to Implement Decision 91-06-022.

87 This phase would also address things like costing periods for time-differentiated prices, to the extent that these are in need of revision. (See generally D.88-03-026, 27 CPUC 2d 502.)

particular, no matter resolved in D.91-06-022 or in today's decision is subject to reconsideration in Phase 3.[88]

Consultation with the parties is appropriate to schedule and coordinate activity in Phase 3. The assigned ALJs should schedule a prehearing conference for this purpose. Since our review of methodological issues will be limited, any party proposing an issue for Phase 3 must justify inclusion of that issue and state specific reasons for its timeliness and relative importance.

A common deficiency of the utility showings in this phase was, surprisingly, the analysis of ratepayer impacts of the different resource plans presented. Edison, for example, made broad assertions about its All-DSM plan and has a comparison of revenue requirements it asserts would result from different plans, but it does not set forth its methods or assumptions for these revenue requirement calculations, and its cost data for the All-DSM plan concededly omit whole categories of expense.

We need better analysis of ratepayer impacts, with all assumptions and methods clearly stated. We direct the Commission Advisory and Compliance Division (CACD) to develop, before the next Update cycle starts, a common format for use in ratepayer impact exhibits. CACD should consult with the utility respondents and other parties, and may hold one or more workshops for this purpose.

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88 An exception can be made where the final Standard Offer 4 contract must be changed to incorporate results from the transmission access investigation.

9. Comments on Proposed Decision

Pursuant to PU Code § 311 and our Rules of Practice and Procedure, the Proposed Decision of ALJs Kotz and Econome was published on February 24, 1992; parties then had an opportunity to file comments and replies.[89] We also convened a hearing en banc on March 31, 1992. Parties were invited to file position statements on the Proposed Decision and also issues statements addressing three topics (ratepayer impacts, fuel price forecasts, and residual emission costs) specified in Assigned Commissioner Fessler's Ruling of March 24, 1992. These topics formed the basis of panels at the hearing.[90]

We have examined this large body of oral and written comment from a number of perspectives. Not the least important has been our appreciation of the economic recession which currently plagues our state and of concerns over the competitiveness of that economy. While we affirm the Proposed Decision in many respects (notably, the determinations on the type, size, and timing of IDRs), we have made several significant changes designed to reduce

89 We received comments from PG&E, SDG&E, Edison, DRA, GRA/IEP, CEERT, U.S. Windpower, and SoCalGas. All except DRA and SoCalGas also filed reply comments.

90 We received position statements and statements on one or more of the specified topics from PG&E, SDG&E, Edison, DRA, CEC, CEERT, GRA/IEP, and Gas Cogeneration Working Group. We also received statements from San Diego APCD, South Coast AQMD, Natural Resources Defense Council, Texaco Syngas Inc., BHP Minerals International Inc., Chevron U.S.A. Production Company, American Wind Energy Association, and SoCalGas.

The following parties provided panelists and offered closing statements at the en banc hearing: PG&E, SDG&E, Edison, DRA, CEC, South Coast AQMD, CEERT, GRA/IEP, Gas Cogeneration Working group, and Natural Resources Defense Council. The various written statements for the hearing as well as the transcript of the hearing itself are part of the record of this proceeding.

the burden of high energy costs to all classes of California ratepayers. These changes affect the benchmark price against which QFs bid, the evaluation of bids, and the calculation of adder/subtractor payments related to residual emissions. We summarize the most significant changes below.[91]

9.1 ER-92 Gas Price Forecast

We accept CEC's recommendation that its gas price forecast adopted November 6, 1991, for use in ER-92, also be used in evaluating bids in the auction that will be conducted pursuant to today's decision.[92] For the purposes of consistency, we will also assess the cost-effectiveness of DSM programs utilizing the ER-92 gas price forecast. We do not redo our need analysis, however. That analysis already addresses fuel price uncertainty, and the ER-92 gas price is within the range of prices we have considered.

We would prefer not to use one gas price forecast for our base case planning analysis and a different forecast in the acquisition portion of resource procurement. That result is dictated, however, by the unfortunate lag that has occurred between the adoption of the gas price forecast underlying ER-90, the adoption of ER-90 itself, and our translation of ER-90 into a set of long-run marginal costs and bidding benchmarks.

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91 We have also made other changes to the Proposed Decision to improve the discussion, respond to a motion for consolidation (see Section 3.2.3 above), add references to the record, and correct typographical errors.

92 This forecast is about 7% lower in 1999 than the forecast used in ER-90, according to the CEC panelist Chandley at the en banc hearing. (RT 5170.) The lower forecast, other things being equal, would tend to favor gas-fired QFs in the bid evaluation, because the fuel savings offered by QFs with low variable costs would appear lower than if a high gas price forecast were used.

We agree with CEC that we must explore ways to shorten this lag. Our concern is not so much with the bidding benchmark becoming out-of-date--there is every indication that competition will be vigorous and that bids will accurately reflect current cost expectations. We are greatly concerned, however, at the prospect that the winners from a solicitation based on one ER would have an "economic need" test applied at the CEC based on a later ER. If that were deemed necessary or appropriate, one of the fundamental goals of coordination between the two agencies would be frustrated.

9.2 Nonuniform Valuation of Residual Emissions

In D.91-06-022, we directed that the utilities' base case planning analysis assign a uniform value to residual emissions, regardless of where they occurred, based on the purchasing utility's marginal cost of emission control. We also required an alternative planning scenario, under which the value assigned to residual emissions varied, depending on where those emissions were generated. Emissions occurring in nonattainment areas were still to be valued using the purchasing utility's marginal cost of control, but emissions occurring in attainment areas were assigned values adopted by the Nevada Public Service Commission.

Based on the record in this phase, we determine that the methodology embodied in the alternative scenario is more appropriate for California than is uniform valuation. The alternative methodology should henceforth be used for the base case analysis in our proceedings for electric resource planning and acquisition.

We acknowledge there are strong arguments for the methodology (i.e., uniform valuation) we are rejecting. For example, it is similar to the avoided cost principles we have consistently applied in developing the market for alternative and renewable energy. We are not, however, dealing with a cost here but an externality. We question the appropriateness of rigorously

applying market theory in a situation where (unlike wholesale electricity sales) the market is nascent or nonexistent.

We are aware that other jurisdictions addressing residual emissions valuation have generally adopted uniform values.[93] We understand their reasons for doing so, but we think few jurisdictions have situations comparable to California's, where the state and regional picture presents such drastic air quality differentials.

The Proposed Decision strongly endorsed uniform valuation but properly declined to endorse the level of new capital investment that such valuation implied. In effect, uniform valuation was endorsed, while nonuniform valuation was implemented. We think clarity and understanding will both benefit from unambiguously approving nonuniform valuation as part of the planning base case.[94]

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93 Bonneville Power Administration is an exception. It applies different values, depending on whether the generation source is West or East of the Cascades. The CEC to date has also endorsed valuation based on at least regional distinctions.

94 We are satisfied that the nonuniform valuation of residual emissions is the correct methodology. However, as with other planning input assumptions, the Commission has benefited from the parties' analyses of alternative scenarios. In the instant case, these alternative scenarios illuminated the potential

(Footnote continues on next page)

This change in methodology should also be reflected in the final Standard Offer 4 payment structure. Specifically, the emissions rate of the winning QF (measured per unit of generation output) will still be compared with that projected for the IDR, but any adder (or subtractor) will be computed using the emission value for the QF's generation site.

9.3 Cost of Offsets

We affirm the Proposed Decision in valuing offsets at the purchaser's marginal cost of control. However, we prefer DRA's method of calculating the one-time payment of that cost to the utilities' methods, which result in a significantly higher payment and correspondingly higher bidding benchmark for those IDRs (i.e., the repowers) for which offsets would be required. (See Section 3.1.3.3 above.) The effect of this change is to increase the difficulty for QFs to underbid repower IDRs.

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(Footnote continued from previous page)

effect on ratepayers of various planning assumptions, including the values applied to residual emissions. Such information will continue to be useful in future resource planning proceedings. Therefore, we direct the utilities to present alternative planning scenarios in future Updates. A private cost scenario (with emissions valued at zero) provides us with resource plans that meet reliability concerns and demonstrate how utilities would reduce the costs of operating their systems absent our additional objective of reducing the environmental impact of residual emissions. A second scenario valuing residual emissions based on the purchasing utility's marginal cost of emission control provides us with information about the cost of aggressively reducing residual emissions, wherever they occur. Both bound the resource planning spectrum, on the one hand ignoring residual emission impacts, and on the other, taking residual emission valuation to their resource planning extreme. It is within this spectrum that we wish to continue to strike a reasoned, balanced approach to meeting our objective of minimizing the cost to society, including environmental costs, of reliable energy services.

We note with interest the utilities' eagerness to lower the bidding benchmark, use lower gas prices in bid evaluation, and in other ways distinguish (to the bidder's disadvantage) the acquisition inputs of this proceeding from the planning inputs. We strongly endorse consistency in planning and acquisition assumptions, and we have made only a few changes, where the novel issues presented in this Update have required such changes.

We emphatically reject SDG&E's argument that a host of new numbers could be plugged in just before the auction. An auction is a very different situation from the kind of one-on-one negotiations where we have criticized SDG&E on occasion for using outdated assumptions. Moreover, last-minute adjustments could easily serve opportunistic ends, particularly where the utility itself is not accountable for building the IDR at its stated cost. We have so far declined to require such accountability, but utility requests to revise IDR cost estimates after resource need has been determined suggest the accountability issue should be revisited. This can be taken up in Phase 3.

Finally, another matter that should be revisited soon is the role offsets should play in determining the amount of residual emissions from a power plant. In D.91-06-022, we decided that required offsets should be "netted" against a power plant's actual residual emissions. Where jurisdictions require offsets in a ratio greater than 1:1, the "netting" of offsets can result in a fossil-fired plant showing negative emissions and thus appearing cleaner than low-emission or no-emission technologies. This aspect of offset policy was not at issue in the resource plan phase, but we note that our treatment of the effect of offsets in this regard is at odds both with the CEC and with air quality regulators.

Findings of Fact

1. The Update provides an industry-wide forum for continuing our regulatory oversight of utility/QF matters. A major purpose of the Update is to develop current prices for final Standard Offer 4,

our resource plan-based standard offer. This involves quantifying the megawatts (MWs) that QFs can fill on the basis of each utility's need for new capacity. A winning bidder in the auction would still have to undergo appropriate review and obtain all relevant permits from the agencies with siting authority. Each two-year Update cycle commences upon issuance of the CEC's Electricity Report.

2. "Residual emissions" are air pollutants that are released after all mandatory pollution abatement measures have been implemented. Recognizing the environmental costs of residual emissions of different generation resource options affects cost-effectiveness analysis for purposes of resource procurement.

3. Despite the success of the utilities and other sectors of the California economy in preventing further environmental degradation, these efforts did not achieve the significant improvements in air quality necessary to satisfy state and federal clean air standards.

4. Air quality regulators have developed a variety of programs and measures from which the costs of clean-up can be calculated. Both the CEC and this Commission have determined that such costs should be factored into the process by which electric utilities plan for resource additions. The effect of this determination is to assign for the first time a monetary value to the residual emissions of power plants.

5. Traditional resource planning objectives, such as reasonable rates and reliable service for all ratepayers, are equally important objectives to be considered along with improving air quality.

6. Edison's and SDG&E's analyses both indicate that Edison and SDG&E need to change their resource mix substantially to reduce emissions.

7. At this time, the Commission does not have an explicit value for fuel diversity, since residual emission valuation by

itself was sufficient to cause diverse technologies to appear in the base case resource plans.

8. Coal plants generally emit large quantities of carbon and SOx. These pollutants raise concerns about potential impacts, e.g., climate change and acid rain, that cross state and even national boundaries.

9. The extent of the climate change problem and national policy on climate change remain uncertain at this time.

10. Choices for long-term resources go to the heart of this planning process. These choices are ones that ratepayers will live with for 20 years, 30 years, perhaps longer.

11. Offsets already owned and exemptions from offset requirements are both assets that may be consumed in a repower project and thus have a value equal to the cost of a corresponding amount of offsets acquired in the open market.

12. An exemption from needing to obtain an offset is not equivalent to an offset for purposes of calculating residual emissions.

13. DRA's method for calculating offset costs is reasonable. DRA follows the South Coast AQMD's approach for developing maximum cost of controls required to generate offsets. This method yields a lower offset cost than the utilities' method while recognizing that offsets are likely to become scarce.

14. After recognizing air quality impacts in our planning goals for electric utilities, probably the single most important resource planning task facing this Commission and the CEC is improving our capability to evaluate DSM and to directly compare DSM resources with supply-side resources.

15. The use of different planning tools makes it difficult to ensure that the final resource plans result in an optimal mix of generation and DSM.

16. In its Update analysis, SDG&E shows about twice the ER-90 level of uncommitted DSM, amounting to about 30% of SDG&E's

resource need over the next eight years. The parties agree, subject to some general reservations about DSM forecasting, that SDG&E's levels of uncommitted DSM are reasonable:

17. The resource plan phase of the Update is too compressed a review for us to say that SDG&E's "integrated planning method" is now perfected.

18. Given the large amount of DSM in current utility resource plans, it is legitimate to consider the uncertainty of DSM forecasts in the resource planning process.

19. Our bidding process needs refinement to allow direct comparison of an IDR's transmission costs with the transmission costs of the bidding QFs.

20. The Update process is designed to deal with many variables and many policy goals, some of which may conflict with each other.

21. All parties agree with the principles that no forecast of future conditions is perfect, and that every resource plan will contain tradeoffs.

22. Modern resource planning is a combination of computer analysis and expert judgment.

23. This Commission has always insisted that each utility's resource plan testimony explain how the utility is responding to uncertainty and incorporating strategic preferences in its plan.

24. Strategic preferences do not strongly affect the PG&E resource plan at this time. Strategic preferences are vital for SDG&E and Edison because the recognition of residual emissions costs shows that these utilities need to change the resource mix on their systems.

25. Short-term purchases (purchases of five years of less) help an electric utility smooth its supply curve, maintain prudent reserves, and maximize its ability to participate in inter-regional wholesale markets.

26. Edison and SDG&E need to modernize, diversify, and clean up their present mix of power plants.

27. Short-term purchases do not themselves accomplish needed changes to the utility infrastructure. Too much reliance on short-term purchases could exacerbate existing problems on the utilities' systems.

28. Too much reliance on short-term purchases could increase costs and ultimately obstruct many of our resource planning goals.

29. A "portfolio" strategy involves looking to diverse sources rather than a single source in developing long-term electric resource plans.

30. Having our utilities look to independent sources and to other utilities for supply- and demand-side resources has many benefits, such as competitive pricing, technical innovation, and diversity of size, location, and technology.

31. An important reason why we have frequent Updates (every two years) is that our forecasts of future conditions are constantly changing. Resource plans must be revised frequently, and utilities must always have the ability to make resource commitments between Updates.

32. A drastic makeover of any utility system in any one Update is not reasonable.

33. The IDRs designated for PG&E constitute a tiny portion of its system capacity; they also do not significantly increase the number of QFs on PG&E's system even if they are fully subscribed.

34. Edison's IDRs, compared to PG&E's, constitute a somewhat higher but still quite small portion of the Edison system.

35. SDG&E has significant reliability-based need over the next eight years, and under all of its scenarios would be increasing its system capacity by one-third or more. The limits we place on SDG&E's solicitation keep the QF contribution to its total capacity in line with the other utilities. They also ensure that

SDG&E will fill its large resource needs from a variety of sources, not just QFs and not just this solicitation.

36. SDG&E has supported a "go short" strategy which always reserves, for provision through short-term purchases, 50% of its perceived long-term need.

37. The base case scenario for each utility in the Update derives, with very limited exceptions, from the CEC's supply and demand forecasts in its latest Electricity Report. The utilities also have broad latitude to explore the effects of uncertainty, which they generally do through alternative scenarios. The goal is resource plans that work well even if the future differs from the forecasts, as it always does in greater or lesser degree.

38. The base case scenario indicates "ideal" timing, i.e., how soon the utility would add a particular resource were it not constrained by the permitting and construction process.

39. The proposed "existing plant" exception (viz., that costs of residual emissions would be ignored in analyzing any purchase of power from an existing plant) would signal that California is committing to generation with high emissions both for the short- and long-term. The proposed exception should be rejected.

40. Every resource that goes into a long-term plan necessarily backs down some other resource.

41. We designate two IDRs for PG&E: (1) the repower of Hunters Point Units 2 and 3, for a total of 221 MW net capacity, and (2) a variable speed wind IDR of 22.5 MW effective capacity (150 MW gross capacity).

42. Although PG&E's filing indicates that the Hunters Point repower is a cost-effective resource addition in 1992, PG&E's system does not have reliability-based need. We therefore set an on-line date of 1997 for this repower in order to maximize competition among QF bidders.

43. We designate the variable speed wind IDR as a set-aside in compliance with PU Code Section 701.3. Since PG&E originally

found the variable speed wind IDR to be cost-effective in 1998, we adopt 1998 as the on-line date for this IDR. Concerning the capacity factor to be assumed for the IDR, PG&E should use 27% or a lower capacity factor, calculated as suggested by U.S. Windpower in its reply comments on the Proposed Decision.

44. Although only a limited number of variables need be tested in order to reasonably investigate uncertainty, both the high and low ranges should be tested and both the variables and the ranges must be chosen with care.

45. A "turnkey" quote is a method of construction whereby the contractor assumes total responsibility from design through completion of the project.

46. Generation resource options should meet a minimum size criterion to justify the expense of holding an auction. The telemetering requirement for QFs (10 MW and above) on the PG&E and Edison systems is a logical threshold for IDRs on those systems.

47. The geographical restriction placed on bidders against PG&E's Hunters Point IDR make it unsuitable for set-aside purposes. Renewable IDRs also provide a more appropriate bidding benchmark for renewable QFs.

48. Turnkey projects may provide a way to lower the cost of renewable technologies and increase utility participation, both of which seem desirable. Moreover, the contractor in a turnkey project bears the risk of developing the project at the contract price; this factor largely negates our reasoning in deciding not to hold the utility to the benchmark price if it builds the IDR.

49. PG&E modeled the stream of capital costs associated with its wind IDRs so that a "balloon" occurs at the end of the variable speed machine's 20-year useful life. For later Updates, this method for treating capital costs does not appear appropriate either for cost-effectiveness analysis or for payments under final Standard Offer 4.

50. But for the constraints of the San Francisco Operating Criterion, we would have made the Hunters Point repower deferrable by QFs regardless of their location.

51. We designate the Encina 1 repower (273 MW net) and 200 MW of geothermal, for a total of 473 MW, as SDG&E's IDRs. We set aside half of the geothermal capacity for renewable bidders, pursuant to PU Code Section 701.3.

52. SDG&E needs resource additions now.

53. Although repowers were found cost-effective for SDG&E as early as 1992, we choose later on-line dates in order to reduce lumpiness and maximize competition among QFs while obtaining generation for SDG&E's system soon. We therefore establish the following on-line dates for the Encina repower IDR: 1995 will be the on-line date for 135 MW and 1996 will be the on-line date for 138 MW. The benchmark price for both years will be based on the Encina 1 repower's costs and emissions characteristics, with appropriate escalation for the later on-line date.

54. Although some SDG&E scenarios show geothermal additions to be cost-effective as early as 1992, we designate 1997 as the on-line date for 100 MW of geothermal and 1998 as the on-line date for the other 100 MW of geothermal. Staggering the IDR on-line dates from 1995 through 1998 will provide SDG&E with planning flexibility and avoid lumpiness problems.

55. SDG&E's transmission situation inclines us to limit the solicitation for this Update.

56. SDG&E has failed to show that the repower of South Bay 3 provides unique and nonduplicable benefits, through either an associated desalination facility or alleged voltage support and land use benefits, such that a deferral of the repower would be wasteful.

57. ERCE argues that SDG&E has manipulated the screening process to favor SDG&E's internal projects over those of outside suppliers. ERCE believes that if its proposal is not selected as

an IDR, it has no means, as an IPP, to compete to fill part of SDG&E's resource need. ERCE has not presented persuasive evidence to show that SDG&E should have ranked its proposal higher.

58. Non-QFs, including IPPs, have other ways to deal with SDG&E than by offering up IDRs for QFs to bid against.

59. The capital and running costs used in cost-effectiveness calculations for candidate IDRs are issues appropriate for litigation in the Update. Questions on utility management decisions, like SDG&E's handling of Heber and of the requests for proposals, are properly the subject of traditional reasonableness review, and are not appropriate issues to consider in the Update.

60. Even in retiring the Heber plant, SDG&E has an obligation to its ratepayers to obtain maximum value.

61. In the next Update, the utilities shall use the emissions limits of the local air district that are in effect or likely to be in effect during the bulk of the period modeled for cost-effectiveness analysis. If the local air district is contemplating a new limit, the affected utility shall examine if and how that new rate would alter its planning results.

62. The parties disagree with SDG&E's geothermal cost data used for its geothermal IDRs. Edison's method of determining geothermal costs, based on ER-90 data, is better documented on the record than SDG&E's. However, even Edison's costs do not fully comport with ER-90.

63. SDG&E has demonstrated its strategic reasons to prefer the Encina 1 repower. Making the South Bay 3 repower an IDR would result in a larger total solicitation than we deem appropriate for SDG&E at this time.

64. For Edison, we designate as IDRs the Huntington Beach 3 repower (385 MW net), 300 MW of geothermal, and 50 MW (effective capacity) of wind. Half of the geothermal and wind capacity is set aside for renewable bidders, pursuant to PU Code Section 701.3.

65. Since Edison's system does not have reliability-based need, we choose the on-line dates of its suggested alternative plan, namely 1997 for the wind IDR and 1998 for the Huntington Beach repower, in order to promote as much competition among QFs as possible.

66. Since Edison's system does not have reliability-based need, and in order to avoid lumpiness problems, 1997 will be the on-line date for 100 MW of the geothermal and 1999 will be the on-line date for 200 MW.

67. Edison's base case resource plan relies heavily on uncommitted DSM, which meets about 65% of Edison's need during the deferral window.

68. When Edison's All-DSM Plan is rejected and Edison's suggested alternative plan is understood, Edison's overall perception of need is quite similar to the Commission's.

69. Since Edison's system is overwhelmingly fossil-fueled, we choose renewable IDRs for almost half of the solicited capacity.

70. Edison's "CPUC Base Case," which results in a far greater assessment of need for Edison than ER-90 indicates, is neither required nor approved by our resource procurement decisions. Edison chose not to support its All-DSM strategy despite this Commission's repeated invitation to Edison and the other respondents to include in their resource plan showings a description and justification of their strategic preferences.

71. This Commission vigorously supports DSM programs.

72. The major concerns about Edison's All-DSM Plan include the following: (1) the plan is not least-cost; (2) the plan is prematurely made, before Edison has completed its integrated planning DSM pilot project; (3) the plan is unprecedented and implausible, in that it assumes almost twice as much DSM as ER-90, which already relies on uncommitted DSM to meet about 2/3 of Edison's resource need through 1999; (4) the plan is inconsistent with ER-90; (5) the plan is high risk; (6) the plan is a bad

investment strategy; (7) the plan is inconsistent with Edison's announced planning objectives; (8) the plan elevates one worthwhile planning goal to absolute supremacy while neglecting all others; (9) the plan inappropriately allocates risk between shareholder and ratepayers; and (10) the plan contains unaccounted for costs.

73. The aspects of the repower of San Bernardino Units 1 and 2 that Edison claims justify nondeferrability are not shown to be unique or impossible for QFs to provide.

74. The final Standard Offer 4 procedure captures the economic benefits of using existing equipment and transmission lines at an already developed site. The low cost of the repowering at an existing site is reflected in the IDR's lower costs compared to other resource options, and it is these lower costs that become the benchmark against which a QF bids.

75. Using the Nevada residual emissions values for plants in attainment areas, 1100 MW of geothermal are cost-effective for Edison over the next eight years.

76. Our review of ER-90 and its supporting documentation indicates the CEC developed both fixed and variable geothermal O&M costs.

77. Edison's capital and O&M costs for San Gorgonio and Tehachapi wind generation are the same, but the transmission line and substation upgrade costs at San Gorgonio are lower.

78. ER-90 remains in place until ER-92 supersedes it.

79. Since this is the first time that the utilities will issue solicitation packages for final Standard Offer 4, it is prudent to develop a procedure by which the parties can preliminarily review the solicitation packages in order to prevent delay or confusion that could result from typographical errors, omissions, or other problems with the packages turning up after the utilities have published them.

80. Transphase's petition to intervene is not reasonably pertinent to the issues already presented in the Update and would unduly broaden those issues.

81. An integrated bidding pilot (or pilots) could easily be subsumed within the overall level of resource additions adopted in today's order without "counting against" QF-deferrable generation.

82. One of the fundamental goals of coordination between the CEC and the CPUC in the ER/Update process would be frustrated if winners from a solicitation based on one ER were to have an "economic need" test applied at the CEC based on a later ER.

83. Under our "alternative" planning scenario in this phase of the Update, the values assigned to residual emissions vary, depending upon where those emissions are generated. Emissions occurring in nonattainment areas are valued using the purchasing utility's marginal cost of control, but emissions occurring in attainment areas are assigned values adopted by the Nevada Public Service Commission. We call this method nonuniform valuation.

84. Based on the record in this case, nonuniform valuation is more appropriate for California than is uniform valuation.

Conclusions of Law

1. PG&E, SDG&E and Edison all have need of new or additional electric generation that should be filled at this time.

2. Meeting the state's objective of minimizing the environmental costs of providing electric service is one of several important objectives the Commission must balance. Equally important are the traditional objectives of reasonably priced, reliable service for all ratepayers.

3. PU Code Sections 701.3 and 701.4, enacted on January 1, 1992, govern resource procurement in this Update. Since our methodology does not yet quantify the value of fuel diversity, the provisions of Section 701.3 require us to "set aside" a portion of generating capacity for renewable resources in the coming bid solicitation.

4. For purposes of the renewables set-aside, we adopt the definition of non-fossil resources that we used in D.91-06-022, i.e., generation resources that do not use oil, coal, or natural gas as their primary fuel source. Qualifying projects would include wind, hydro, geothermal, solid waste, biomass, and solar projects. Such a project must not use any amount of oil or coal, but may use natural gas for no more 25% of its total energy input during a calendar year. A project acquired through the set-aside must certify compliance with these fuel use restrictions as part of its commitments under its final Standard Offer 4 contract.

5. The addition of residual emissions valuation to ICEM precludes reliance on a single ICEM scenario for resource planning purposes at this time.

6. The following rules are adopted now for administering the set-aside capacity solicitation in this Update. First, each set-aside will have benchmark prices set by a renewable IDR. Second, except for PG&E, all technologies will be allowed to bid against renewable IDRs, but at least half the capacity of each renewable IDR will be awarded to renewable bidders (assuming there are sufficient renewable QF bidders to fully subscribe the set-aside). Third, second-price auction rules apply to the price awarded the winning bidders.

7. Since PG&E's wind IDR is a small IDR in absolute terms and also in comparison to PG&E's repower IDR, bidding on this wind IDR should be limited to renewable QFs.

8. Our policy of recognizing the environmental costs of residual emissions of different generation resource options should apply to all resource types and all fuel sources.

9. Failing to include environmental objectives in our choices for the long term would prevent us from achieving our goal of environmentally sensitive, least-cost electricity service.

10. The Update long-term procurement process should not contain special exclusions for particular generation technologies,

generation sites, or pollutants. The same procedures, including valuation of emissions, ought to apply to all technologies and to all plants, whether existing at the time of the Update or to be constructed. This conclusion follows directly from our commitment to a "level playing field" for competing sources of supply.

11. Utilities are authorized to make resource acquisitions outside the Update process using their best judgment and subject to reasonableness review.

12. Given the uncertainty over policy addressing climate change, PG&E, SDG&E, or Edison should undertake a long-term purchase only if the supplier provides assurance that it alone will bear the cost of meeting any future costs resulting from a carbon tax, acquisition of tradeable emission permits, retrofits, or any other carbon emission control strategy or regulation applicable to the supplier's plant(s).

13. In future Updates utilities should present (1) a private cost scenario (with emissions valued at zero) and (2) a scenario valuing residual emissions based on the purchasing utility's marginal cost of emission control, as discussed in this decision.

14. The costs of offsets already owned and exemptions from offset requirements should be included in determining the costs of the repower project. Where we designate repowers as IDRs, the utility should correct the IDR's capital costs to include the full cost of offsets.

15. The utilities should correct their published bid solicitations for this Update based on repower IDRs so that only the emission offsets and offset ratios associated with the incremental capacity of the repower would be netted against the total repower emissions. The utilities should also correct their published bid solicitation for this Update so that the IDR's capital costs are based upon DRA's method for calculating offset costs.

16. For this Update and until further order, utilities should evaluate short-term purchase options (those of five years duration or less) on a traditional least-cost basis, i.e., without factoring in residual emissions costs. Not applying a residual emissions analysis to short-term purchases will ease the transition phase, and will help cushion any potential rate impact which may result from incorporating externalities in evaluating long-term purchases. This bifurcated approach in valuing short-term purchases is an interim policy.

17. In future Updates, the utilities shall continue to perform their long-term resource plan cost-effectiveness analysis by counting air emission costs for all resources once they are added to the utility system, even if the added resource is short-term.

18. Ignoring residual emissions in a cost-effectiveness analysis for both short- and long-term purchases from existing plants (the "existing plant" exception) would subvert the policies of PU Code Section 701.3.

19. PG&E, subject to two alternative conditions, should pursue the variable speed wind IDR or another renewable project if the IDR is not substantially fully subscribed. First, PG&E may itself develop the renewable capacity if it is willing to accept the benchmark price as a cost cap. Second, if PG&E chooses not to develop the renewable capacity itself, it must pursue the IDR if U.S. Windpower is still willing to proceed under the terms and conditions of its turnkey quote.

20. Only QFs in San Francisco and Northern San Mateo County should be eligible to defer the repower of Hunters Point Units 2 and 3.

21. SDG&E will be able to fill its remaining need, and respond to the CEC's recommendation of renewable capacity beyond that amount set aside in today's decision, from its other resource options.

22. A.91-08-028, in which SDG&E requested we find nondeferrable its proposed South Bay repower, is denied because SDG&E has failed to adequately justify that finding. Our rejection of SDG&E's request does not preclude SDG&E from pursuing the South Bay repower, either linked with the desalination facility or as a stand-alone project.

23. ERCE's request that we reject SDG&E's resource plan, or require SDG&E to revise its evaluation process by using an independent party to evaluate potential IDRs, should be denied.

24. Edison's request that the repower of San Bernardino Units 1 and 2 be deemed nondeferrable should be denied.

25. For purposes of preparing a bid solicitation package, we direct both SDG&E and Edison to use the complete set of fixed and variable costs developed by the CEC staff in ER-92 for liquid-dominated flash geothermal technologies. (See Technology Characterization Report, October 11, 1991.)

26. In their bid solicitation packages, SDG&E and Edison should specify the KGRA in which their respective geothermal IDRs would be located. For SDG&E, the KGRA should have sufficient resource potential to accommodate SDG&E's IDRs and, in relation to SDG&E's system, should have lower transmission upgrade costs than other KGRAs. Edison's designation of KGRA should follow the same criteria, as applied to Edison's geothermal IDRs and transmission upgrade costs.

27. If a decision in our transmission access investigation (I.90-09-050) entails changes to the final Standard Offer 4 contract, the assigned ALJs should ensure that these are incorporated in the contract as expeditiously as possible.

28. The assigned ALJs should promptly schedule a workshop or prehearing conference to consider the appropriate method, scope, and timing of a pre-publication review of the utilities' solicitation packages.

29. The assigned ALJs should request the parties' views on whether the bidding and scoring approach set forth in Attachment 6, or some other suggestion, is a desirable or feasible alternative in this Update cycle to a simple one bid per QF per IDR approach. If not, then the solicitation should proceed under the latter approach.

30. Consideration of unresolved issues regarding sales by QFs to multiple entities, terms for as-available sales in excess of firm commitment, and aggregation of IDRs for bidding purposes is timely.

31. The review of methodological issues in Phase 3 will be limited. In particular, no matter resolved in D.91-06-022 or in today's decision (except where noted) is subject to reconsideration in Phase 3.

32. The assigned ALJs should schedule a prehearing conference to schedule and coordinate activity in Phase 3. Any party proposing an issue for Phase 3 must justify inclusion of that issue and state specific reasons for its timeliness and relative importance.

33. Before the next Update cycle starts, CACD should develop a common format for use in ratepayer impact exhibits in the Update. CACD should consult with the utility respondents and other parties, and may hold one or more workshops for this purpose.

34. Since a bid solicitation should be held as soon as possible in 1992, this order should be effective immediately.

35. Transphase's petition to intervene does not comply with Rule 54 of the Commission's Rules of Practice and Procedure. The petition should be denied without prejudice.

36. PU Code § 747 requires that we assess the feasibility and implications of implementing the tested bidding systems before making recommendations on whether DSM bidding systems should be used to fulfill future electric utility resource needs.

37. Even if Transphase were permitted to intervene in the Update, its motion for consolidation of integrated bidding into the Update is unreasonable and would be denied.

38. The CEC's latest gas price forecast, adopted November 6, 1991, for use in ER-92, should be used in evaluating bids in the auction conducted pursuant to today's decision.

39. Nonuniform valuation should be used for the base case analysis in our proceedings for electric resource planning and acquisition.

40. Any adder (or subtractor) for a winning QF should be computed using the emission values for the QF's generation site.

41. The issue of whether a QF's residual emissions should be calculated net of required offsets should be reconsidered.

42. For the purposes of consistency, we should also assess the cost-effectiveness of DSM programs utilizing the ER-92 gas price forecast.

## INTERIM ORDER

IT IS ORDERED that:

1. Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company shall each prepare a bid solicitation package in conformance with the discussion, findings, and conclusions set forth in this decision. The assigned Administrative Law Judges shall schedule the preparation, review, and publication of the bid solicitation packages. The schedule shall allow effective coordination of these activities with Investigation 90-09-050 and with modifications to the final Standard Offer 4 contract and bidding protocol pursuant to Decision 91-06-022 and this decision.

2. Application 91-08-028 is denied and that proceeding is closed.

3. The assigned Administrative Law Judges shall convene prehearing conferences or workshops in conformance with the discussion, findings, and conclusions in this decision.

4. Before the next Biennial Resource Plan Update (Update) cycle commences, the Commission Advisory and Compliance Division (CACD) shall develop a common format for use in ratepayer impact exhibits in the Update. CACD shall consult with the utility respondents and other parties, and may hold one or more workshops for this purpose.

5. The Petition of Transphase Systems, Inc. to Intervene in the Biennial Resource Plan Update and Related Applications is denied without prejudice.

6. The petitions to intervene of BHP Minerals International Inc. and Peabody Coal Company are granted. All other motions and requests still outstanding in this phase of the Update are denied.

This order is effective today.

Dated April 22, 1992, at San Francisco, California.

DANIEL Wm. FESSLER
President
JOHN B. OHANIAN
PATRICIA M. ECKERT
NORMAN D. SHUMWAY
Commissioners

We will file a written concurring opinion.

/s/ JOHN B. OHANIAN
Commissioner

/s/ PATRICIA M. ECKERT
Commissioner

I CERTIFY THAT THIS DECISION WAS APPROVED BY THE ABOVE COMMISSIONERS TODAY.

Neal J. Shulman

NEAL J. SHULMAN, Executive Director

pb

## Table of Acronyms and Abbreviations

| | |
|---|---|
| A. | Application |
| AB | Assembly Bill |
| ALJ | Administrative Law Judge |
| CACD | Commission Advisory and Compliance Division |
| CEC | California Energy Commission |
| CEERT | Coalition for Energy Efficiency and Renewable Technologies |
| CPUC | California Public Utilities Commission |
| D. | Decision |
| DRA | Division of Ratepayer Advocates (Part of CPUC staff) |
| DSM | Demand-side Management |
| Edison | Southern California Edison Company |
| ER-90 | 1990 Electricity Report of the CEC |
| ER-92 | 1992 Electricity Report of the CEC |
| ERCE | ERC Environmental and Energy Services Company, Inc. |
| GRA/IEP | Geothermal Resources Association and Independent Energy Producers Association |
| I. | Investigation |
| ICEM | Iterative Cost-effectiveness Methodology |
| IDR | Identified Deferrable Resource |
| IPP | Independent Power Producer (any nonutility generator of electricity other than a QF) |
| KGRA | known geothermal resource area |
| MW | Megawatt (one million watts) |
| NOx | Nitrogen/Oxygen Compounds |
| O&M | Operating and Maintenance Costs |
| PG&E | Pacific Gas and Electric Company |
| PR Code | California Public Resources Code |
| PU Code | California Public Utilities Code |
| PURPA | Public Utility Regulatory Policies Act |

| | |
|---|---|
| QF | Qualifying Facility |
| R. | Rulemaking |
| RT | Reporter's Transcript |
| San Diego APCD | San Diego Air Pollution Control District |
| SoCalGas | Southern California Gas Company |
| South Coast AQMD | South Coast Air Quality Management District |
| SDG&E | San Diego Gas & Electric Company |
| SONGS 1 | San Onofre Nuclear Generating Station, Unit 1 |
| SO2 | Sulfur Dioxide |
| SOX | Sulfur/Oxygen Compounds |
| Transphase | Transphase Systems, Inc. |
| Update | Biennial Resource Plan Update |

(END OF ATTACHMENT 1)

## Landmark CPUC Decisions on Avoided Cost, Standard Offers

The following list, although not exhaustive, shows where to find answers to the key questions that the Commission has addressed regarding QFs. The summaries are necessarily terse and are not intended either to indicate each issue in any given decision or to substitute for review of the actual text of the opinion and order. In addition to these decisions, our general rate case decisions have been used in the past to update certain standard offer terms. Finally, decisions in general rate case and fuel offset proceedings often contain analysis of marginal cost that is broadly relevant to QF policy.

I. Foundational Decisions

D.91109 - adopted "avoided cost" pricing for utility purchases from "private energy producers"

D.82-01-103 - guidelines for standard offers

D.82-04-071 - authorized "hydro savings prices" during spill conditions

D.85-07-022 - long-run avoided cost methodology

II. Decisions Implementing Variable Energy Payments and Standard Offers 1 2, and 3 (the Short-run Offers)

| | | |
|---|---|---|
| D.82-12-120 | D.84-03-092 | D.88-07-024 |
| D.83-10-093 | D.84-04-012 | D.89-02-065 |

III. Decisions on Interim Standard Offer 4 (the Interim Long-run Offer): See Attachment 2 of D.91-06-022

IV. Show Cause Proceeding (PG&E)

D.84-03-093
D.84-08-031 - "good faith" guidelines for utilities in negotiating with QFs

V. Investigation of Transmission Constraints, Development of QF Milestone Procedure, and Administration of Transmission Priority

| | | |
|---|---|---|
| D.84-08-037 | D.85-12-075 | D.87-08-028 |
| D.85-01-038 | D.86-02-033 | D.87-09-030 |
| D.85-01-039 | D.86-04-053 | D.88-04-067 |
| D.85-08-045 | D.86-11-005 | D.89-01-044 |
| D.85-09-058 | D.86-12-017 | D.89-07-058 |
| D.85-11-017 | D.87-04-039 | D.91-04-040 |
| | | D.91-11-053 |

VI. Standard Offer 2: Suspension and Reinstatement: See Attachment 2 of D.91-06-022

VII. Development of the Resource Plan-based Offer (Final Standard Offer 4)

| | | |
|---|---|---|
| D.85-07-022 | D.87-11-024 | D.89-04-047 |
| D.86-07-004 | D.88-03-026 | D.89-07-045 |
| D.86-10-030 | D.88-03-079 | D.90-03-060 |
| D.87-05-060 | D.88-09-026 | D.90-06-027 |
| | | D.91-06-022 |

VIII. "Orphans," "Pioneers," and Nonstandard Contracts: See Attachment 2 of D.91-06-022

IX. Energy Reliability Index (ERI): Capacity Valuation Methods

| | | |
|---|---|---|
| D.86-11-071 | D.88-03-079 | D.89-06-048 |
| D.91-11-057 | | |

X. Out-of-Service Area QFs

D.88-04-070 D.88-09-067

XI. Avoidable Gas Costs

D.88-07-024 D.89-09-099 D.90-12-028

XII. Contract Administration

D.88-10-032 in R.88-06-007 (Guidelines)

(END OF ATTACHMENT 2)

## Summary of Standard Offers[1/]

**STANDARD OFFER 1:** Variable Capacity and Energy

The QF's energy and capacity are sold on an as-available basis, meaning that the amount and time of delivery of the energy is not guaranteed. The QF is paid full short-run avoided energy cost, plus current shortage cost, on a per kilowatt-hour basis, for all energy delivered to the utility. Energy and shortage costs are updated quarterly and annually (respectively), with the energy cost based on the incremental energy rates established in the utility's last fuel offset proceeding and the expected fuel costs for that quarter. Shortage costs are based on the utility's cost of a combustion turbine. This contract is used by all technologies, but particularly wind, due to the uncertain nature of that resource.

**STANDARD OFFER 2:** Firm Capacity and Variable Energy

The QF's capacity is sold on a firm basis, meaning that an amount of capacity is guaranteed to be available to the utility during its peak load period. The capacity payments are based on levelized, forecasted shortage costs, which are stated in the contract and are fixed for the life of the contract. Energy prices are the same as in Standard Offer 1. Many cogenerators and biomass QFs hold Standard Offer 2 contracts.

**STANDARD OFFER 3:** Variable Capacity and Energy From QFs Not More Than 100 Kilowatts

This offer is the same as Standard Offer 1 in practice, but the contract terms and QF responsibilities are less involved, due to the small size of the facilities.

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1/ Source: D.88-09-026 (in A.82-04-44 et al.), Appendix D.

ATTACHMENT 4
Page 1

## How Final Standard Offer 4 Works[1/]

Unlike the short-run standard offers and the interim long-run standard offer, final Standard Offer 4 derives from the respective utility's resource plan (including potential new plant construction, refurbishments, power purchases, etc.), as reviewed by the Commission in a biennial update proceeding. Pricing under final Standard Offer 4 varies according to when the QF comes on-line. During Period 2, the QF avoids a specific utility generation resource, and the QF receives payments based on the fixed and variable costs of the avoided resource. If the QF comes on-line in Period 1, i.e., before the date when the avoided resource would have begun delivery of electricity, the QF meets near-term demand growth, and therefore the QF receives short-run marginal cost-based payments until the start of Period 2. The Commission considers uncertainties and procurement strategies for each utility in determining a megawatt (MW) limit at each update proceeding. Whenever the capacity of QFs seeking final Standard Offer 4 contracts from a given utility exceeds that utility's MW limit, the available contracts are allocated through bidding. The utilities are also authorized to pay QFs additional sums for providing performance features (e.g., downward dispatchability at the utility's direction) not otherwise required under the standard offers.

We have adapted the following chronological overview from prior orders. We think the details of the final Standard Offer 4 resource planning process are more easily grasped with the total design in mind.

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1/ Source: D.88-09-026 (in A.82-04-44 et al.), Appendix A.

Step 1: The utility application. Following the latest Electricity Report of the California Energy Commission (CEC), the Pacific Gas and Electric Company, the San Diego Gas & Electric Company, and the Southern California Edison Company each file a resource plan with a 12-year planning horizon. The plan identifies within the horizon those potential resource additions that the applicant believes are cost-effective for its system. The plan states the costs associated with each such resource and the point in the planning horizon when that resource becomes cost-effective. The plan also states all relevant assumptions. The applicant presents its assumptions in internally consistent "scenarios." The latest CEC Electricity Report forecasts give the supply and demand assumptions for the base case scenario. The applicant may also file additional scenarios, or otherwise deal with the range of uncertainties underlying the forecasts, in order to explain the applicant's preferred procurement strategy.

Step 2: Hearings on the utility applications. The Commission's staff and other participants critique each resource plan. They may note internal inconsistencies in any of the applicants' scenarios, present alternative scenarios of their own, criticize the applicant's assessment of uncertainty, and challenge the reasonableness of an applicant's assumptions. They also check that the applicants have correctly implemented the Commission's cost-effectiveness methodology. Finally, these participants may explain their choice of the scenario best suited to the determination of avoidable plants.

Step 3: Commission determination of avoidable plants for the respective utilities. Avoidable plants are essentially the cost-effective baseload or intermediate resource additions appearing in the first eight years of the resource plan that is preferred by the Commission. This choice is the key Commission act

in the long-run standard offer process. The Commission makes this choice according to the following criteria, among others: Are the plan and underlying assumptions plausible (i.e., internally consistent and reasonable, given known forecast uncertainties)? Does the plan expose ratepayers to unnecessary risks, either of premature commitments or of shortages? Is the plan consistent with energy regulatory goals and policies? The Commission decision comes about five months after filing of the applications.

Step 4: <u>The utilities' solicitation process and QF auction</u>. After making any modifications ordered by the Commission, the utilities announce the availability of long-run standard offer contracts based on the capacity and the fixed and variable costs of the avoidable resource(s). QFs have a three-month solicitation period to respond. Each interested QF indicates (1) the resource that the QF seeks to avoid, (2) the QF's own technology and capacity, and (3) the QF's bid, which is the lowest percentage of the resource's fixed costs that the QF would be willing to accept. The bid cannot exceed the resource's fixed costs. The utility opens the responses at the end of the solicitation period. If QFs seeking to avoid a resource do not cumulatively exceed the resource's capacity, all these QFs are offered contracts at the full fixed costs of the resource. If such QFs do exceed the resource's capacity, contracts up to that MW limit are offered to the low-bidding QFs, and they receive that percentage of the resource's fixed costs bid by the lowest <u>losing</u> bidder. (This is known as a "second price" auction.) Contract signing occurs after the winning bidder complies with the prerequisites of the QF Milestone Procedure, roughly one year after the utility applications.

Step 5: Update to the long-run standard offer. The update is scheduled every two years and follows each CEC Electricity Report. The utilities file new resource plans, and Steps 1 through 4 are repeated, with such modifications to the process as the parties may suggest and the Commission approves.

(END OF ATTACHMENT 4)

ATTACHMENT 5
Page 1

Background Information on
Air Quality and Fuel Diversity

This attachment reproduces Sections IV.B and IV.C (with the original footnote numbering) from D.91-06-022, which is the decision where the Commission adopted its method for factoring air quality and fuel diversity considerations into least-cost electric resource planning. These sections summarize background information that is well-known to most of the parties to the Update but that the general reader may find useful. Please note that the offset ratios cited near the end of the attachment were current as of the adoption of D.91-06-022 (June 1991). Higher offset ratio requirements are either adopted or under consideration for San Diego and the San Francisco Bay Area.

B. Background

ER-90 made major advances over prior California resource planning efforts in its approach to environmental quality and fuel diversity. All parties agree that these factors should affect an electric utility's choices in meeting future demand on its system, but there is little agreement on how the utility should take them into account.

Part of the difficulty is that these factors' impacts on utility costs and society are not easy to calculate. The value of fuel diversity depends on assessing the financial risks of relying too much on a given fuel, and on calculating how best to insure against those risks. As for environmental quality, the producers (including utilities) that create pollution have generally not had to bear all the costs of pollution but have instead "externalized"

a substantial part of those costs to society as a whole. The utilities logically should bear their fair share of such costs, although the size of that share is debatable.

For purposes of this discussion, acquiring "fuel diversity" for California utilities means increasing the proportion in their resource mix of electricity generated by plants that do not rely on oil, coal, or natural gas as their primary fuel source. Some technologies burn small amounts of natural gas, e.g., gas-assisted solar. A power plant using such a technology would still be considered non-fossil if it uses natural gas for no more than 25% of its total energy input during a calendar year.[9]

"Environmental quality" includes air, water, and land use considerations. Most parties would limit evaluation efforts during this ER/BRPU cycle to air quality impacts.[10] The reason for the limitation is that the analysis of air quality impacts has been spurred by recent state and federal clean air legislation and actions by local air management districts. California utilities, along with other major sources of air pollutants, are facing major clean-up costs now or in the near future. Air basins in California must now achieve annual reductions in total emissions of specified air pollutants, and this will inevitably affect how each electric utility plans and operates its system.

The imminence of these air quality problems convinces us that the priority given to evaluation of air quality impacts is appropriate. However, all Californians know that the state has a

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9 The record does not clearly define fuel diversity; however, our concept (adapted from testimony by PG&E witness Ross in Exhibit 207, page 6) does not appear controversial.

10 The exceptions are Edison, which has a proposal regarding land use, and SDG&E, which could include water and land use in the post-bidding phase of the resource acquisition process that it proposes. For further discussion of parties' positions, see Section IV.D below.

water crisis. Environmental review during the permit process for new power plants should ensure that the plants have acceptable environmental impacts, but only if water is included along with other environmental considerations in procuring new generation will a power plant project that preserves our water resources be able to use that fact to competitive advantage. We urge that power plant impact on water resources be further examined in the next ER/BRPU cycle.

C. Air Quality Overview

The following discussion serves chiefly to introduce some terms and concepts that are inevitable when relating air quality to electric generation.

Ambient air quality standards (AAQS) apply to a rogue's gallery of hazardous substances. These "criteria pollutants" include certain sulfur/oxygen compounds (SOx), carbon monoxide, lead, particulate matter in suspension (PM), a group collectively referred to as reactive organic gases (ROG), and ozone, which is a principle component of smog. Nitrogen/oxygen compounds (NOx) are "precursors" (through chemical reactions in the atmosphere) to criteria pollutants, and also contribute to acid deposition, a non-criteria pollutant.[11] Carbon dioxide is also considered a pollutant because it is a "greenhouse" gas and so contributes to possible global warming.

Concentrations of criteria pollutants in excess of AAQS are unhealthy. When the concentration of a given criteria pollutant in an air basin regularly violates AAQS, the air basin is designated a non-attainment area. PG&E, SDG&E, and Edison all serve major metropolitan areas that are also non-attainment areas.

California is moving aggressively to address its air quality problems. "Beginning in 1988, the California Clean Air Act

11 We will follow ER-90 usage in referring to NOx as a criteria pollutant.

requires that local districts reduce emissions of non-attainment pollutants or their precursors by 5% per year (by air basin). Local districts are required to develop new air quality attainment plans to meet [AAQS] by December 1991. These plans include more restrictive emissions limitations for existing sources and new procedures for permitting new sources." ER-90, page 5-4 (footnote omitted). These requirements also apply to districts that are themselves in attainment but that contribute to attainment problems downwind.

Air management districts have the ability to require retrofits of power plants as part of these plans. Also, air management districts may require new sources to apply the best available control technology (BACT). SCAQMD has taken both of these actions to deal with NOx emissions. Proposed Rule 69 of the San Diego County Air Pollution Control District would apply a more stringent NOx emission standard than SCAQMD's and would cover virtually all utility electrical turbines and boilers in the district. ER-90 assumes that NOx retrofit requirements will be adopted in both San Diego and Ventura Counties.

New sources may also have to acquire "offsets" of any residual emissions after application of BACT by arranging to reduce emissions from an existing source. Specifically, regulations of the federal Environmental Protection Agency require that all increases in emissions resulting from a major new source must be mitigated by the <u>permanent</u> reduction of emissions from existing sources. "Offset requirements are administered by local air districts and are set on a site-specific basis." (ER-90 at page 5-7.) Air management districts in non-attainment areas may require such offsets in a ratio greater than one-to-one. This is the case with the San Francisco Bay Area (1.1:1), Los Angeles (1.2:1), and San Diego (1.2:1) air basins.

Many of the pollutants mentioned above are produced when fossil fuels are burned. In particular, burning oil and gas will produce NOx. The CEC notes that in its ICEM analysis, NOx was the only pollutant whose value actually affected the timing of new resources, and NOx accounted for almost half the total value attributed to residual emissions.[12]

(END OF ATTACHMENT 5)

12 ER-90, page 6-12. The CEC says the predominance of NOx is due to the small amounts of SOx, PM, and ROG put out by power plants relative to their NOx emissions. Also, according to the CEC, NOx emitted from all sources is subject to stringent controls, which leads to a higher social value per ton. A third of the total residual emissions value in ER-90 came from carbon. Id.

## Considerations for Bidding With Multiple IDRs and Set-asides

This proposal is set forth in order to stimulate further discussion of various bidding and scoring issues raised by the decision at Section 8.1. Although this proposal does not specifically state how different transmission costs and on-line dates factor into the bidding and scoring methods discussed here, the workshops and discussions should also address whether this proposal, or minor modifications to it, is sufficient to address these specific considerations.

### 1. Desired Auction Outcome

This proposal assumes that the desired auction outcome is the most efficient selection of least-cost resources, taking into consideration multiple IDRs with differing emissions profiles, compliance with legislated set-aside requirements, and price(s) set by the lowest losing bidder(s).

### 2. Bidding and Scoring Issues

#### 2.1 Multiple IDRs

If only one IDR exists, every bidder competes against every other bidder and no strategic bidding due to IDR choice occurs. However, in the case of multiple IDRs, assuming there is no aggregation of IDRs and bidders can choose what IDR to bid against, bidders are likely to select the IDR that combines the best chance of winning with the highest level of rents. A poor auction outcome could result if QFs game the auction in this way while lower-priced IDRs that these QFs might still be able to beat go under-subscribed.

This proposal recommends adoption of rules to avoid strategic bidding and achieve the optimal group of winners for all of the IDRs offered by a given utility. There are different options to consider, including: (1) require the QF to submit one bid applicable to all IDRs; (2) allow the QF to submit multiple bids and allow the utility to select the IDR for which the QF receives a contract; or (3) require the QF to submit a bid (but not necessarily the same bid) for every IDR and fill the IDR capacity starting with the lowest-cost bidders.

Option 1 is ruled out because the IDRs may have different emissions profiles from one another. Bidders are expected to adjust their bid price to account for expected adders or subtracters, so bids should apply to specific IDRs. Option 2 allows QFs the same choice of IDR discussed above, but removes some of the ability to influence the price received. For reasons discussed above, this proposal is an improvement but does not ensure an optimal group of winners.

Option 3, the option preferred here, eliminates the opportunity to bid strategically. Each bid would be identified as applicable to a particular IDR. (For example, bidder 1 submits bids 1A and 1B, which would apply to IDR A and IDR B, respectively.)

When designating winners, in what order should the utility fill the IDRs? From an economic standpoint, the answer might be that the utility should first fill the capacity of the <u>least</u> cost-effective IDR and end with the capacity of the <u>most</u> cost-effective IDR. The parties should discuss whether this sequence is appropriate, given our strategic bidding concerns.

As each IDR is filled, the utility would designate lowest-cost bids as winners after eliminating bids from QFs that had already won. Per existing rules, the lowest losing bid on each IDR would set the price for that IDR.

2.2 Set-Asides

A set-aside is meant to ensure that a minimum level of renewable resources will enter the resource plan.[1/] There are many ways to address this issue, but this proposals boils them down to two: (1) restrict bidding on specified IDRs to renewable technologies; or, (2) allow all technologies to bid against all IDRs but establish rules to ensure that renewable QFs win a minimum amount of the available capacity.

Restricted bidding has potential problems similar to those discussed in the preceding section. The least-cost renewable QFs might bid only against set-aside IDRs, where their chances of winning and achieving high rents are maximized since no competition with fossil-fired QFs occurs. Also, because some renewable QFs actually may be competitive with fossil-fired QFs, the latter QFs could also realize higher prices through restricted bidding.

The second approach seems preferable. By allowing all technologies to bid against any IDR, competition would be maximized without losing renewable capacity so long as enough renewable QFs enter the auction to subscribe the set-aside fully.

This proposal chooses to fill the set-aside portion of the IDR first, based on the lowest cost renewables, followed by the all-technology portion, based on the lowest cost remaining bidders, regardless of technology type. The price awarded to the winners in

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1/ The assumption here is that renewable QFs bid sufficient capacity to at least fill the set-aside.

both the set-aside and all-technology portions would be the price of the lowest losing bidder in the all-technology portion of the IDR, unless this price is less than the price of any of the winning renewables in the set-aside portion. In that case, winners in the set-aside portion would get the price of the lowest losing renewable bidder.

Establishing the price paid to all winners as the lowest losing bidder in the all-technology portion of the IDR should prevent strategic bidding. The exception is necessary to ensure that a renewable winner does not receive less than what it bid.

3. Straddling the MW Limit

It is highly unlikely that each IDR will be filled perfectly in an auction. For example, the winning bidders against a 50 MW IDR may be bidder A (30 MW), followed by bidder B, whose bid is also for 30 MW. In effect, B's bid straddles the MW limit of the IDR.

The discussions and workshops should address whether the Commission's existing rules, approved in D.87-05-060 (24 CPUC 2d 253, 261), are appropriate in straddling situations for IDRs (or set-asides) with small MW limits. One issue might be whether a renewable QF whose capacity straddles the set-aside limit should be able to have the balance of its capacity considered for the all-technology portion of that IDR.

For convenience, the existing straddling rule is reproduced below from Edison's bidding protocol.

6.2 Last Capacity Increment

(a) Downsizing

If the last [contract] awarded results in an aggregate total Effective Capacity greater than 110% of the capacity of the Deferrable Resource..., then the last bidder shall be given 30 days to reduce the size of its project. Failure of the bidder to reduce

its project capacity to a level that will make the aggregate total Effective Capacity less than 110% of the capacity of the Deferrable Resource shall result in the rejection of its bid. Only one bidder will be given the opportunity to downsize its project. All other bids will be rejected.

(END OF ATTACHMENT 6)

ATTACHMENT 7

Additional Appearances

Protestant: Sharon Province, Attorney at Law, and Robert Sones, for ERC Environmental and Energy Services Company.

Interested Parties: Arlene L. Ichien and David Mundstock, Attorneys at Law, for California Energy Commission; Rives, Boley, Jones & Grey, by James C. Paine, for PacifiCorp dba Pacific Power & Light Company; Arthur S. Lujan, for San Diego Building and Construction Trades Council AFL-CIO; Bernardo R. Garcia, National Staff Representative, for Utility Workers Union of America, AFL-CIO; Messrs. Skadden, Arps, Slate, Meagher & Flom, by Steven F. Greenwald, Attorney at Law, for Chevron U.S.A., Inc.; Frank J. Mazanec, for State of California, Prison Industry Authority; Timothy S. O'Grady, for PG&E/Bechtel Generating Company; Jo Shaffer, for herself; Sue Vigars, for BHP Minerals International Inc.; and Michael H. Hyer, for Peabody Coal Company.

(END OF ATTACHMENT 7)

I.89-07-004
D.92-04-045

## Commissioner Patricia M. Eckert, Concurring:

I support the order today in this phase of the Biennial Resource Plan Update proceeding but write to express my deep concerns with respect to the order's adopted methodology for internalizing the costs of residual power plant emissions. First, I do not support the economic concept of internalizing residual power plant emissions by incorporating the emission values into the planning and/or acquisition phases of the process. Second, I fundamentally disagree with the order's adoption of an emission value for carbon.

I base my support for this order, however, on strictly adhering to California Public Utilities Code § 701.1(c), which mandates in part that "*the commission shall include a value for any costs and benefits to the environment, including air quality*," in evaluating resources for cost-effectiveness. The language of the statute clearly dictates that the Commission adopt a value greater than zero. I believe that good cause exists, at this time, for adopting a zero value for residual emissions.

### Internalizing Residual Emissions

The inference that there are unpriced externalities that lead to inefficient utility production choices simply because residual power plant emissions exist is flawed. This is the erroneous inference mandated by statute and embraced by our order. Residual emissions would exist even under conditions which completely and efficiently internalize the cost of emissions. Superimposing additional emission costs on top of the current costs of utility air quality compliance entails assessing the costs utilities have already incurred to internalize emissions. Assessing this level of cost provides a basis from which to evaluate whether additional expenditures are necessary to reduce power plant emissions. The Commission has not undertaken this evaluation, nor is it required to under the statute. Absent this assessment, however, I believe we may be placing additional costs onto ratepayers for benefits that do not exist.

An economically more attractive approach to value residual emissions is an emission trading scheme. Approaches such as those adopted under the federal Clean Air Act of 1990 for $SO_X$ emissions, and the recent action by the South Coast Air Quality Management District to move to an emission trading program I believe underscores the advantages this approach offers.

## Carbon Emissions

Public Utilities Code § 701.1(c) also mandates that any emission values that our Commission adopts must be consistent with those adopted by the California Energy Commission. The California Energy Commission adopted a value for carbon in ER-90. Our decision in this proceeding also adopts a value for carbon.

This troubles me. I am concerned because it is known that the scientific community is split on whether $CO_2$ emissions contribute to global climate change. Yet, our decision, albeit adhering to the letter of the statute, ascribes a value to carbon emissions now because owners of existing generation facilities in the future may be required to reduce carbon emissions if carbon is found to contribute to global climate change.

If, in the future, it is proven that carbon emissions do contribute to global climate change, I am similarly skeptical as to how much California's contribution to limiting only one of the so-called greenhouse gases will have any real impact globally. The potential magnitude of the problem is enormous and it requires national and international cooperation.

I don't believe that it is the public interest to force ratepayers to pay a $CO_2$ surcharge for electricity when ratepayers can have little confidence that we as Commissioners, or the scientific community, understand global climatological systems.

Even under § 701.1(c), I question the Commission's statutory authority to assign costs (values) where none can be ascertained or identified with respect to $CO_2$.

Patricia M. Eckert

April 22, 1992
San Francisco, CA

I.89-07-004
D.92-04-045

Commissioner John B. Ohanian, Concurring

Today's order adopts a resource plan for our utilities which will have major ramifications for California's ratepayers well into the next century. I am voting for this order because it adopts much of what I prefer to see in this plan. I must, however, express my reservation about two substantive issues.

First, we are not using the most current information available to the Commission. I recognize that there comes a point when one simply must close the record and make decisions. I am a proponent of that view. On the other hand, basing a decision in 1992 on a report issued in 1990, which in turn was based on data from the 1980s does not well serve the people of California.

My preference in this case would have been to reopen the record to receive updated information on resource need. If our plan adopts a resource need in excess of actual need, then the ratepayers of this state will suffer the consequences, and some of these consequences may last more than fifteen years.

Because timing is such an important factor in issuing our decisions I recommend that my colleagues schedule the next BRPU case to enable the Commission to use more current information if it is expected to be available.

I am relieved that we did adopt a more current gas price forecast. This act alone may save California ratepayers more than a hundred million dollars through the remainder of the century. We have also adopted non-uniform environmental values for generation sources. This will allow our utilities to access inexpensive purchased power from areas east and north of California which would other wise have been excluded to the

detriment of California. These changes were essential for my support for this order. Between them, these two modifications to the Proposed Decision make a substantial improvement from the Proposed Decision which merits support.

Second, I am troubled by the set aside program adopted in today's decision. The entire concept of a least cost resource plan is to minimize the long run costs of adding generation capacity. Yet, into this plan we inject a special class of uncompetitive producers who will be propped up by ratepayers in expectation that the technology may someday be valuable. I completely disagree with this part of the order.

We must recognize that this is a biennial process. If a resource is not competitive today because of some alleged cyclical low in alternative resource prices, will that resource be able to compete in two years when prices return to the "normal" level? Discussions of abnormal prices remind me of the old Soviet Union which could not feed itself because of seventy-five consecutive years of unusually bad weather. Reliance upon the "bad weather" reasoning instead of the truth eventually lead to the collapse of that nation.

Put another way, are we supposed to adopt a resource as part of the long-term plan in hopes that it will become competitve tomorrow? I hope not. We should select only those resources which can stand on their own merits in today's world.

Let me also point out that set aside programs for uncompetitive resources is contrary to my belief of allowing markets to determine outcomes where competition exists. This entire planning process is supposed to be about establishing a competitive framework where resources can bid against each other on the proverbial level playing field. A set aside program is nothing more than favoring a chosen few to prevail over the

utilities at the expense of ratepayers. Such subsidies are the bane of moving the utility industry toward efficiency.

Let me digress a bit into why the price of natural gas is a fine benchmark against which to compete without setting up artificial reasons to try to out-guess the market. It is my belief, and this has been stated elsewhere in print as well as by mouth, that resource prices tend to reflect all known market information about that resource. In the gas market there are an enormous number of well informed buyers and sellers of natural gas determining the price of that commodity. We can look to the futures market in New York, we can look at one and two year deals which have been struck by our jurisdictional utilities, one can look at most price forecasts done by non-industry groups, and we see that gas prices are not expected to rise precipitously in the near term. Certainly not before the next BRPU decision. The natural gas price is precisely the benchmark to use, without modification. If a resource believes that natural gas prices will rise precipitously, then let it bid with that in mind. It is one of the promises of non-utility power production that developers take the risk of development, not the ratepayers. Yet, it is upon these ratepayer hostages that uncompetitive resources are being foisted. I remain opposed to this concept and its inclusion in this order.

Much of my frustration with this process is not with my colleagues. We have worked dilligently to implement the statutes as they have been presented to us. Unfortunately, because of a lack of consistency in the statutes we find ourselves compelled to aid particular interests in this case while also trying to minimize the rate impacts to utility customers. In my opinion, the legislature could do California a great service by establishing a self-imposed moratorium on legislation intended to influence a process which has not yet digested the existing statutes.

In summary, I recommend that the Commission schedule its next BRPU decision in such a way as to incorporate updated resource information. Second, the Commission should not try to outguess the market by establishing set aside programs for resources which can't compete with the alternative supply source forecast. Finally, I wish to thank my colleagues for accomodating many of my views in this difficult and extremely complex proceeding.

John B. Ohanian

San Fransisco, California
April 22, 1992