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Decision 91-04-071 April 24, 1991

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ORIGINAL

Application of Pacific Gas and Electric Company (U 39 E) for a certificate of public convenience and necessity authorizing participation in California-Oregon Transmission Project.	Application 90-08-066 (Filed August 31, 1990)
In the Matter of the Application of Southern California Edison Company (U 338 E) for a certificate that the present and future convenience and necessity require or will require Edison to invest and participate in the construction and operation of applicant's share of a 500 kV AC transmission line starting at the California-Oregon border and going through Alameda, Colusa, Contra Costa, Glenn, Merced, Modoc, Sacramento, San Joaquin, Shasta, Siskiyou, Solano, Tehama, and Yolo Counties in California, known as the California-Oregon Transmission Project.	Application 90-08-067 (Filed August 31, 1990)
In the Matter of the Application of San Diego Gas & Electric Company (U 902 E) for a certificate that present and future public convenience and necessity require or will require SDG&E to participate in the construction and operation of a 500 kV transmission line from Southern Oregon along the existing Malin-Meridian 500 kV transmission line to central California near the Tesla Substation, known as the California-Oregon Transmission Project.	Application 90-09-001 (Filed September 4, 1990)

(See Appendix A for appearances.)

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GLOSSARY

A.	Application
AB	Assembly Bill
AC	Alternating Current
ALJ	Administrative Law Judge
BPA	Bonneville Power Administration
CACD	Commission Advisory and Compliance Division
CDWR	California Department of Water Resources
CEC	California Energy Commission
CEQA	California Environmental Quality Act
COTP	California-Oregon Transmission Project
CPC&N	Certificate of Public Convenience and Necessity
CPUC	California Public Utilities Commission
D.	Decision
DC	Direct current
DRA	Division of Ratepayer Advocates
DSI	Direct Service Industry
DSW	Desert Southwest
Edison	Southern California Edison Company
EHV	Extra High Voltage
EIR	Environmental Impact Report
EIS/EIR	Environmental Impact Statement/Environmental Impact Report
ER	Electricity Report
FERC	Federal Energy Regulatory Commission
gWh	Gigawatt/hour
I.	Order Instituting Investigation
IDU EIS	Intertie Development and Use EIS
IEP	Independent Energy Producers
IOUs	Investor-owned Utilities

GLOSSARY

kV	Kilovolt
LADWP	Los Angeles Department of Water and Power
MBF	Thousand Board Feet
MOU	Memorandum of Understanding
MTS	Midway Transmission Service
MW	Megawatts
NEPA	National Environmental Policy Act
NPV	Net Present Value
NPPC	Northwestern Power Planning Council
PG&E	Pacific Gas and Electric Company
PNW	Pacific Northwest
PR	Public Resources
Principles	Principles for Tesla-Midway Transmission Service
PROPP	Positive Resolution of Powerline Problems
PSD	Prevention of Significant Deterioration
PU	Public Utilities
QFs	Qualifying Facilities
SB	Senate Bill
SCAQMD	Southern California Air Quality Management District
SDG&E	San Diego Gas & Electric Company
SFAS	Statement of Financial Accounting Standards
SMUD	Sacramento Municipal Utility District
SONGS	San Onofre Nuclear Generating Station
SOT	South of Tesla
SOTR	South-of-Tesla Reinforcements
TANC	Transmission Agency of Northern California
TURN	Toward Utility Rate Normalization
UIS	Utility Interconnection Support
WAPA	Western Area Power Administration

OPINION

Summary

The California-Oregon Transmission Project (COTP) is an extra high voltage electric transmission line (EHV 500 kV) proposed for construction extending from the California-Oregon border to the existing 500 kV lines in the vicinity of Pacific Gas and Electric Company's Tesla substation in Alameda County. It involves a large number of co-participants, including the Transmission Agency of Northern California (TANC), the Western Area Power Administration (WAPA), several California cities, irrigation districts, California Department of Water Resources (CDWR), utility districts, and Pacific Gas and Electric Company (PG&E), the Southern California Edison Company (Edison), and San Diego Gas & Electric Company (SDG&E). COTP has a planned transfer capability of 1,600 megawatts (MW) with a scheduled operation date of December 1992. The estimated project cost is $414 million.

Applicants, PG&E, Edison, and SDG&E, (collectively the investor-owned utilities or IOUs), each seek a certificate of public convenience and necessity authorizing it to participate in COTP. We have concluded that the request must be denied. The Applicants have failed to demonstrate that the project will be cost effective under the economic and resources assumptions provided in the record of this proceeding. In these circumstances we are not convinced that there will be sufficient power available in the Pacific Northwest over the life of the project to support investor-owned utility participation and assure the financial integrity of the project.

Description of the Project

COTP is a joint participation project among TANC, WAPA, the cities of Anaheim, Azusa, Banning, Colton, Riverside, and Vernon, Edison, PG&E, and SDG&E, and CDWR, several irrigation and utility districts (see, Project Participants, Appendix B).

Throughout this opinion the participants other than the IOUs are sometimes referred to as the "munis." COTP entails construction of 339 miles of 500 kV alternating current (AC) transmission line and supporting facilities (see, map, Appendix C). COTP will (1) connect to a six-mile segment of 500 kV transmission line to be constructed by the Bonneville Power Administration (BPA), which will extend from the proposed new Captain Jack Substation in southern Oregon to the California-Oregon border, continue south for 142 miles, and interconnect at the proposed Olinda Substation near Redding, California; (2) upgrade WAPA's 230 kV lines to 500 kV for approximately 170 miles, from Redding to a point near Sacramento; (3) construct approximately 20 miles of new 500 kV transmission line from a point near Sacramento to the Tracy Substation; and (4) construct seven miles of new 500 kV line from Tracy to an intersection with the existing Tesla-Los Banos No. 2 Line. COTP will terminate at the Tesla Substation in eastern Alameda County. COTP has a planned transfer capability of 1,600 MW, with scheduled operation in December 1992. Construction of COTP by the current participants started in mid-1990. Financial arrangements for constructing COTP have been completed and $283 million of bonds have been issued and $250 million in commercial paper has been authorized. The total estimated project cost is $414 million.

The proposed COTP 500 kV AC line will add a third 500 kV AC transmission path between the Pacific Northwest (PNW) and California on a right-of-way that is separate from the two existing AC lines. It will be integrated with the existing Pacific Intertie facilities. The combined transmission capability to the PNW in 1993 with COTP will be 7,790 MW measured at the California-Oregon and Nevada-Oregon borders.

Procedural Background

By ALJ ruling, the three applications were consolidated into one proceeding and a prehearing conference was held September 19, 1990.

Various issues were raised during the first prehearing conference regarding both the scope of the issues in the proceeding and the schedule. As a result, the ALJ issued a procedural schedule and tentatively identified the issues to be heard and matters that would not be considered.

The ALJ set October 9, 1990 as the date for submission of protests in accordance with Article 2.5 of the California Public Utilities Commission's (CPUC) Rules of Practice and Procedure. Protests were received from Division of Ratepayer Advocates (DRA), Independent Energy Producers (IEP), Southern California Gas Company, Toward Utility Rate Normalization (TURN), Gregory H. Bowers, and Positive Resolution of Powerline Problems (PROPP). The ALJ further ruled that these tentative findings would be made final at the prehearing conference on October 16, 1990, convened for the specific purpose of setting the issues to be heard and determining the relevance of protests.

Hearings commenced on November 26, 1990 and concluded December 13, 1990. Briefs were filed January 11, 1991.

DRA contends, and we agree, that at the threshold we must decide whether the presiding ALJ was correct in his ruling to strike substantial portions of DRA's and IEP's testimony.

The stricken testimony concerns two issues: (1) incorporation into the economic cost-effectiveness analysis of the costs of changes in residual emissions of air pollutants associated with COTP, and (2) analysis of the costs of a "no project" case which assumes COTP is not built.

A. <u>The Residual Air Pollutant Cost Issue</u>

In its cost-effectiveness analysis, DRA included a detailed review of the costs and benefits associated with the Applicants' participation in COTP. DRA also analyzed the changes in residual emissions of criteria air pollutants in three case scenarios: a no-COTP, a muni-only COTP, and a full participation COTP cases. IEP included similar analyses in its prepared testimony. These analyses purported to show that IOU participation in COTP would result in significant increases in the societal costs associated with such pollution. DRA also purported to show that if these economic externalities were captured in the analysis, it would reduce the cost-effectiveness of COTP compared to alternate sources of energy. Edison filed separate motions to strike both DRA's and IEP's testimony regarding the amount and value of residual environmental effects of COTP. The ALJ granted both motions.

B. <u>The No-COTP Case</u>

DRA routinely performs a "no-project" analysis in reviewing CPC&N applications to create a baseline against which the economic benefits and costs of the proposed project can be measured. Without a no-project analysis, it is often analytically impossible to tell whether or not a proposed project will have net benefits. Both DRA and the Applicants performed no-project analyses of COTP assuming that COTP would not be built. DRA's analysis concluded that participation in COTP by both PG&E and Edison would result in net costs to ratepayers compared to their not participating.

DRA and the IOUs also prepared analyses comparing a full participation scenario to a muni-only COTP scenario (a case where the municipal utility participants in COTP build the line without IOU participation). However, the IOUs chose to compare their participation <u>only</u> against the muni-only case. Edison then moved to strike the no-project scenario. The ALJ denied the motion stating that he would take testimony on the issue of whether COTP would be built regardless of the IOUs' participation. After hearing testimony the ALJ made his finding that COTP would be built regardless of the IOUs' participation, and struck the testimony concerning the no-project scenario.

Residual Air Emissions

"Residual emissions" are those emissions of air pollutants created or displaced by an energy project assuming all regulatory standards have been met. Even when a power plant is complying with state and federal air quality regulations (and CEQA requirements, if any), it still will emit air pollutants. Some plants and projects emit more pollutants and some less. The jargon "valuing residual air emissions" is a technical way of reflecting the relative dirtiness or cleanness of various competing sources of electricity.

The basic principle behind residual air emission values is described by the California Energy Commission (CEC) in its 1990 Electricity Report (ER):

> The theory of this approach is that even after an electric power plant has met all applicable air quality rules, such as BACT [Best Available Control Technology] and offset requirements, the plant's remaining (residual) emissions continue to impose costs on society. If the utility can reduce those residual emissions, the reduction provides a benefit to society. Thus, if a new plant can displace an existing plant's emissions, the "benefit" derived from that reduction should be accounted for when determining the cost-effectiveness of the new resource.

In its ER-90 report, the CEC approved specific residual emission values as appropriate for Edison's resource planning:

Table 1

The CEC's ER-90 Residual Emissions Values (1987$/Ton) (From Exhibit 155 at 5-9)

Pollutant[1]	In-state	Out-of-state
NOx	$11,600	$2,700
SOx	11,500	1,000
ROG	3,300	300
PM10	7,800	800
Carbon	26	26

IEP used the CEC's values in its stricken testimony. DRA used different values.

The amount of emissions in tons is an output of the production cost simulations used in resource planning. In the case of ER-90, the CEC developed NOx numbers as an output from the ELFIN production cost model. For this COTP proceeding, DRA used the SERASYM and SERAM-2 production cost models for both the economic analysis and the NOx estimates.

Motion to Strike DRA's and IEP's Testimony on Residual Emissions Costs

A. Positions of the Parties

DRA and IEP contend that the ALJ erred in granting Edison's motions to strike both DRA's and IEP's testimony on residual air quality costs and benefits. According to DRA, the ALJ rulings violate Public Utilities Code Section 701.1, and are inconsistent with Edison's position in other proceedings, the Commission's current policies, and the CEC's recognition of

1 NOx and SOx refer to nitrogen oxides and sulfur oxides, respectively. ROG refers to "reactive organic gases." PM10 refers to particulate matter less than 10 microns in diameter (dust). Carbon refers to carbon generally; the main source of carbon in energy emissions is carbon dioxide which is included not because it is a criteria pollutant, but because it is the principal greenhouse gas.

residual environmental costs and benefits in ER-90 and other proceedings.

Applicants contend that the ALJ's rulings were proper because costs and benefits associated with air quality are environmental issues which should have been raised during the EIR/EIS process, and that to allow these issues to be raised in this proceeding would be contrary to CEQA. In addition, PG&E argues that application of Public Utilities Code Section 701.1 to this case would constitute retroactive application of the statute and would be contrary to the legislature's intent. Finally, Edison and CEC assert that there is no legislative mandate to apply Section 701.1 to this proceeding.

B. Discussion

There are two distinct arguments concerning the application of Section 701.1 in this proceeding. The first is the contention that we are precluded by law. The second admits the Commission's legal authority to apply Section 701.1 but asserts that such application would not be prudent. We reject both.

Public Utilities Code Section 701.1 was approved by the Governor on September 28, 1990, prior to the commencement of hearing on November 26. It became effective on January 1, 1991, after the close of the evidentiary record on December 13, 1990.[2] The legislation adopting Public Utilities Code Section 701.1 also added Section 25000.1 to the Public Resources Code. The two sections require electric and gas utilities to make it a principal goal to minimize the cost to society of reliable energy services, to improve the environment, and to encourage diversity of energy resources. The legislation also encourages utilities to seek to exploit all practicable, cost effective, and reliable conservation

2 Deering's 1990 Cal.Av.Leg.Serv., Ch. 1475, AB 3995 (1990 Vol. 7, pp. 6164-6165).

and efficiency improvements. Lastly, the legislation requires the Commission and the CEC, in determining cost effectiveness of energy resources, to include a value for any costs and benefits to the environment, including air quality.[3]

As is evident from the chronology, the legislature was conducting the public business on a timetable which partially paralleled the processing of the applications in the instant matter. We are now asked to decide whether those applications may be subjected to the requirements of a statute which was enacted but had not achieved an effective date prior to the conclusion of the evidentiary submission without offense to notions of fundamental fairness. The issue is important. It has arisen on previous occasions and is likely to be encountered in the future. In our view, it cannot be answered with a categorical "yes" or an unconditional "no."

A negative answer would be appropriate if legislation altered the requirements which an applicant would be required to establish and intruded upon the administrative proceeding at a point in time in which the applicant was deprived of an opportunity to meet that burden. In such circumstances, due process would require that the decision maker either deem the applicant exempt from such standards or reopen the record so as to accord the parties an opportunity to satisfy the newly articulated burden. On

3 The ALJ excluded the DRA's and IEP's submissions relating to residual environmental costs and benefits because the issues raised were "environmental" which should have been considered in the EIR/EIS prepared by TANC and WAPA. (Proposed Decision at pp. 13-21.) Such a view does not accord with our understanding. There are fundamental differences between the analysis of environmental effects performed pursuant to CEQA and the cost-benefit analysis required by Section 701.1. While nothing would prevent the analysis required under Section 701.1 from being undertaken as part of the environmental review process, Section 701.1 imposes requirements distinct from those of CEQA.

the other hand, if the impact of the legislation did not alter the nature of the showing required of the applicant, or merely directed the decision maker to accord revised weight to matters already in the record, the applicant could not complain that the public business was executed according to the most recently formulated articulation of the public interest.

Such a view is in accord with decisions of our Supreme Court. In Santa Monica Pines, Ltd. v. Rent Control Board, 35 Cal. 3d 858 (1984), the court deemed the matter governed by the concept of equitable estoppel. Marshalling precedent the court declared:

> This is a principle of equitable estoppel which may be applied against the government where justice and fairness require it...
>
> An equitable estoppel requiring the government to exempt a land use from a subsequently imposed regulation must include (1) a promise such as that implied by a building permit that the proposed use will not be prohibited by a class of restrictions that includes the regulation in question and (2) reasonable reliance on the promise by the promisee to the promisee's detriment... Appellants here cannot have a vested right unless and until both of these elements of estoppel against the government are established.
>
> Id., at 866-67.[4]

The applicants have established neither of the criteria demanded by the Santa Monica Pines court. The record is devoid of any express or implied promise that prior Commission criteria or

4 For a recent case illustrating an application of this equitable estoppel doctrine see, Hock Investment Company, Inc. v. City and County of San Francisco, 215 Cal. App. 3d 438 (1989). Estoppel in the face of a vested right is also extensively discussed in Spindler Realty Corp. v. Monning, 243 Cal. App. 2d 255, 263-69 (1966).

Section 701.1 would not be utilized in determining whether a CPC&N would issue. The consideration of costs and benefits of residual environmental effects mandated by Section 701.1 could not possibly have taken the applicants by surprise. Indeed, the statute merely codified established Commission practice. Prominent among the recent examples of such an analysis are the reception of the application for the Devers-Palo Verde II transmission line (A.85-12-012) and the Biennial Resources Plan Update proceeding (Update, I.89-07-004). Nor were applicants denied an opportunity to meet the requirements of Section 701.1 and Commission precedent during the course of the evidentiary proceeding before the ALJ. To the contrary, they were confronted by evidentiary submissions on these very points; submissions which they actively sought to exclude.[5]

The argument that a permissible utilization of Section 701.1 would be imprudent is quickly dispatched. The content of that statute plainly embodies the values and goals first articulated in Commission proceedings and thereafter embraced by the elected representatives of the people of California. No provision of the statute exempts pending applications, and the applicants have cited nothing in the legislative history which would warrant the conclusion that the legislature intended that

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5 We also note that the California Energy Commission has recognized and embraced the relevance of these issues to electric resource planning in its own ER-90 proceeding. The CEC urged the Commission to apply ER-90 in Phase 1B of the Update. We are thus perplexed at the CEC's inconsistent submission before our ALJ that an application of the approach it espoused in ER-90 to this matter "would be extremely premature..." (CEC Concurrent Brief, p. 23.) In essence the CEC is urging the Commission to ignore ER-90, a well considered work product characterized by the Independent Energy Producers as "the abandoned child of the CEC." (IEP Comments, p. 5) This we decline to do.

these matters be stayed with respect to parties who could demonstrate no prejudice by their application.

Although the CPUC finds that the ALJ erred in excluding DRA's and IEP's testimony on these issues, it cannot now include that testimony in the record because of the time constraints of the Permit Streamlining Act. (Gov. Code §§ 65920 et seq.) The motion to strike was granted prior to any cross-examination on the testimony. We would have to reopen hearings in order to admit the testimony. Further hearings in this proceeding are not possible if the Commission is to issue a final decision prior to the "deemed approved" deadline. (Gov. Code § 65952.)

The burden of proof justifying the issuance of a certificate of public convenience and necessity (CPC&N) is clearly on the Applicants. (See, e.g., Re San Diego Gas and Electric Co. (1988) 27 Cal. P.U.C. 407, 410.) As part of that showing, Applicants must prove that the project is cost effective. (Pub. Util. Code §§ 701.1 and 1102.) Because there is no record on which to base a determination of residual environmental costs and benefits, we conclude that the Applicants have not carried their burden of proof on the cost effectiveness of the project under Public Utilities Code Sections 701.1 and 1102.

In making their motion to strike, Applicants assumed the risk that the ALJ ruling would be reversed. When the ALJ granted Applicants' motion, he warned the Applicants that the Commission could reverse the ruling and reopen the case. Asked whether the Applicants were willing to take that risk, attorneys for Edison and PG&E answered that they were. (Tr. Vol. 8, pp. 902-903.) The Commission cannot now reopen hearings. We are left with an incomplete record, making it impossible for the Commission to comply with Section 701.1. We therefore find that Applicants have failed to make the requisite showing under Section 701.1.

<u>Will COTP Be Built If the Applicants Do Not Participate?</u>

At the prehearing conference Applicants moved to strike DRA's prepared testimony concerning the no-project scenario on the ground that COTP would be built by the municipal participants regardless of the participation of the Applicants. Eliminating the no-project scenario would also eliminate the issue of need for the project (as distinct from need for the Applicants' participation in the project). The ALJ held that the issue of whether COTP would be built if the Applicants do not participate would be ruled on only after evidence was taken and would be heard first. Both Applicants and DRA presented testimony on this issue.

A. <u>Position of the Parties</u>

<u>Applicants</u>

On behalf of Applicants, the Executive Director of TANC testified that COTP will be built irrespective of the participation of the Applicants. He testified that TANC had completed financing arrangements for COTP and that construction had begun. $283 million in revenue bonds has been issued and $250 million in commercial paper has been authorized. He said that TANC's financing arrangements were structured such that COTP can be completed even if WAPA and TANC are ultimately the only participants in the project.

<u>DRA</u>

DRA's witness asserted that there was a likelihood that COTP would not be completed without IOU participation. He admitted, however, that the probability associated with DRA's contention was difficult for DRA to measure. He said that PG&E and TANC could not reach agreement regarding interconnection necessary to afford a scheduling path to the service area to each TANC participant. If agreements are not reached, the project could be cancelled.

On cross-examination he admitted that he did not know what agreements and what physical interconnections existed between PG&E and other TANC members. He testified that he thought there was uncertainty over whether TANC has the financial resources to finance COTP should the IOUs not participate. He said that TANC may not be able to obtain long-term financing for the IOU shares represented by the $250 million in commercial paper, and that the Sacramento Municipal Utility District (SMUD) is financially unstable. As TANC's largest member, DRA's witness said, SMUD could bring about a "death spiral" through its efforts to eliminate the deficit resulting from the write-off of Rancho Seco.

TANC's Executive Director disputed each of DRA's arguments, pointing out that since TANC's revenue bonds were insured and issued on the basis that TANC would finance the entire COTP if necessary, there was clear proof of TANC's financing ability. He testified that TANC had begun construction, had financing in place to complete the project, and was in the process of negotiating suitable arrangements with PG&E to provide the necessary transmission services whether or not PG&E is a participant.

B. Discussion

At the conclusion of the testimony on this issue, the ALJ stated that he was persuaded by the evidence that COTP will be built by the municipalities even if the IOUs do not participate. We agree with the ALJ. The evidence is persuasive. These are the uncontroverted facts: (1) project construction began in June 1990; (2) TANC has issued $283 million in tax exempt revenue bonds; and (3) TANC has authorized the issuance of up to $250 million in commercial paper to finance the construction of COTP.

We are well aware that no one can predict future events with certainty. We must decide cases based on the evidence presented. Certainty is not possible; it is the weight of the evidence that counts and the evidence is convincing that COTP will be built regardless of the participation of Applicants.

Our conclusion that COTP will be built even if the IOU's do not participate does not necessarily mean that the evidence regarding the no-project alternative should have been excluded. It would have been appropriate to admit the evidence in order to provide a baseline for cost comparison. However, since we do not find that this evidence is crucial to our decision, we will not address the ALJ's ruling.

Pacific Northwest Capacity Availability

Integral to our determination of the need for IOU participation in COTP is a determination of the availability of PNW capacity. Surely if we are not confident that capacity is available, we should not authorize utility participation in a project whose cost effectiveness is dependent on capacity benefits.[6] These capacity benefits are based on the assumption that Applicants will purchase capacity over COTP from the PNW, permitting them to defer or eliminate planned generation projects.

A. Positions of the Parties

Applicants

The Applicants argue that there is ample PNW capacity. They state that the Joint Study based the availability of PNW capacity on conservative assumptions and that there would be more than sufficient capacity to fill both the existing interties and the COTP.[7] With respect to energy, the Applicants claim the

6 In its application, PG&E claimed $35 million in capacity benefits (PG&E Concurrent Brief, p. 40), Edison claimed $152.6 million stand-alone and $242.7 million merged in capacity benefits (Edison Concurrent Brief, p. 37) and SDG&E claimed $3.57 million in capacity benefits (SDG&E Concurrent Brief, p. 7).

7 Edison Concurrent Brief, p. 26; PG&E Concurrent Brief, p. 48.

Joint Study chose to use a reasonable forecast between the medium-low and medium-high forecasts of the NPPC.

DRA

Since construction of COTP was conceived, DRA notes, the IOU's need for additional transmission capacity to the PNW has decreased. Upgrades to the existing Intertie have increased the IOU's firm entitlements to capacity by more than participation in COTP would. Exchange agreements have also increased IOU capacity rights. DRA argues that since COTP was originally conceived in 1984, the availability of PNW power has decreased. It also argues that price savings associated with PNW energy have decreased. These trends, DRA states, are likely to continue.[8]

IEP

IEP states that the Applicants seriously overestimated capacity availability from the PNW so utility capacity benefits should be significantly discounted. IEP points out what it believes to be several omissions and shortcomings in Applicants showing:

- o Applicants assume the Northwest's aluminum industry would be interrupted to supply power to California;
- o Applicants assume a 66% capacity factor for new Northwest resources, adopting a BPA assumption over an 80-87% capacity factor applied by NPPC;
- o Applicants assume new Northwest resources would not require any reserve margin;
- o Applicants assume no line losses.

8 See Appendix D for abbreviated DRA arguments excerpted from DRA Concurrent Brief.

Once IEP makes its adjustments to Applicants' showing, the figures indicate that no capacity will be available to the IOUs in the long term over COTP.[9]

IEP discusses two qualitative issues relating to the estimate of available capacity. It states that Applicants assume that none of the summer capacity Applicants claim is available will be used by California's competitors in the Desert Southwest. IEP also believes that Applicants err in ignoring the Northwest's growing reliance on California winter energy and the impact of that reliance on summer capacity available for sale by the Northwest to California, thus increasing the uncertainty of the IOU's capacity availability numbers.

<u>Bowers</u>

Mr. Bowers, an engineer, also challenged the Joint Study's conclusion that there would be more than sufficient capacity available to fill COTP, as well as the existing interties, over the life of the project. He challenged the Joint Study on the same grounds as IEP. He also argued that the Applicants' analysis erred in several other ways by:

- including resources not available during summer;
- applying an incorrect availability factor to large coal plants;
- assuming average weather conditions in the northwest; and,
- omitting plant maintenance.

9 See Opening Brief of the Independent Energy Producers Association, p. 8, for quantitative analysis.

In his opinion there will be 2497 MW to 3921 MW of surplus capacity available in the Northwest in 2009.

B. Discussion

We are convinced by the testimony of DRA, IEP and Bowers that the Applicants have overstated PNW capacity benefits. IEP and Bowers note several deficiencies and omissions in the Applicants testimony regarding PNW capacity availability. When capacity numbers are adjusted for these factors, they clearly indicate there will not be enough surplus capacity available for IOU COTP participants. We make the following adjustments to the Applicants Joint Study analysis for September of 2009:

September 2009 Surplus Per Applicants:	7,469-8,248 MW[10]
Adjustments (subtractions from available capacity)	
No Interruption of DSI Before CA	-1,279 MW[11]
Nonexportable Additions	- 400 MW[12]
Maintenance Reserves	- 500 MW[13]
Transmission Losses	- 420 MW[14]
Total Adjustments	2,599 MW
Capacity Remaining After Adjustments	4,870-5,649 MW
Firm Capacity of Existing Lines	5,680 MW[15]
Less Unused Portion of LADWP	716 MW
Existing Line Used for Capacity	4,964 MW
Surplus Capacity Available for COTP	0-685 MW
Municipal Share of COTP Firm Capacity	748 MW[16]
Capacity Available for the IOUs	0 MW

Therefore, while we find PNW capacity available, we do not find enough available to support IOU participation in the project.

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10 Exhibit 9, p. C-V-17.

11 Opening Brief of IEP, p. 8.

12 Bowers.

13 The analysis of reserve margin offered by IEP is more precise than Bowers'. It estimates the reserve margin based on the margins for each potential resource. Therefore, we will adopt the adjustment procedure used by IEP. However, since we do not support IEP's use of a higher capacity factor, the amount of maintenance reserve should be roughly 500 MW.

14 Bowers.

15 7,180 minus 1,500 MW firm COTP (Exhibit 9, p. C-V-17).

16 TANC and the Southern City owners of COTP own 49.8% of COTP (Exhibit 9, p. C-II-41) or 748 of the 1500 MW of firm capacity.

Cost-Benefit Analysis

The three Applicants and DRA presented cost-benefit analyses to determine if it is economically feasible for the IOUs to participate in COTP. DRA made its analysis under varying assumptions: (1) that COTP would not be built without IOU participation, (2) that COTP would be built without IOU participation, and (3) that out-of-state emission costs should be included under assumptions 1 and 2. Because of the ruling which excluded testimony regarding out-of-state emissions and the time constraint we face under the Permit Streamlining Act, our discussion is necessarily limited. Two important aspects of the cost effectiveness analysis in the record concern whether CDWR and SMUD will have to return 500 MW of PNW capacity to the IOUs in 2005 and whether the cost of south of Tesla reinforcements should be included in the analyses. Because these two items play such an important part in DRA's analysis, they will be considered separately.

A. South of Tesla Issue

The termination point of COTP is near PG&E's Tesla Substation in Northern California. To bring COTP power to Southern California, PG&E must deliver it to its Midway Substation about 200 miles south of Tesla. In order to provide firm transmission service to customers in Southern California, certain upgrades must be made in PG&E's transmission system at the time COTP is built. These upgrades are known as the "Initial Reinforcements," and will cost approximately $12 million. No one disputes the need, nor the costs, nor the cost allocation of the Initial Reinforcements.

In addition to the Initial Reinforcements, the parties have identified the potential need for increased transmission capacity between Tesla and Midway. The provision of this transmission capacity will result in costs to PG&E, either by (a) requiring PG&E to operate some of its plants in a noneconomic manner ("mitigation") to get around transmission constraints in the

San Joaquin Valley, or (b) to make significant capital additions to its transmission system between Tesla and Midway substations, or both.

DRA assumed that the Los Banos-Gates line would be built in 2008 as a proxy for actions PG&E would have to take. The Applicants assume zero additional costs for any South of Tesla mitigation or construction during the entire 40-year study period. The construction of the Los Banos-Gates line, or its surrogate, is referred to as the South-of-Tesla Reinforcements (SOTR).

DRA's brief frames the SOTR issues as follows: (1) when will PG&E have to begin dispatching its plants in an uneconomic fashion to avoid curtailing power deliveries of COTP power to TANC and Southern California utilities, (2) when will it become less expensive for PG&E and the Southern California utilities to make further capital additions than to continue the uneconomic dispatch of its system, (3) how will the costs of these additions be allocated between PG&E and other COTP participants, and (4) are these costs properly considered part of COTP.

Addressing the fourth issue initially, DRA, TURN, and IEP all argue that the costs of the SOTR should be included in a cost-effectiveness analysis of the COTP project costs. The Applicants, on the other hand, argue that it is entirely appropriate not to include these costs in their cost-effectiveness analyses given their view of the speculative nature of the need for SOTR. However, PG&E in its first application for COTP included the costs of SOTR. (TR V.9, p. 1062: Weatherwax/DRA; Ex. 141.) In this 1987 application, PG&E stated that Los Banos-Gates may be needed in the mid- to late 1990s at a cost of $169 million. (Ex. 141 at C-13).

To justify its latest conclusion that the SOTR costs can be excluded from the COTP analysis, PG&E did a load flow study. This study contained two major changes in assumptions from PG&E's 1987 application. (TR V.5, pp. 578-79: Morris/PG&E). First, where the prior application had assumed that both Diablo Canyon units could be shut down simultaneously, this study assumed that one Diablo Canyon unit operated at all times. (Id.) Second, PG&E assumed that the contract demands of the entities entitled to service on its southern system occurred on a non-simultaneous basis. In its 1987 application, PG&E had assumed that all contracting entities would demand transmission service at the same time. (Id.) PG&E's witness agreed that both of these changes reflect less conservative assumptions regarding the need for SOTR. (TR V.5, pp. 581, 583-84: Morris/PG&E.)

Further, in response to TURN's data request, PG&E refused to commit that it would not seek to recover SOTR costs before 2005. (Ex. 165, p. 24, App. C.) Finally, in response to another of TURN's data requests, PG&E stated that SOTR costs are linked to the construction of COTP. (Ex. 165, App. C.) We agree with IEP that the refusal of the utilities to take any measure of shareholder responsibility for their estimate of zero SOTR costs strongly suggests that their position that no SOTR costs are required is simply not credible.

There is a risk that should SOTR become necessary solely because of the use of COTP, the combined cost of COTP plus SOTR, if considered today, would make COTP uneconomic. This is a risk that the Applicants are clearly unwilling to take and one which this Commission is unwilling for ratepayers to assume. As such, we agree with DRA, TURN, and IEP that the SOTR costs are properly considered part of COTP. Deferring consideration of SOTR costs until a subsequent CPC&N proceeding fails to protect ratepayers and is nothing more than "a form or regulatory incrementalism" where each piece of a project is analyzed assuming that the other part is already built. (TR V.9, pp. 1069-70: Weatherwax/DRA.)

We now turn to the questions of the magnitude and timing of SOTR costs. DRA's testimony assumed the Los Banos-Gates line would serve as a proxy for actions PG&E would have to take. DRA assumed that the line would go into service in 2008 at a cost of approximately $118 million in 1993$. In light of PG&E's previous testimony in this matter, DRA's timing assumption appears conservative. As well, DRA's cost assumption is consistent with other previous estimates of the project's cost. As such, we find that the inclusion of the Los Banos-Gates line in 2008 at a cost of $118 million in 1993$ is a reasonable proxy for additional reinforcement actions PG&E must undertake because of COTP's construction. In terms of allocation of these costs, only PG&E, TANC and Edison have agreed to pay for this COTP-related segment if it is determined to be required. For purposes of determining the cost-effectiveness of IOU participation in COTP we will adopt DRA's allocation of $40.9 million in costs to PG&E and $33.1 million to Edison.

B. The CDWR and SMUD Contracts

In August 1967, PG&E, Edison, and SDG&E entered into an EHV contract with SMUD to provide SMUD with 200 MW of transmission service on the Pacific AC Intertie. The contract states that it "shall continue in effect until January 1, 2005." (Ex. 57) On the same day that they signed the SMUD contract, PG&E, Edison, and SDG&E entered into a similar contract with CDWR to provide CDWR with 300 MW of transmission service on the Pacific AC Intertie. That contract also states that it "shall continue in effect until January 1, 2005." (Ex. 56) These layoffs are expected to continue until 2005. Both the Applicants and DRA have performed their analyses recognizing that SMUD and CDWR will continue to use this transmission service until 2005. The parties differ in that DRA accepts the contracts at their word - that they expire in 2005, whereas each of the Applicants assumes that the contracts will be continued beyond 2005.

1. Positions of the Parties

Applicants

In December 1984, the Applicants and SMUD amended the 1967 SMUD EHV contract. The critical section of this amendment states that upon the three IOUs receiving CPUC approval for participation in COTP, all four parties to the contract will amend the contract to extend the term of the contract (and thereby the IOUs' 200 MW of transmission service to SMUD) "for the useful life of the existing Intertie."

The COTP MOU (Ex. 55) provides that if PG&E gets satisfactory CPUC approval to participate in COTP, COTP is built, and CDWR executes the project participation agreement, then the terms of the 1967 EHV contract between CDWR, PG&E, Edison, and SDG&E "shall be extended for the useful life of the existing AC Intertie."

The IOUs' base cases assume that there would be no recapture of the existing 500 MW of Pacific Intertie EHV entitlements from CDWR and SMUD. This assumption is based on the uncertainty that recapture will occur, and on the unknown impact of regulatory and political conditions 15 years in the future. Here, both CDWR and SMUD submitted evidence affirming their intent to extend their intertie contract. This evidence demonstrates that the Applicants cannot terminate these entitlements without FERC approval.

<u>DRA</u>

DRA admits no surprise that CDWR and SMUD will want to extend the intertie contracts beyond the year 2005, since the service is virtually free. DRA wonders, however, why the IOUs do not actively oppose extension of these contracts. DRA notes that, in contrast to a new capital investment such as COTP, the current transmission lines are heavily depreciated and yield little return to shareholders. This gives the IOUs little incentive to end the contracts. DRA argues that, without IOU participation in COTP, the munis would be rich in transmission capacity (1,500 MW on COTP alone). Thus, DRA believes, the munis will have trouble convincing FERC in 2005 to prevent termination of the contracts.

2. Discussion

We find DRA's arguments persuasive. The potential ability of the IOUs to influence the outcome of a FERC proceeding should not be ignored. In 2005, it may be prudent for these utilities to let the contracts expire and to use the transmission capacity to meet their own loads. We agree that a muni-only COTP, on the other hand, could result in munis rich in transmission capacity. Therefore, there is a significant potential for FERC to terminate the contracts.

Benefits Which are Difficult to Quantify

A. Position of the Parties

CEC and Applicants

The IOUs state that participating in COTP will fill their needs in many ways:

- COTP will furnish them with increased access to economic, surplus power;
- COTP will permit more efficient use of resources by allowing increased regional power transfers allowing greater coordination and flexibility in meeting the needs of both California and the Northwest using existing resources;
- COTP could give the IOUs the opportunity for greater access to Canadian power resources;
- COTP meets the IOUs' needs for dispatchable resources since Northwest imports can be scheduled to best meet their loads; and,
- COTP will provide the IOUs with additional load-shaping capabilities through peaking capacity and exchange transactions enabling them to import more economy energy during high cost on-peak periods.

CEC claims there are other benefits which cannot be quantified, but which are nevertheless significant enough to justify full participation in COTP regardless of economic benefits. These strategic benefits include:

- the value of cooperation among IOUs and municipal utilities upon successful implementation of the MOU;
- the ability of the participants to maintain a share of the total Pacific Intertie capacity that is roughly proportional to the size of the loads they serve;
- the strong possibility that the static assumptions upon which the cost-benefit studies presented in this case have been based are too conservative, thus artificially reducing the apparent value of IOU participation to the IOU ratepayers; and
- the value that full participation has in furthering the goals the California Legislature as established by Senate Bill (SB) 2431 (1988) (Garamendi).[17]

<u>DRA and IEP</u>

DRA claims that CEC's strategic benefits are illusory. The DRA Concurrent Brief refutes point-by-point the "strategic benefits" claimed by the CEC (pp. 53-56). DRA also notes that many of the strategic benefits of COTP would be achieved even in a muni-only COTP. Further, DRA argues, many of the strategic benefits

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17 SB 2431, Chapter 1457 (1988) states:

> ". . . establishing a high-voltage electricity transmission system capable of facilitating bulk power transactions for both firm and nonfirm energy demand, accommodating the development of alternative power supplies within the state, ensuring access to regions outside the state having surplus power available, and reliably and efficiently supplying existing and projected load growth, are vital to the future economic and social well being of California."

claimed by CEC accrue to non-IOU ratepayers. DRA concludes that most of the strategic benefits alluded to will be realized in a muni-only COTP, and do not require IOU participation. DRA also believes that benefits potentially accruing to muni ratepayers are an insufficient justification for IOU ratepayers to bare the substantial cost burden of COTP participation. IEP contends that the CEC's strategic benefits are one-sided and unsupported (Concurrent Brief, pp. 30-32).

B. Discussion

We agree with DRA and IEP that the CEC arguments are without merit. We are not persuaded that equity participation in COTP is necessary to obtain for ratepayers the benefits the IOUs claim. We are surprised the CEC would sponsor testimony ignoring many of its own findings in the ER-90 only to put forward arguments lacking in substantiation. In particular, we note the strong CEC support for the assignment of economic values to changes in residual emissions of the major air pollutants associated with electricity generation (in-state and out-of-state) (Ex. 155, p. 5-9). This contrasts with the CEC's testimony in this proceeding that makes no reference to residual air emissions. Further, the CEC remained silent when Edison moved to strike expert witness testimony based on the CEC's ER-90.

The CEC claims IOU participation in COTP will increase cooperation between munis and IOUs, but many of the COTP agreements have yet to be negotiated. Contrary to an increase in cooperation, the Project Development Agreement has lapsed and has not been renegotiated. The CEC claims as a benefit the ability of the COTP participants to maintain a share of PNW capacity in proportion to the size of the loads they serve (Ex. 153, p. 10). But the current Intertie loads are not proportional to the loads they serve. A full participation COTP would not reapportion Intertie capacity according to load. We are not persuaded by the CEC arguments.

Cost Effectiveness of IOU Participation in COTP

The Commission is sensitive to the need to coordinate the cost-effectiveness analysis in this proceeding with the policies the Commission has established in the Update proceeding. The Commission has long sought as a policy goal the creation of a "level playing field" on which IOUs and QFs would compete to build the least cost new generation. The playing field has been the Update proceeding. Although COTP is being evaluated outside the Update proceeding, we have attempted to be consistent, to the extent possible, with the assumptions used in our cost-effectiveness analysis here.

DRA's numbers provide the most complete and consistent analysis and incorporate the following: (1) transmission-loss protocols used by the IOUs for the existing Pacific Intertie system,[18] (2) Northwest capacity and energy availability, (3) the South of Tesla Reinforcement costs, (4) the Intertie layoffs by SMUD and CDWR in 2005, and (5) the QF bidding adjustment for capacity benefits resulting from the Update proceeding. However, DRA in its analysis does not incorporate a number of adjustments raised by IEP based on the CEC's most recent Electricity Report, ER-90. IEP raised a number of concerns regarding the inconsistency in both the Applicant's and DRA's analysis with respect to the ER-90 assumptions. (Ex. 159 and 160, and IEP's Concurrent Brief, pp. 11-15.) In its brief DRA noted that it believes the IEP's adjustments are appropriate. (DRA's Concurrent Brief, p. 35.) We are also convinced that these adjustments are appropriate and have attempted to adjust DRA's analysis to make it consistent, to the extent possible, with ER-90 and the Update proceeding.

18 See DRA's discussion in appendix N in Volume II of its report on the cost-effectiveness of COTP, Ex. 6.

We have used DRA's analysis for each utility under the scenario comparing the costs and benefits of a muni-only COTP versus full muni and IOU participation in COTP. To this cost/benefit analysis, we make the necessary changes suggested by IEP to bring the numbers into consistency with the Update proceeding.

A. Edison

In examining the cost effectiveness of Edison's participation in COTP, either as a stand-alone utility or as a merged utility with SDG&E, DRA argued in each case that the net present value benefits are negative. In both the merged and stand-alone scenarios, DRA argued that the net benefits are in the range of -$137 to -$142 million. (Ex. 137, pp. 11,13; Ex. 138, pp. 11, 13; DRA's Concurrent Brief, pp. 34,76.) Incorporating expert witness testimony from IEP on the ER-90 assumptions further increases the negative benefits of Edison's participation in COTP. In the proposed decision, the ALJ found that the net present value benefits were negative with respect to Edison's involvement in COTP. However, in contrast to the proposed decision where the ALJ found that -$19 million in net present value benefits were insignificant, we find here that significant negative net present value benefits do exist, and that Edison's participation in COTP is not cost-effective. (Proposed Decision, p. 62.)

B. PG&E

DRA argued that PG&E's participation in COTP, compared to a muni-only COTP, resulted in net present value benefits of approximately $84 million. (Ex. 135, pp. 5,7; DRA's Concurrent Brief, p. 33.) At the same time, DRA's analysis of the cost-effectiveness of PG&E's participation incorporated a number of inconsistencies with ER-90 assumptions raised by IEP's expert witness. As such, we will make the necessary adjustments to DRA's analysis. These are summarized in Table 2 below. First, IEP noted that both DRA and PG&E used gas price forecasts that are 15% higher than those used in ER-90. IEP recommends a 15% reduction in production cost benefits to reflect the 15% lower gas price. IEP argued in its brief that even with this adjustment COTP production cost benefits for PG&E are overstated. (IEP's Concurrent Brief, p. 13.) We will adopt IEP's recommendation of a $29 million decrease in production costs and QF energy benefits relative to DRA's analysis.

Table 2

Adjustments to DRA's Estimated Cost/Benefit Analysis for PG&E Full Participation vs Muni Only
NPV - Millions of 1993 Dollars

DRA's Estimated Net Benefit	83.9
Adjustments:	
ER-90 Capacity Need Date	-15.5
ER-90 Gas Price Forecast	-29.0
ER-90 QF Capacity Benefit	- 3.8
Cut PG&E Combined Cycle O&M by 25% per CEC/SCE and SDG&E	-12.0
No Wholesale Profit after 1995	-36.0
Net Benefits After All Adjustments	-12.4

Second, IEP argued, based on consistency with ER-90 assumptions, that the capacity need date for PG&E should be later than DRA assumed. IEP, using ER-90 assumptions, presented evidence that the need for capacity for PG&E will not occur until 2007, compared to DRA's assumption of 2003.[19] DRA stated in its brief that because it assumed IOU recovery of 500 MW of capacity on the existing Intertie in 2005 in the muni-only case, the net capacity benefits between the muni-only and the full participation COTP

19 The deferral of need for capacity is the result of ER-90's higher forecasts for demand-side management programs, ER-90's lower reserve requirements and PG&E's proposed repowering of units in San Francisco which would add 188 MW of generation in 1999.

cases in DRA's analysis are much smaller than in the IOU's analysis. Therefore, the effect of IEP's adjustment for capacity benefits would also be much smaller. (DRA's Concurrent Brief, pp. 36,37.) IEP's estimate of the reduction in PG&E's forecasted capacity benefits is $10 million. Unfortunately, neither IEP nor DRA have attempted to quantify the magnitude of the adjustments to DRA's estimate of PG&E's capacity benefits associated with IEP's adjustment. Given the small capacity benefits shown in DRA's analysis,[20] the adjustment to DRA's estimate will certainly be quite small. However, with respect to the $15.5 million in reduced benefits for combined-cycle fixed O&M associated with the later capacity need date, we will adopt IEP's recommended adjustment to DRA's estimated production cost benefits for PG&E.

In addition to IEP's adjustments based on ER-90 assumptions, we will make a number of other adjustments to DRA's analysis based on other of IEP's concerns. (Ex. 159 and 160; IEP's Concurrent Brief, pp. 16-19.) First, based on IEP's testimony and subsequent cross-examination, the additional capacity on COTP will not reduce QF capacity payments. As such, we will reduce to zero the $3.8 million in QF capacity benefits shown by DRA. Second, we will adopt IEP's recommendation that we use CEC's data developed in ER-90 to evaluate PG&E's combined cycle O&M costs. This reduces DRA's estimate of PG&E's production cost benefits by an additional $12 million. Finally, we agree with IEP that DRA has overstated the wholesale sales margin for PG&E. In its own analysis, PG&E did not claim any additional profit from increased wholesale sales in a full participation case relative to a muni-only COTP. However, DRA included $90.4 million in additional profit margin on sales to TANC. We are especially concerned with the wisdom of including

20 Based on DRA's estimated capacity benefits of $1 million from Ex. 135 at 5,7.

profit margin differences after 1995 when TANC members will have the same level of purchases from PG&E with and without COTP. (Ex. 5, p. 63; DRA, Weatherwax, Tr. 1117.) We will accept IEP's recommendation to decrease wholesale sales margin benefits by $36 million for post-1995 sales.

Given the above adjustments to DRA's cost/benefit analysis, the $84 million in net present value benefits for PG&E is reduced by $96.4 million. This results in a negative $12.4 million net present value benefits for PG&E's participation in COTP, compared to a muni-only COTP scenario. Based on our adopted adjustments, we find that PG&E's participation in COTP, compared to a muni-only COTP scenario, provides a negative net present value benefit to ratepayers. Therefore, we conclude that PG&E's participation in COTP is not cost-effective.

C. SDG&E

Finally, with respect to SDG&E's participation in COTP, DRA argued that there is a $22 million net present value benefit from SDG&E's participation in COTP versus a muni-only COTP. (Ex. 134, pp. 11, 13; DRA's Concurrent Brief, p. 35.) DRA's analysis is consistent with most ER-90 assumptions, leading us to conclude that SDG&E's participation in COTP, based on the cost/benefit analysis performed in this proceeding, is cost-effective for its ratepayers. However, we remain troubled by the fact that SDG&E has not demonstrated to the Commission the feasibility of negotiating long-term contracts for Northwest capacity at reasonable rates. Public Utilities Code Section 1102 explicitly requires the Commission to consider the feasibility of Applicants negotiating long-term contracts at reasonable rates as part of its CPC&N review process:

> (a) . . . [I]n addition to the requirements of [P.U. Code §§ 10001-10] . . .an electrical corporation proposing to construct an electrical transmission line to the northwestern United States shall provide the commission with sufficient reliable information to enable the

> commission to determine that the proposed line, at the electric rates expected to prevail over the useful life of the line, will be cost effective. The commission, in its analysis of the forecast cost of electricity, shall take into consideration the recent increases in the charges for purchasing surplus electricity from the northwestern United States, the possibility of future increases in those charges, the feasibility of negotiating long-term contracts under reasonable charges, and the feasibility of purchasing electricity directly from Canada rather than through the Bonneville Power Administration.
>
> (b) The commission shall not issue a certificate of public convenience and necessity unless it is satisfied that the electrical corporation has provided the information described in subdivision (a).

In conjunction with our concerns about the availability of Northwest capacity, SDG&E's undemonstrated feasibility of negotiating long-term capacity contracts makes it doubtful that these net present value benefits will accrue to ratepayers. We conclude that SDG&E has not met its burden under P.U. Code § 1102 that it persuade the Commission of its feasibility to negotiate long-term contracts under reasonable charges. As such, we cannot approve SDG&E's application for participation in COTP at this time.

Environmental Considerations

Under CEQA, findings for any significant environmental effects of a project are only required when a public agency approves or carries out a project. (CEQA Guidelines § 15091.) Since we are denying a CPC&N for the COT project, it is not necessary to make any findings regarding the significant effects identified in the final EIS/EIR prepared by TANC and WAPA.

Requests for Findings of Eligibility

Pursuant to Rule 76.54 of our Rules of Practice and Procedure, TURN and Gregory H. Bowers request a finding of eligibility for compensation in this proceeding. TURN has been found eligible for compensation for calendar year 1990 in A.89-08-024 and, therefore, pursuant to Rule 76.54(a), is found eligible in this proceeding.

Bowers' request states that he is a resident of the State of Washington, a former FERC employee, and now an engineering consultant in the field of power system planning. He says that all his expenses in regard to his participation in this proceeding have been paid out of his own pocket. He does not receive any grants or other financial support. Virtually all of his efforts in the last quarter of 1990 were dedicated to this proceeding. He asserts that he is not independently wealthy and that the time and expense of his participation represent a financial hardship. His estimate of his expenses is $38,500. The issues he raised included adjustments to Applicants' energy benefits and a new capacity analysis, both of which address the issue of cost effectiveness of COTP for each of the Applicants and were not raised by other parties. We find that Bowers is eligible for compensation.

The Petition to Set Aside Submission

On January 8, 1991, DRA petitioned to set aside submission for the acceptance into evidence without hearing of three additional exhibits to impeach Edison's showing. The additional exhibits are (1) a portion of Edison's prepared testimony submitted in A.90-12-018 regarding SONGS I post cycle II, capital additions, (2) a portion of Exhibit 25 in A.88-12-012 (Edison's application for a CPC&N for Devers-Palo Verde II Transmission Line), and (3) a portion of Exhibit 26 in A.88-12-012.

DRA asserts that the proposed exhibits are relevant to the issue of the correctness of the ruling striking DRA's and IEP's prepared testimony concerning the measurement and valuation of residual air quality effects of IOU participation in COTP. The portion of Edison's 1992 general rate case application (A.90-12-018) demonstrates (1) that Edison is simultaneously arguing this issue in opposite and contradictory ways in different proceedings, and (2) the great importance of the Commission's being consistent across proceedings on this issue. The exhibits associated with the Devers-Palo Verde II proceeding are relevant and material (1) to explain more clearly what the Commission did in D.88-12-030, and (2) to demonstrate that Edison's current position is inconsistent with both its prior position on another interstate transmission line and the Commission's policy.

Edison and PG&E filed in opposition, arguing that the issues sought to be raised by DRA are environmental issues which were considered in the final EIS/EIR for COTP, which has been certified without challenge, and should not be subject to this late, collateral attack; and that treatment of environmental issues in this proceeding is justifiably different from the way environmental issues have been treated in other proceedings because of the difference in timing of the EIR process in those proceedings as compared to the COTP applications. Therefore, according to Edison and PG&E, the proposed exhibits are irrelevant.

The ALJ denied DRA's motion. (Proposed Decision at p. 81.) Since we are denying the applications, and because we have determined that the ALJ erred in excluding evidence relating to residual environmental costs and benefits, we do not find it necessary to reverse the ALJ's ruling on DRA's petition to set aside submission. However, we note that if the Applicants reapply for a CPC&N, any inconsistent position taken by Edison in other proceedings on these issues would be relevant.

Applications Are Denied

On the record in this case, the applications are denied since the Applicants failed to meet the burden of proof with respect to Section 701.1 of the Public Utilities Code as discussed above. Given the record developed in the case, we find the participation in COTP not cost effective for PG&E and Edison. While we find SDG&E's participation cost effective, we have concerns with respect to the availability of PNW capacity and energy. We are not convinced of the feasibility of negotiating long-term contracts at reasonable rates as required by Section 1102 of the Public Utilities Code.

Findings of Fact

1. Consideration of the costs and benefits of residual environmental effects is consistent with this Commission's current policies.

2. It is expected COTP will be built regardless of the participation of Applicants.

3. Applicants overstated PNW capacity benefits.

4. We find PNW capacity available, but we do not find enough available to support IOU participation in the project.

5. We are not persuaded by the CEC's unquantified strategic benefits arguments.

6. We are not persuaded that equity participation in COTP is necessary to obtain for ratepayers the unquantified benefits the IOUs claim.

7. PG&E stated that SOTR costs are linked to the construction of COTP.

8. The Applicants' estimate that SOTR costs will be zero is not credible.

9. The inclusion of the Los Banos-Gates line in 2008 at a cost of $118 million in 1993$ is a reasonable proxy for additional reinforcement actions PG&E would undertake because of COTP's construction.

10. We adopt DRA's allocation of $40.9 million in SOTR costs to PG&E and $33.1 million to Edison.

11. We believe that the CDWR and SMUD contracts will expire in 2005 in a muni-only COTP scenario.

12. We adopt the following assumptions with respect to our cost effectiveness analysis: (1) transmission-loss protocols used by the IOUs for the existing Pacific Intertie system, (2) DRA's Northwest capacity and energy availability estimates, (3) DRA's

estimate of SOTR costs, (4) that Intertie layoffs by SMUD and CDWR will occur in 2005, and (5) that it is appropriate to include capacity benefits resulting from QF bidding in the Update proceeding.

13. IEP raised a number of concerns regarding the inconsistency in both the Applicant's and DRA's analysis with respect to the ER-90 assumptions.

14. We adopt, with adjustments, DRA's cost/benefit analysis for each utility under the scenario of a muni-only versus full muni and IOU participation COTP.

15. Edison's participation in COTP would result in significant negative net present value benefits. Edison's participation in COTP is not cost effective.

16. We adopt IEP's recommended decrease of $29 million in production costs and QF energy benefits relative to DRA's cost/benefit analysis of PG&E's participation.

17. We adopt IEP's recommended decrease of $15.5 million in DRA-estimated production cost benefits for PG&E for its combined-cycle fixed O&M associated with the later capacity need date.

18. We adopt IEP's recommendation to reduce to zero the $3.8 million in QF capacity benefits shown by DRA in its cost/benefit analysis of PG&E's participation.

19. We adopt IEP's recommendation of reduced combined cycle O&M costs for PG&E. This reduces DRA's estimate of PG&E's production cost benefits by an additional $12 million.

20. We adopt IEP's recommendation to decrease DRA's estimate of wholesale sales margin benefits for PG&E by $36 million for post-1995 sales.

21. PG&E's participation in COTP, compared to a muni-only COTP scenario, results in a negative net present value benefit to ratepayers. PG&E's participation in COTP is not cost-effective.

22. Based on the cost/benefit analysis performed in this proceeding, SDG&E's participation in COTP is cost-effective.

23. SDG&E has not demonstrated the feasibility of negotiating long-term contracts for Northwest capacity at reasonable rates.

24. TURN and Bowers have requested a finding of eligibility for compensation under Rule 76.54(a).

Conclusions of Law

1. There are fundamental differences between the analysis of environmental impacts under CEQA (Public Resources Code Section 21000 et seq.) and the cost-benefit analysis required by Public Utilities Code Section 701.1.

2. Public Utilities Code Section 701.1 does apply to this proceeding and such application does not constitute retroactive operation of the statute.

3. The ALJ erred in excluding consideration of testimony on residual environmental costs and benefits presented by DRA and IEP. However, because of the Permit Streamlining Act deadline, we cannot now reopen the hearings in order to provide an opportunity for cross-examination on this testimony. Therefore, we will not reverse the ALJ's ruling and admit the evidence.

4. The Applicants have not carried their burden of proving cost effectiveness under Public Utilities Code Sections 701.1.

5. Southern California Edison Company and Pacific Gas and Electric Company have not met their burden of proving cost effectiveness under Public Utilities Code Section 1102.

6. San Diego Gas & Electric Company has not met its burden of proving the feasibility of negotiating long-term contracts under reasonable charges under Public Utilities Code Section 1102.

7. CEQA requires no findings on significant environmental effects when a project is not approved.

8. Both TURN and Gregory H. Bowers are eligible for compensation in this proceeding pursuant to Rule 76.54 of the Commission's Rules of Practice and Procedure.

9. Edison, PG&E and SDG&E should not be granted a CPC&N for participation in the construction of the COT project.

O R D E R

IT IS ORDERED that the applications for a certificate of public convenience and necessity filed by Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company for participation in the California-Oregon Transmission Project are denied.

This order is effective today.

Dated April 24, 1991, at San Francisco, California.

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

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

NEAL J. SHULMAN, Executive Director

APPENDIX A
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List of Appearances

Applicants: Roger J. Peters and J. Peter Baumgartner, Attorneys at Law, for Pacific Gas and Electric Company; Jerry Brody, Richard K. Durant, and Ann Cohn, Attorneys at Law, for Southern California Edison Company; and James F. Walsh, III, Attorney at Law, for San Diego Gas & Electric Company.

Protestant: Gregory H. Bowers, for self.

Interested Parties: Mark N. Aaronson, Thomas R. Adams, and Marc D. Joseph, Attorneys at Law, for International Brotherhood of Electrical Workers; Lori Adams, for U.S. Windpower, Inc.; C. Hayden Ames, Attorney at Law, for Chickering & Gregory; Richard Owen Baish, Phillip D. Endom, and Randolph L. Wu, Attorneys at Law, for El Paso Natural Gas Company; Patrick J. Bittner and William M. Chamberlain, Attorneys at Law, for California Energy Commission; Messrs. Jackson, Tufts, Cole & Black, by William H. Booth, Joseph S. Faber, and Evelyn K. Elsesser, Attorneys at Law, for California Large Energy Producers Association; David Branchcomb, for Henwood Energy Service, Inc.; Thomas Corr, Attorney at Law, for Independent Power Corporation; Messrs. Brobeck, Phleger & Harrison, by Gordon E. Davis, Attorney at Law, for Brobeck, Phleger & Harrison; Messrs. Grueneich, Ellison & Schneider, by Barry H. Epstein, Attorney at Law, for Positive Resolution of Powerline Problems; Norman J. Furuta, Attorney at Law, for the Department of Navy; Adrian Hudson, for California Gas Producers Association; William B. Marcus, for JBS Energy, Inc.; Melissa Metzler, for Barakat & Chamberlin; Mark A. Minich and E. R. Island, Attorneys at Law, for Southern California Gas Company; Sara Steck Myers, Attorney at Law, for California Energy Company; Patrick J. Power, Attorney at Law, for City of Long Beach; John D. Quinley, for Cogeneration Service Bureau; Michel Peter Florio and Joel R. Singer, Attorneys at Law, for Toward Utility Rate Normalization; Jan Smutny-Jones, for Independent Energy Producers; Messrs. Downey, Brand, Seymour & Rohwer, by Philip A. Stohr and Ronald Liebert, Attorneys at Law, for Industrial Users; Robert B. Weisenmiller, for MRW and Associates; Henry M. Ramirez, for Department of Water Resources; Robert Weatherwax, for Sierra Energy & Risk Assessment; Rob Lamkin, for Northern California Power Agency; Margaret Manes, Attorney at Law, for Sierra Pacific Power; Messrs. Thelen, Marrin, Johnson & Bridges, by Michael Hindus and Beth Anne Yeager, Attorneys at Law, for several interested parties; and Barkovich & Yap, by Barbara Barkovich, for self.

APPENDIX A
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List of Appearances

Division of Ratepayer Advocates: James E. Scarff, Attorney at Law, and Denise S. Mann.

Commission Advisory and Compliance Division: Jennifer Ruffolo.

Public Advisor: Alannah Kinser.

(END OF APPENDIX A)

APPENDIX B

COT PROJECT PARTICIPANTS

	Project Percent	Entitlement MW *	Financing Ownership Interest
PUBLICLY OWNED			
Transmission Agency of Northern California	42.2916	677	45.1110
Alameda, Lodi, Roseville, Biggs, Lompoc, Santa Clara, Gridley, Palo Alto, Ukiah, Healdsburg, Redding			
Plumas-Sierra Rural Electric Cooperative			
Sacramento Municipal Utility District			
Modesto Irrigation District			
Turlock Irrigation District			
Southern Cities			
Anaheim	3.0198	48	3.2212
Azusa	.3020	5	.3221
Banning	.1510	2	.1611
Colton	.3020	5	.3221
Riverside	2.0762	33	2.2146
Vernon	1.6987	27	1.8119
50 MW Allottees			
Carmichael Water District	.0625	1	.0667
El Dorado Hills Community Services District	.1875	3	.2000
San Juan Suburban Water District*****	.0625	1	.0667
Shasta Dam Area Public Utility District	.4375	7	.4667
Southern San Joaquin Valley Power Authority****	2.0625	33	2.2000
Trinity County Public Utility District	.3125	5	.3333
INVESTOR-OWNED			
Pacific Gas and Electric Company	20.3918	326	21.7513
San Diego Gas and Electric Company	2.8549	46	3.0452
Southern California Edison Company	17.5375	281	18.7061
STATE			
California Department of Water Resources		0**	
FEDERAL			
Western Area Power Administration***	6.25	100	0.0000

* Based on COTP capacity of 1,600 MW.

** CDWR has the right to buy a 6.04 percent share in the year 2005; if this option is exercised all participants other than Western and the 50 MW Allottees will reduce their shares proportionately.

*** Western will retain a 300 to 600 MW share of transfer capability (depending on final rating of the line) between Redding and Tracy.

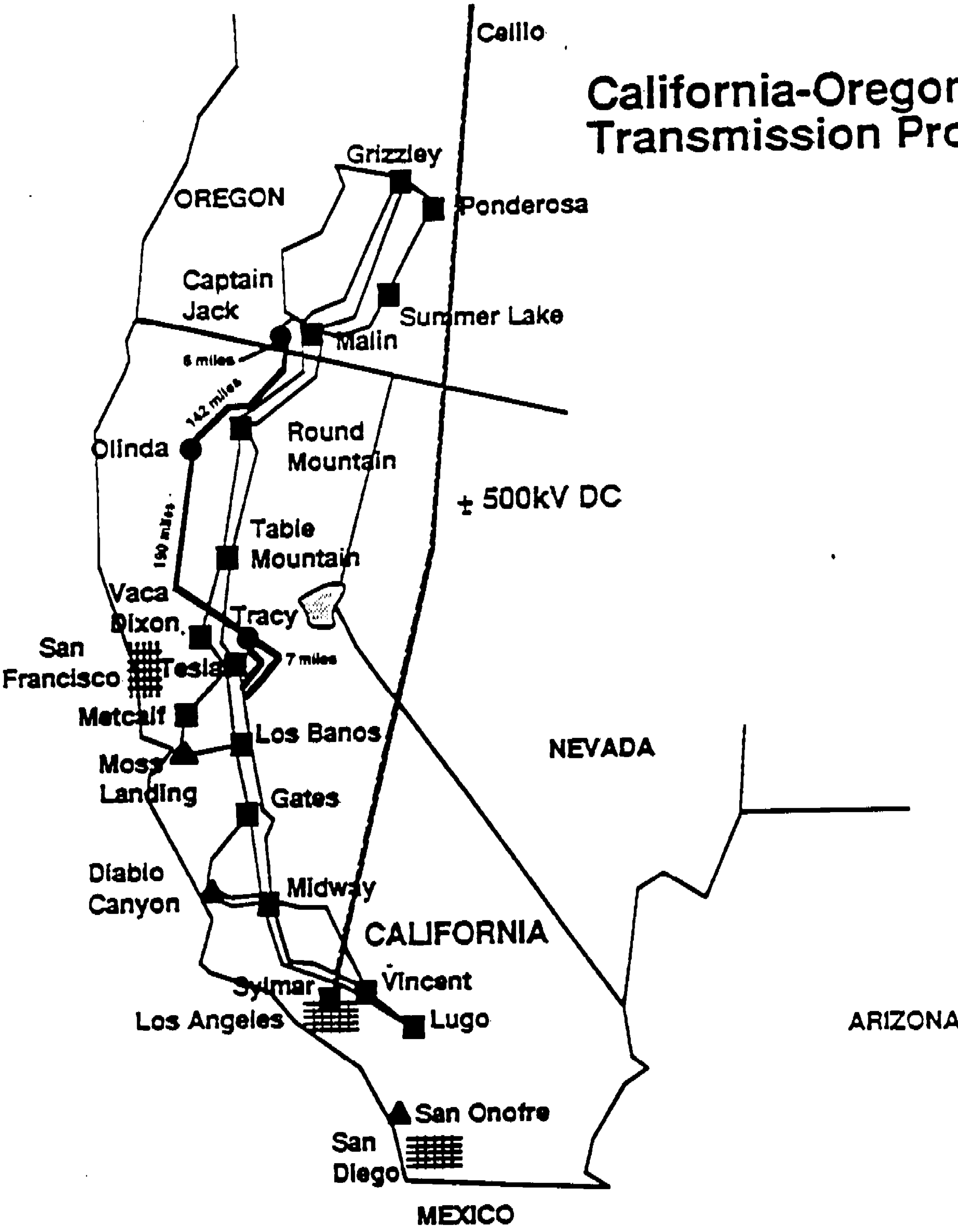
**** Assigned to PG&E, to become effective upon execution of the PPA

***** Assigned to Western to become effective upon execution of the PPA

Source: Excluding facilities owned by Western COTP MOU, COTP/LBGTP DRAFT EIS/EIR, Volume 1, page 1.0-3, November 1986.

(END OF APPENDIX B)

California-Oregon Transmission Project



▲ Existing Generating Plants

■ Existing Substations, Switching StationS

● New 500kV Substation

COTP

Existing 500kV AC

Existing ±500kV DC

Routes shown are schematic

(END OF APPENDIX C)

Why Availability of PNW Energy and the Price Savings Associated With It Have Decreased[1]

1. The closure of the 500 aMW Hanford Nuclear Generation Station.

2. The return to operation of about 750 aMW of shutdown aluminum plant lines pursuant to a new long-term rate design based upon the world price of aluminum.

3. The increased growth rate in PNW residential and commercial demand.

4. The plans of PNW interests to firm up "non-firm" capacity, thereby eliminating it from being offered to the non-firm market.

5. The increased spills of water from PNW dams on the Columbia and Snake rivers to facilitate anadromous fish reproduction.

6. The large number of sales of capacity and/or energy that have been made by BPA, PNW IOUs, and PNW generating public utilities to California interests over the existing, greatly enlarged Intertie.

Trend of Decreasing PNW Economy Energy Available for Export Likely to Continue[2]

1. To meet future resource needs, the PNW will probably permanently convert many of the power sales with California to exchanges.

2. BPA plans to "firm up" some of its non-firm hydro power through additional storage arrangements with British Columbia Hydro and additional gas fired resources to back up hydro production, resulting in lower average economy energy availability.

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1 Concurrent Brief of the Division of Ratepayer Advocates p. 23.

2 Id. p. 28.

Appendix D
Page 2

3. The new rate design under which PNW aluminum plants operate should ensure that their non-firm load of about 7000 GWh/yr will continue to siphon off substantial amounts of any non-firm generated which otherwise might be available for sale to California.

4. Environmental restrictions on coal burning and hydro generation may limit the energy available.

5. The CPUC recently granted a CPC&N to Edison (subject to various conditions) to build Devers-Palo Verde II which will further increase DSW power sellers ability to compete with PNW power.

(End of Appendix D)