ALJ/LTC/tcg

Decision 88 02 029 FEB 16 1988

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of PACIFIC GAS AND ELECTRIC COMPANY for a Certificate of Public Convenience and Necessity Authorizing Participation in the California-Oregon Transmission Project. (U39E)	Application 87-10-018 (Filed October 14, 1987)

ORIGINAL

OPINION DENYING APPEAL

I. Introduction

A.87-10-018 is PG&E's second COT Project application. On April 8, 1987 PG&E filed A.87-04-010, its first COT Project application. On May 8, 1987 the Commission's Executive Director informed PG&E by letter that A.87-04-010 was incomplete. In addition to listing certain deficiencies, the Executive Director's letter requested additional information from PG&E designed to cure the identified deficiencies. On May 28, 1987 the Commission issued D.87-05-067, an order administratively closing the A.87-04-010 docket; at the same time the Commission encouraged PG&E to file a new and complete COT Project application in timely fashion. PG&E did not appeal either the May 8th Executive Director letter or D.87-05-067. Instead, it submitted additional information to the Executive Director relative to A.87-04-010, and thereafter it submitted A.87-10-018, its second COT Project application.

By letter dated November 13, 1987, the Commission's Executive Director informed Pacific Gas and Electric Company (PG&E) that its October 14, 1987 Application for a Certificate of Public Convenience and Necessity (CPC&N) (A.87-10-018) authorizing participation in the California-Oregon Transmission (COT) Project was incomplete as submitted, and therefore rejected. (A copy of the November 13th letter to PG&E's counsel is attached as Appendix A). On December 14, 1987 PG&E filed a formal appeal challenging the Executive Director's determination. This decision resolves the issues raised by PG&E's appeal, as required by Government Code Section 65943.

II. Standard of Review

The instant appeal was made by applicants in reliance on Government Code §65943 of the Permit Streamlining Act (PSA) and Rule 85 of the Commission's Rules of Practice and Procedure. Government Code §65943(c) provides as follows, in relevant part:

> "(c) If the application together with the submitted materials are determined not to be complete pursuant to subdivision (b), the public agency shall provide a process for the applicant to appeal that decision in writing to the governing body of the agency..."

The Commission has not initiated a separate appellate process to handle challenges to the determination of incompleteness by the Executive Director. However, we do have appellate rules that generally govern our proceedings. Until such time as we may elect to create a distinct appellate process with regard to the PSA, Rule 85 of the Commission's Rules of Practice and Procedure is the appropriate procedure for such challenges. That rule specifies that an application for rehearing of a Commission order or decision shall be filed within 30 days after the date of issuance. The appeal herein was filed in compliance with Rule 85.[1]

1 Government Code § 65943 also provides that if the final written determination of the appeal is not made within 60 calendar days after receipt of applicant's written appeal, the application with the submitted materials shall be deemed complete for the purposes

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In reviewing the Executive Director determination that the application is incomplete, we must consider both the requirements and fundamental goals of the PSA (Govt. Code §§ 65920 et seq.) and the provisions and purposes of the Public Utilities Act. (Public Utilities Code §§ 201 et seq.) These statutes must be examined in conjunction with each other. It is an established rule of statutory construction that statutes should be interpreted with reference to the whole system of law, so that all may be harmonized, (58 Cal Jur. 3d §108). All acts relating to the same subject should be read together and harmonized if possible, Ebert v. State, (1949) 33 C.2d 502, Boyd v. Huntington, (1932) 215 C. 473. Accordingly, the responsibilities of the Commission in the PSA must be reconciled with the responsibilities of the Commission pursuant to the Public Utilities Act. Any standard of review we adopt must comport with these principles.

Of paramount importance in formulation of this standard is consideration of the consequences of an agency's determination of completeness. Under the PSA the Commission has only 180 days to reach a final decision from the date the applications are determined to be complete or the project is "deemed approved". (Govt. Code §§65952, 65956(b)). Thus, once the Commission accepts an application for filing under the PSA, the opportunity for additional discovery prior to hearings is minimal. For example, if the instant application had been determined to be complete, the tentative schedule issued by ALJ Ruling on September 22, 1987 would

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(Footnote continued from previous page)

of this chapter. Since this decision is issued within the time limits mandated by the statutory scheme, the provision for deemed completeness is not applicable.

have allowed for only six weeks between acceptance of the applications and the completion of the draft DRA testimony.

These consequences must be viewed in conjunction with the obligations of the Commission under the Public Utilities Act. The Commission's basic responsibility is to evaluate whether a proposed project is, or will be required for the public convenience and necessity. (PU Code §1001). In reaching this determination, the Commission is required to make separate findings of fact and conclusions of law on all material issues. Failure of the Commission to make such findings and conclusions will result in annulment of the Commission's order (Greyhound Lines, Inc. v. PUC, 65 C.2d 811 (1967)). In a project of this scope such findings and conclusions necessarily will be extensive. All such findings must be based on substantial evidence in the record. (Yucaipa Water Co. No. 1 v. PUC (1960) 54 C.2d 823.) PU Code § 1102 specifies that the Commission shall not issue a certificate of public convenience and necessity unless it is satisfied that the electrical corporation has provided all information described in the statute. In order to fulfill this obligation, the Commission must have before it a complete record on which to base its decision. In a case of this complexity, there is no doubt that the necessary record to make a reasoned decision must be very comprehensive.

The Commission has an exceedingly tight time frame in which to discharge these responsibilities, once the application is accepted as complete and the time limits begin to run under the PSA. It must obtain and analyze all evidence, hold hearings, review briefs and issue its decision within 180 days. Since any possible extension of this time frame is within the sole discretion of the applicants, the Commission has no assurance of any extension of time. Govt. Code §§ 65950, 65957. Completeness of an application at the beginning of the proceeding is therefore, critical.

It follows from the time constraints of the PSA and the substantial responsibility of the Commission under the Public Utilities Act, that the critical determination of completeness must lie within the reasonable discretion of the Commission. The Legislature has apparently recognized this logic in electing to leave the determination of completeness to the agency's discretion. The only pertinent requirement of the Act is that each agency prepare an "Information and Criteria List" to help inform applicants of information that will be necessary (Gov't. Codes §§ 65940-41). The Commission adopted such a list in 1979 (1 CPUC 2d 166 (1979)). The Legislature did not elect to prescribe to agencies what information they must obtain, but was silent on the substantive contents of such lists. The Legislature further did not elect to dictate to the Commission that the Information and Criteria List is the exclusive standard to be applied in determining completeness. We therefore conclude that the Commission has been left to exercise its discretion in these matters, so long as it is exercised reasonably. Our standard of review must recognize the realities imposed by the Public Utilities Act and the PSA and must also reflect the fact that the burden of proof justifying the issuance of the certificate is clearly on the applicant.

It should be understood that the foregoing discussion concerns our good-faith compliance with the PSA--which we support fully--and in no way marks an attempt to circumvent the statute.

We turn now to the specific arguments raised by PG&E in contesting the Executive Director's determination.

III. <u>PG&E's Grounds for Appeal</u>

A. <u>Introduction</u>

PG&E makes three arguments in support of its appeal. First, it asserts that it has met all applicable legal requirements. Second, it maintains that the Executive Director's actions effectively hold PG&E "hostage" to events beyond its control. Finally, PG&E maintains that the review process used in this instance constitutes a regulatory "moving target," which subverts the PSA.

B. The Application Satisfies all Applicable Legal Requirements.

PG&E maintains that Public Utilities Code Sections 1001, 1003, 1004, and 1102 specify the totality of information to be reviewed by the Commission in a CPC&N proceeding, and that the Commission's implementing General Order (GO) 131-C is the standard for gauging completeness of a particular CPC&N application. PG&E believes that its application meets or exceeds all GO 131-C filing requirements (A.87-10-018, pp. 3-5), and provides a sufficient basis for the Commission to initiate formal review proceedings.

Within this context, PG&E challenges the validity of the various deficiencies noted in the Executive Director's letter. For example, it asserts that rejection based on inadequate Section 1102 analysis[2] is misplaced, because Section 1102 is not a threshold standard for measuring the completeness of A.87-10-018. According to PG&E:

> ". . . If the Commission wishes to include Section 1102 information as a specific filing requirement, it should do so by amending General Order 131-C. Otherwise, the information required by Section 1102 should be adduced during the hearing process." (PG&E Appeal, p. 11.)

2 Section 1102 requires PG&E in this instance to supply the Commission with "sufficient 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." (Public Utilities Code § 1102(a).)

PG&E asserts that § 1102(a) also requires the Commission to perform its own analysis of the forecast cost of electricity, as well as other factors bearing on Northwest power purchases, prior to issuing the COT Project CPC&Ns. Thus, assuming PG&E's application contains "sufficient reliable information" to enable the Commission to discharge its § 1102 obligations, in PG&E's view the statutory language cannot be used as a threshold bar to entertaining the application.

Another noted deficiency was Edison's failure to translate its Pacific Northwest (PNW) computer models into FORTRAN 77. PG&E argues it has no control over this situation, and furthermore, that any failure to provide access to computer models prior to acceptance of an application does not constitute a valid deficiency under GO 131-C.

PG&E also challenges the Executive Director's determination that A.87-10-018 is deficient in providing no support for its assumption that non investor owned utility (IOU) project participants will agree that the South of Tesla Transmission Principles satisfy the COT Project Memorandum of Understanding (MOU).

The MOU requires PG&E to provide up to 1,000 MW of firm-bi-directional transmission service between its Tesla and Midway substations for certain project participants. PG&E's initial application included provision for a new transmission line (the Los Banos-Gates Project) to meet this requirement. The initial application was found deficient, partly because this provision was inconsistent with the initial COT Project applications of Edison and SDG&E. In response, PG&E included in its second application a set of transmission "principles" which require it to install certain noncertifiable transmission system reinforcements between Tesla and Midway by 1991. PG&E, Edison, and SDG&E agreed to these principles in October 1987, but the Transmission Agency of Northern

California (TANC) and the Southern California public agency participants have not agreed to them.

PG&E believes the facilities and service to be provided under the principles fully satisfy its obligations under the MOU. Further, it asserts that the lack of formal agreement by TANC and the Southern California public agency participants should not prevent the Commission from initiating the review process or accepting A.87-10-018.

PG&E also regards as unmerited the rejection of A.87-10-018 based on Edison's failure to provide adequate information concerning an exchange agreement between Edison and the Los Angeles Department of Water and Power (LADWP). It believes that questions about its own lack of participation in this exchange agreement are irrelevant to its participation in the COT Project. It also contends that the Public Utilities Code and GO 131-C do not allow for rejection of A.87-10-018 simply because an applicant fails to explain its reasons for not entering into an exchange agreement which does not impact its system or its ratepayers.

PG&E also believes that other alleged deficiencies are legally invalid, inappropriate challenges to assumptions or methodologies (more appropriately considered in hearings), requests for information already provided, misundertandings, or "additional prediscovery data requests." (PG&E Appeal, pp. 16-17.)

C. PG&E Asserts its Application is Being Held Hostage to Events Beyond its Control.

First, PG&E challenges the Executive Director's determination that its application is incomplete because TANC and the public agency participants have not formally agreed to the Tesla to Midway Transmission Principles; PG&E believes such an outcome effectively places those non IOU participants in a position of power to forestall acceptance of A.87-10-018 indefinitely. Moreover, it believes that the Executive Director's requirement for a formal agreement among these parties will place PG&E at a disadvantage at the bargaining table.

Second, PG&E opposes the requirement that BPA issue its final Long-Term Intertie Access Policy (LTIAP) prior to acceptance of A.87-10-018, consistent with its view that California utilities should not wait to pursue access to Northwest power for further refinements to the LTIAP. PG&E also notes that nothing in Section 1102 or GO 131-C requires publication of the LTIAP as a condition to acceptance of A.87-10-018.

Third, PG&E reiterates that it has no control over either the format of Edison's PNW computer model or the exchange agreement between Edison and LADWP.

D. Subversion of the Permit Streamlining Act

PG&E believes that review of its second application should be limited to determining whether deficiencies in the first rejection letter have been remedied. It challenges the review process which preceded rejection of A.87-10-018, because it believes issues such as (1) signed agreements for South of Tesla service and (2) analysis of BPA's final LTIAP, should have been raised during the first review (PG&E Appeal, pp. 21-22). It believes the review process employed in this instance constitutes a "regulatory moving target," in violation of the Commission's specific obligations under the PSA (Govt. Code § 65943(a)).

PG&E also questions the role of the Division of Ratepayer Advocates (DRA) in the review process, because it perceives DRA lacks objectivity in carrying out this task.

IV. DRA's Response to PG&E's Appeal

A. Introduction and Preliminary Matters

On January 25, 1987, DRA filed lengthy formal comments responding to the appeals of PG&E, Edison, and SDG&E. As a preliminary matter, DRA objects to the notion that PG&E's

application has been "rejected," since the Commission has kept the A.87-10-018 docket open in order to allow the parties the opportunity to proceed on all issues of the case which are not dependent on the missing information. DRA submits the only effect of the Executive Director's letter is to delay the start of the clock running under the PSA.

DRA also reports that PG&E has stopped responding to DRA data requests, pending the outcome of this appeal.

Furthermore, DRA notes that if the Commission grants PG&E's appeal, effectively finding its application to be complete, the clock will start to run under PSA and the Commission will have only 180 days to reach a decision on the merits.

Finally, DRA argues that the COT Project requires close scrutiny in view of the sensitivity of applicants' cost effectiveness assumptions. It notes that the applicants have relied on nontraditional benefits (i.e., increased system stability and reliability) in order to bolster their cost-effectiveness analysis. Thus, the missing information can be of critical importance, as it relates to the analysis of a single benefit which could tip the scales against cost-effectiveness.

B. The Missing Information

1. In General

DRA asserts that PG&E's application suffers from multiple deficiencies, over and above the major items discussed in the appeal. It calculates 40 common uncorrected deficiencies from the initial applications, 20 common deficiencies arising from the second applications, and 17 deficiencies specific to PG&E's application.

2. PU Code Section 1102

A primary concern is the failure of PG&E to provide "sufficient reliable information" of PNW power prices, as required by Public Utilities Code § 1102. DRA notes a substantial conflict between applicants' current estimates of PNW capacity and energy availability and BPA's own most recent lower (by 1,500 Gwh) estimates of energy export sales. DRA also indicates that BPA is currently revising its estimates to mitigate certain fishery impacts. Applicants' current estimates are also much higher than available Energy Commission and QF industry forecasts.

DRA points to certain ongoing litigation which may require BPA to further mitigate fishery impacts associated with increased exports of hydroelectric power for COT and other projects, raising substantial questions that the COT Project is no longer cost effective (DRA Comments, p. 8). According to DRA:

> "BPA's revised final EIS which will contain its final mitigation proposals is scheduled for release in mid-March. Pending release of that document, the uncertainty surrounding fishery mitigation makes it impossible for the Commission to satisfy the mandate of PU Code § 1102." (DRA Comments, p. 8.)

DRA also maintains that the LTIAP, now scheduled for release in mid-April 1988, has a major bearing on the COT Project economic analysis. The magnitude of the potential BPA actions is so great, in DRA's view, that they could eliminate nearly all energy and capacity benefits from the project. DRA states:

> "The utilities have argued that they should not have to wait for BPA to issue its final LTIAP. But this is precisely the policy advocated by PU Code § 1102--that California utilities not commit themselves to expensive investments in transmission lines to the Northwest until BPA has made some commitment regarding price and availability of power." (DRA Comments, p. 9.)

Finally, DRA believes the Executive Director was correct to identify as a deficiency the fact that Edison's PNW computer model, used by all applicants, is not yet available to DRA in a readily known computer language. Edison's conversion of the model to FORTRAN will not be completed until mid-February, according to DRA. DRA cites the short lead time between acceptance of the applications and the due date for DRA testimony as further justification for refusing to allow the PSA clock to start.

3. <u>The Project South of Tesla</u>

As previously noted, PG&E's first COT Project application contained a request to build a new line south of the Tesla substation (Los Banos-Gates Project). The Los Banos-Gates Project is included in TANC's EIR at a cost of approximately $100 million. However, Edison and SDG&E did not include Los Banos-Gates in their initial applications, and the Executive Director noted this inconsistency as a deficiency in those applications.

In their second applications, all three IOUs sought consistency by agreeing to a set of principles regarding wheeling south of Tesla that would, according to DRA, provide a level of service somewhat less than "firm," albeit obviating the need for Los Banos-Gates.

DRA believes the Executive Director correctly refused to accept the applications in the absence of formal agreement by the non-IOU participants, and solely on the basis of the IOUs' representations that the non-IOU participants would ultimately agree to these principles. DRA points to PG&E's $100 million exposure in the event of litigation over the principles. DRA believes "this dispute between COTP participants as to what the COT Project is must be settled by all participants before the applications can be considered complete." (DRA Comments, p. 12.)

4. <u>Lack of Supporting Data</u>

DRA also believes the IOU applications are deficient for lack of any baseline studies of system reliability, given the claim that system reliability is a major project benefit.

5. <u>Failure to Disclose Relevant Information Re Edison-LADWP Transmission Capacity Exchange Agreement</u>

Edison and LADWP have agreed to exchange 820 MW of transmission capacity on lines to the PNW, partially conditioned on the construction of the DC upgrade. Edison would give LADWP 320 MW of Edison's capacity on the existing AC line and in exchange LADWP would give Edison 500 MW of capacity on the DC upgrade for a 35-year period. DRA asserts that Edison would thus gain an additional 400 MW of firm transmission capacity to the PNW even if the COT Project were not constructed. PG&E's application, like those of Edison and SDG&E, reflects Edison's participation in this exchange.

DRA believes the Commission needs to know about feasible alternatives and why they were rejected by the IOUs, in order to gauge project cost effectiveness. DRA believes that PG&E's deficiency, correctly noted by the Executive Director, is its failure to explain its own relationship to this exchange (as a party to the Pacific Intertie Agreement, PG&E needed at least to approve Edison's participation in the exchange agreement, according to DRA).

6. The Muni-Only Baseline

PG&E and Edison measure the benefits of the COT Project against a "muni-only baseline," which assumes that if these IOUs do not participate in the project, the munis will proceed to build the line by themselves.[3]

DRA believes PG&E and Edison's assumptions regarding the muni's construction costs are defective in that they have simply assumed that construction costs for the munis will be the same as for the IOU-muni combination. In DRA's view, this exaggerates the attractiveness of the muni-only option and consequently exaggerates the cost effectiveness of the COT Project. DRA believes the Executive Director correctly noted this as a deficiency.

3 DRA notes that under the conventional "no project" alternative baseline, PG&E's and Edison's costs of participation exceed benefits by over $200 million (DRA Comments, p. 18).

7. **Unrealistic Assumptions Re Current Operating Dispatch Procedures**

DRA believes that the IOUs' applications contained flawed assumptions that all generating plants are dispatched in optimum fashion. Such assumption, which does not jibe with actual practice in DRA's view, greatly exaggerates each IOU's ability to absorb PNW economy energy. According to DRA, the magnitude of this impact is $100+ million, in present value terms, over the life of the project (Affidavit of Robert Weatherwax; DRA Comments, p. 19). DRA believes the Executive Director acted properly in identifying this deficiency.

C. Information Needed for Evaluation Purposes

1. Generic Information

DRA believes that the Commission measures the issue of public convenience and necessity by resolving several issues:

- Do projected economic and strategic benefits outweigh the economic costs?
- Is the project more cost effective and/or less environmentally harmful than feasible alternatives?
- Are the risks to ratepayers acceptable that the benefits won't be achieved or the costs will be greater than forecast? (Section 1102).
- Is there an appropriate allocation of costs and benefits between populations of ratepayers over time?

In order to decide the issue of public convenience and necessity, DRA believes the Commission needs a detailed description of the proposed project, accepted by all participants, as well as a detailed description of all projected benefits, in verifiable form. Major benefits must always be described in detail, particularly where the proponent is relying on nontraditional benefits (e.g., increased system reliability, etc.) and nontraditional methods of benefits quantification.

2. The Statutory and Regulatory Framework

DRA's comments focus on four components of the framework to be used to review projects such as COT. These are: the Permit Streamlining Act, the CPUC Information and Criteria List, GO 131-C, and PU Code § 1102.

In terms of review under PSA, DRA believes that PG&E's position is overly legalistic. The real issue, in DRA's view, is whether the Commission and its staff have apprised the applicants of the required information in a timely and appropriate manner, prior to the filing of the applications. While the applicants object to the fact that the deficiency letters identified information requirements not specified in the Commission's formal regulations, DRA argues that the real issue is whether the utilities knew what sort of information the staff needed in order to review this significant project. DRA submits that the answer is "yes."

The Commission's Information and Criteria list, adopted pursuant to the PSA, requires certain definitive information from these applicants.[4] DRA submits that the applicants have failed to provide crucial information. For example, there is no agreement among project participants about the nature of the project south of Tesla, although D.89905 requires a full description of the proposed project, as well as details of its estimated cost.

The Information and Criteria List also requires a showing of public convenience and necessity, but in DRA's view the IOU applicants have failed to address this issue, instead justifying their participation on the notion that their failure to participate

4 See App. B to D.89905 (1979) 1 CPUC 2d 166.

will result in the construction of the line by the munis, ultimately at greater cost to ratepayers.

DRA also notes that the Information and Criteria List and PSA must not be interpreted in a manner that would frustrate CEQA, and the Commission's independent obligations as a responsible agency for the COT Project (the CEQA guidelines provide a responsible agency with 30 days to review an application for completeness). (Govt. Code § 65944(c).)

Finally, the Commission's Information and Criteria List requires submission by applicants of "Such additional information and data as may be necessary to a full understanding of the project." This provision mirrors the Commission's generic requirement for applications, Rule 15(c).

DRA disputes the applicants' arguments that compliance with GO 131-C largely satisfies their filing requirements for the COT Project. According to DRA, these filing obligations arise primarily from the Commission's Information and Criteria List and PU Code § 1102.

DRA submits that the applicants have interpreted their obligations under Section 1102 very narrowly and unpersuasively. According to DRA:

> "...The duty of the applicant is to have its application contain 'sufficient reliable information.' The only indication of what the Legislature meant by that phrase is contained in the second sentence. To conclude the Legislature meant nothing more than that an applicant must comply with the existing general filing requirements of GO 131-C is to conclude that the Legislature enacted meaningless legislation, a violation of common rules of interpreting statutes." (DRA Comments, p. 29.)

DRA also believes that applicants' narrow interpretation of their § 1102 obligations is inconsistent with the allocation of the burden of proof in this proceeding.

D. DRA's Response to Other Arguments Presented on Appeal

DRA denies the assertion that the Commission has created a regulatory moving target. DRA believes there is an affirmative obligation under PSA to critically evaluate the information submitted in response to the initial deficiency letters (Govt. Code §§ 65953(a)-(b)). Indeed PSA provides a 30-day review period for this purpose. Additionally, DRA maintains that the deficiencies noted in the second applications result from substantial changes made by applicants themselves. As examples, DRA cites deletion of the Los Banos Gates Project and substitution of the new South of Tesla transmission "principles"; the existence of the Edison/LADWP Exchange agreement, noted for the first time in the revised application of Edison, and first-time quantification of certain strategic benefits in the revised applications of Edison and SDG&E.

DRA also denies that it is using PSA to obtain information which should be obtained during normal discovery. It believes the applicants have failed to assert any legal authority for the proposition that the information requested is a discovery item, as opposed to required information for purposes of assessing the completeness of the applications.

Likewise DRA disputes PG&E's assertion that its application is being held hostage to outside events. For example, DRA contends that no entity other than PG&E is in a better position to resolve the south of Tesla issue. According to DRA:

> "Under either the proposed principles or PG&E's initial proposal--the Los Banos-Gates line--the transmission will occur largely over PG&E's lines. It is not the role of the Commission to resolve these disputes among the project proponents." (DRA's Comments, pp. 39-40.)

DRA makes a similar argument with regard to the Edison computer model, used in support of PG&E's application (DRA Comments, p. 40.)

Finally, DRA contends that there is nothing impermissible about DRA staff involvement in reviewing the applications for completeness. DRA points to the lack of any such prohibition in PSA, the Commission's Rules of Practice and Procedure, or general equitable principles. Furthermore, DRA believes that staffing constraints dictate DRA's involvement. Ultimately, however, DRA contends that its involvement has been fair, in that it has not taken a position on the COT Project, other than to state that it is impractical to evaluate the merits based on the information presented to date. DRA insists that it has no preconceptions that the project should be denied on its merits. Furthermore, DRA believes applicants are protected by this appellate process and that, in any event, they have failed to demonstrate any abuse of procedural rules or PSA.

E. Applicants' Replies to DRA's Comments

Pursuant to the ALJ's Ruling of January 26, 1988 PG&E and Edison filed timely replies to DRA's Comments. Most of the argument contained in these replies reiterates applicants' extensive prior argument; however, several points deserve further attention, and are discussed below and/or in Section IV.

Responding to DRA's concerns about fish kill impacts, Edison maintains that current available information is sufficient for the Commission's decisionmaking purposes. In support, Edison references a January 21, 1988 letter from BPA's counsel to the DRA COT Project Manager. Since this letter was unavailable to the Executive Director at the time the applications were rejected, its current availability does not resolve the question whether rejection of the second COT Project application constituted an abuse of discretion. Therefore, we do not find Edison's argument helpful in resolving the dispute before us.

Pointing to the problems posed by these appeals, Edison also argues that the Commission should develop a more refined published system of standards for CPC&N applications reflecting the anticipated diverse and nontraditional nature of resource proposals likely to come before it in the future. Edison cites Government Code § 65942 as requiring the Commission to revise its filing requirements "as needed so that they [are] current and accurate at all times." Edison suggests that the Commission develop, through its rulemaking process, such a refined published system (Edison Reply, p. 18).

It its Reply PG&E suggests that keeping these matters "on the docket" is inconsistent with rejection of its application. It believes the Commission's Rules of Practice and Procedure do not provide a mechanism whereby an application is not accepted but still in the docket (PG&E Reply, p. 7). PG&E contends that Rule 46 should not be interpreted as allowing the Commission to neither accept nor reject, "but instead hold an application in regulatory limbo"; it terms such a reading of the rule to be a "tortured interpretation" of the plain language.

V. Discussion

The preceding discussion of the deficiencies alleged by the Executive Director points up the level of controversy to be expected during the litigation phase of this application, and we serve notice that we expect the utilities to be forthcoming in their responses to these issues. We will not hesitate to refuse the granting of a CPC&N should the applicants not meet their burden under §§ 1001, et seq., and 1102 of the PU Code, and under our Rules.

Before us today, though, is the difficult problem of determining the adequacy of the utilities' applications to begin our formal consideration of the project. This Commission is fully aware of the scope of analysis that must be completed during the very brief time between our acceptance of the application and when we are required to act on the matter under the Permit Streamlining

Act. We do not believe, however, that we have the authority under the statutes to delay acceptance of an application in order to give ourselves and our staff greater time to consider the merits of a project. We believe instead that the applicants bear the burden of convincing us of the merits of their proposal during the 180 days allowed.

We do believe that we cannot reasonably accept an application for a project that is not yet well-defined, for to set a precedent of doing so would threaten to introduce chaos into our already strained review process. The 180-day limit imposed by the PSA on our deliberations must reasonably assume that we have a project to deliberate. Otherwise, neither our staff nor interested parties would have a fair chance to consider the merits of a proposal that is open to significant revision <u>after</u> the review process has begun. This inability of parties to examine fully a revised proposed project might well lead us to refuse the granting of a CPC&N, but only after a great deal of time and effort has been wasted by our staff and interested parties. The wasting of time was clearly not the intent of the PSA, nor is it to the benefit of California ratepayers.

We come then to the project definition issue that speaks directly to whether we can reasonably accept this application and set the 180-day clock ticking--the South-of-Tesla extension. The memorandum of understanding (MOU) requires PGandE to provide 1000 MW of firm bi-directional power between Tesla and Midway. In its initial application PG&E proposed to meet this obligation by constructing a new transmission line known as the Los Banos-Gates project. Neither SDG&E nor Edison proposed in its application to share in the capital costs of Los Banos-Gates; instead, both proposed to pay wheeling charges to PG&E. The Executive Director instructed all applicants to address the necessity of the Los Banos-Gates project.

In response, the second application included a substantially different definition of the COT Project. PG&E proposed to fullfil its MOU obligations by developing a set of principles for South-of-Tesla transmission requiring all COT Project participants to share in the cost of certain plant upgrades by 1991. Edison and SDG&E agreed to these principles, and all three IOUs included them in their second applications. The other COT Project participants, however, have not agreed to the principles, and DRA asserts that the principles do not provide the level of reliability called for in the MOU.

The Executive Director determined this lack of agreement to be a deficiency in the second application.

The question to be decided is whether the uncertainty surrounding the South-of-Tesla extension is sufficiently inhibiting to prevent our beginning the formal review process. We recognize that uncertainty is a feature of all large projects, and that uncertainty surrounding benefits of the COT Project will no doubt be given the lion's share of attention during the litigation phase of the proceeding.

One example of the many uncertainties linked to the project is the pricing and availability of power from the Northwest. We continue to be handicapped by the failure of the Bonneville Power Administration to promulgate a Long-Term Intertie Access Policy (LTIAP) that provides California with fair access to Northwest power at a reasonable price. We are deeply concerned that lack of closure on this issue will complicate greatly our consideration of the COT Project, and we will look very, very closely at all the facts pertaining to BPA policy during our deliberations on the cost-effectiveness of the project.

The South-of-Tesla extension is within the control of the applicants (together with the other project participants), and we will require the applicants to settle this basic aspect of project definition before we accept their application. We are optimistic that the strong signal we send today through this order will help spur all project participants in the direction of a consistent, well-defined project definition, and we hope to have such a definition before us within 60 days.

Let us be clear on the signal we intend to send by this order. We will not require the applicants to settle all possible areas of uncertainty regarding the COT project before we start the clock. We will require a consistent and well-developed project definition before we start the 180 days, and we will look during those six months with a critical eye at the many issues in this controversial application. We take today's action reluctantly, and re-affirm our commitment to rapid consideration of CPC&N requests, as envisioned by the PSA.

By this order, we affirm the Executive Director's rejection of the application.

Given the Executive Director's rejection of the application, and our affirmation of his action, there is no longer any matter pending before us, as PG&E's Reply correctly notes. Therefore, we will close this docket.

Findings of Fact

1. In the absence of a distinct appellate process under Government Code § 65943(c), Rule 85 of the Commission's Rules of Practice and Procedure is the appropriate procedure for challenges under the Permit Streamlining Act.

2. Applicants' appeals were filed in compliance with Rule 85.

3. The responsibility for preapplication review has been delegated to the Executive Director.

4. Completeness of an application at the beginning of the proceeding is critical because of the time constraints of the Permit Streamlining Act, which must be accommodated in conjunction with the Commission's statutory obligations under PU Code §§ 1705 and 1102.

5. As a means of discharging its obligations under the COT Project Memorandum of Understanding (MOU) to provide 1000 MW of firm bi-directional power between Tesla and Midway, PG&E included in its first application a new transmission line south of its existing Tesla substation (the Los Banos-Gates line), at an estimated cost exceeding $100 million.

6. Neither SDG&E nor Edison included the Los Banos-Gates line in their first applications, relying instead on wheeling arrangements, and this lack of consistency among the three IOUs regarding the definition of the COT Project was one reason why the first applications were determined to be incomplete.

7. In the second COT Project applications, the Los Banos-Gates line was omitted; instead, the three IOUs included South of Tesla principles, which provided that all COT Project participants would share in certain system upgrades by 1991.

8. Only the IOUs have agreed to the south of Tesla principles; there is no indication that the non IOU COT Project participants agree that the south of Tesla principles will provide a satisfactory level of firm bi-directional transmission service between Tesla and Midway, and DRA asserts that the principles will provide a level of service somewhat less than "firm."

9. Because there is no agreement among all COT Project participants on the South-of-Tesla extension, which is part of the COT Project MOU, there is no agreement on a definition of the COT Project.

10. Applicants have failed to provide a clear undisputed project description as required by GO 131-C.

11. Applicants' filings for certificates of public convenience and necessity were incomplete.

12. The Executive Director's determination of incompleteness was reasonable.

<u>Conclusions of Law</u>

1. The critical determination of completeness lies within the reasonable discretion of the Commission.

2. Once the Permit Streamlining Act clock starts, the Commission has only 180 days to reach a final decision from the date the applications are determined to be complete, or the project is "deemed approved."

3. The responsibilities of the Commission under the Permit Streamlining Act must be reconciled with the Commission's obligations pursuant to the Public Utilities Act.

4. The appropriate focus of a preapplication review is adequacy and completeness of the application, and not a critique of the merits of applicant's showing.

5. Given his concerns about a lack of project definition (more specifically the lack of clarity about applicants' MOU duties and obligations relative to the South of Tesla issue), the Executive Director properly determined the applications to be incomplete and there was no abuse of the discretion delegated to him by this Commission.

6. The determination of the Executive Director to reject the application(s) should be affirmed.

7. This docket should be closed, since there is no longer any matter pending before us.

O R D E R

IT IS ORDERED that:

1. The Executive Director's rejection of A.87-10-018 is hereby affirmed.

2. The docket in A.87-10-018 is closed.

This order is effective today.

Dated FEB 16 1988, at San Francisco, California.

STANLEY W. HULETT
President
DONALD VIAL
FREDERICK R. DUDA
G. MITCHELL WILK
JOHN B. OHANIAN
Commissioners

We will file a written concurring opinion.

John B. Ohanian and G. Mitchell Wilk
Commissioners.

I will file a written concurring opinion.

Frederick R. Duda

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

Victor Weisser, Executive Director

STATE OF CALIFORNIA GEORGE DEUKMEJIAN, Governor

BLIC UTILITIES COMMISSION
VAN NESS AVENUE
AN FRANCISCO, CA 94102-3298

November 13, 1987

John W. Busterud
Attorney at Law
Pacific Gas and Electric
P.O. Box. 7442
San Francisco, CA 94102

Re: A.87-10-018 California-Oregon Transmission Project

Dear Mr. Busterud:

We have reviewed the above appliction for a certificate of public convenience and necessity for the California-Oregon Transmission Project (COTP) and concluded that it is incomplete as submitted. Accordingly, we cannot at this time accept the application for filing pursuant to Government Code section 65943 and CEQA Guidlines section 15101.

As you know, Southern California Edison (Edison) and San Diego Gas & Electric (SDG&E) simultaneously filed separate applications as co-participants of this project. For reasons discussed below, we are notifying these applicants today that their applications are also incomplete and cannot be accepted for filing at this time. Upon submission of the requested materials, staff anticipates that the Commission will consolidate the review of the three applications into one proceeding.

In general, the deficiencies in PGandE's application are:

1) Failure to include enough information to allow the Commission to conclude that estimates of the availability and price of PNW power upon which this application relies are of sufficient reliability to satisfy Public Utilities Code §1102. In particular, we are concerned about the lack of a current BPA estimate of PNW power available for export to California, the absence of an analysis of this project in the context of BPA's Long-Term Intertie Access Policy, and unavailability of the IOU/Edison PNW computer model in a form that CPUC staff can readily access.

2) The lack of basis supporting the assumption in the application that the non-IOU project participants will agree that the south-of-Tesla transmission principles satisfy the MoU.

4) The incomplete description of the capacity exchange agreement between Edison and the Los Angeles Department

of Water and Power, the operating assumptions resulting from it, and the reason the other IOUs chose not to participate in it.

5) The lack of basis for estimates of the capital costs of the project in the muni-only scenario.

The specific information that would make your application complete includes the following major items:

1) A transmission agreement signed by all COTP participants, or alternatively, statements that the principles signed by the IOU's satisfies the MOU;

2) Delivery of SCE's Northwest Model in a generally used computer language (FORTRAN 77);

3) Filing of supplemental information containing findings, estimates, and forecasts made by BPA in their Final IDU EIS, a reconciliation of the differences between these BPA's results and those from the SCE model, and a discussion of the effect of the LTIAP chosen by BPA;

4) Provision of all available information pertaining to the entitlements exchange described in SCE's application and incorporated in all three IOU applications.

A list of the specific deficiencies is attached.

It is our sincere desire to have the CPUC review process for this project move as quickly as feasible. Accordingly, we will keep this application on the docket pending submission of the material requested, allowing the applicant and Commission staff the opportunity to proceed on all issues of the case not dependent on the missing information.

In order to discuss either the deficiencies identified in the attachment, our staff is available to meet with you at your earliest convenience. If you would like to schedule a meeting, please contact Mike Burke at (916) 322-7316.

Sincerely,

Victor R. Weisser
Executive Director

Attachment

cc: Mary Carlos
ALJ Carew
Jim Scarff
Mike Burke

ATTACHMENTS

PG&E's COTP CPC&N Application deficiency letter has two attachments. Each of the two attachments has three sections, organized according to the following outline:

Attachment 1 contains deficiencies from the May 8, 1987 letter.
This Attachment has three Sections:

Section 1: Utility-specific deficiencies
Section 2: EMA Tier II deficiencies
Section 3: Engineering deficiencies

Attachment 2 contains deficiencies from the October 1987 CPC&N Applications.
This Section has three Attachments:

Section 1: Utility specific deficiencies
Section 2: EMA new Tier II deficiencies
Section 3: Engineering deficiencies

In some instances, detailed references to specific sections of the Applicant's documents are shown, using the following coding conventions:

OA = Original Application
DL = Deficiency Letter
NA = New Applications

ATTACHMENT 1 - Section 1

PG&E - SPECIFIC DEFICIENCIES

The following list refers to those deficiencies identified in the May 8, 1987 letter that were not adequately addressed in PG&E's specific responses or in the October 1987 COTP CPC&N Application.

Deficiency 1. Cost of PNW surplus

a. Nonfirm energy

PG&E was notified that data specific to PG&E would be required to meet this deficiency, including PG&E's alternative cost. PG&E cites EMA study Section 3.4 for compliance. The Table in Section 3.4 that refers to utility data (e.g., Table 3-28) specifically leaves PG&E data on alternative cost blank. The information provided does not satisfy this deficiency item.

b. Capacity

PG&E was directed to provide the cost of the PNW surplus capacity used in support of PG&E's application. PG&E cites EMA Section 3.3 for compliance.

Section 3.3 is silent on the cost, with the possible exception of BPA's claim about its costs used for initially proposed SL-87. Given SL-87 is limited to 1350 MW, and this amount can be sold over the existing Pacific Intertie firm capacity of 5500 MW before COTP, the cost of the PNW surplus which will be sold over COTP is absent in this section. Furthermore, if PG&E assumes only BPA SL-87 surplus will be sold over COTP, PG&E should explain why no nonfederal sellers will make sales over COTP and why SL-87 will not be fully subscribed on the existing 5500 MW before COTP. (Reference: OA pg. A-5; DL pg. 1, NA Vol 1 sections 3.4 and 3.3)

ATTACHMENT 1 - Section 2

DEFICIENCIES IN EMA ECONOMIC ANALYSIS

Deficiency 1. P.U. Code Section 1102

The application cites EMA report Sections 3.3 and 3.4 for compliance. These sections fail to reflect increased cost, possibility of future increases and feasibility of contracts in the following ways:

1.1. The application claims that the price for the mix of services from the PNW will cost about 75% of the cost of a gas turbine (page 3-46). The application needs to show that the prices in fact do that compared to the costs of a gas turbine used in the EMA analysis separately each for PG&E, SCE and SDG&E. Further, some basis for the 75% is needed (e.g., comparison of historical prices to historical costs of CT, statements of PNW sellers that their future price limit is 75%).

1.2. BPA's SL rate applies to only 1350 MW of capacity and 725 aMW of energy. The application needs to explain why a schedule for 1350 MW applies to capacity sales in excess of 5500 MW (or whatever will be the firm carrying capacity of the existing lines before COTP), and applies to nonfederal sellers as well as BPA.

1.3. The application must explain why existing contract capacity/demand prices substantially exceed the projected prices for the COTP analysis.

1.6 EMA assumes the PNW capacity rate will be BPA's initially proposed SL-87 for a four month summer rate. This is to represent the feasibility of negotiating long term contracts under reasonable charges. To make this a credible claim, EMA must show why the current and proposed actual contracts with the PNW for capacity are substantially greater than the BPA assumed rate.

1.7 No analysis or data was presented on the effect of the Long Term Intertie Access Policy (LTIAP) in EMA's analysis. The application should provide analysis and data on the effect of the LTIAP on the COTP as required by P.U. Code 1102 including the effects on economy energy, firm capacity and energy purchases.

1.8 In Table 3-6, support is needed for the assumption that dependable hydro capacity in the summer is the same as in the winter. Support is needed for why the Canadian surplus will last in excess of 1500 MW past 2006/07. Support is needed for the assumption that the cost of this surplus is less than the proposed BPA SL-87 rate used in the analysis.

Deficiency 2.1 Capacity purchases by utility (OA pages 12 and 104; DL page 1; NA EMA 5.2.1.3 and Tables 5-90, 5-91, and 5-92)

The request was to provide the estimate of MW purchased by the municipal utilities in the EMA study. The answer refers to EMA section 5.2.1.3 and three tables. These citations do not contain an answer about the assumed MW of municipal utility purchases in the EMA analysis.

Deficiency 2.3 Capacity purchase assumption and the BPA IAP (OA pages 36 and 37; DL page 2; NA EMA 3.3 and 3.5)

The request was to reconcile the assumed capacity purchases over the COTP with the terms for capacity sales in the IAP, specifically Exhibit B and the way the IAP provides for firm sales. The answer provides considerable information on the absolute physical capacity amounts, along with a statement that the IAP should not be considered since the Administrator says the final LTIAP will not be anti-competitive.

The answer is responsive only in part. The physical capability and the IOUs opinion on how the LTIAP should be considered is clear. There is no reconciliation, however, between, on the one hand, the proposed LTIAP and Exhibit B, and, on the other hand, the assumptions in the EMA study on capacity sales.

Deficiency 3.1 Spot Capacity (OA page 23; DL page 2; NA EMA 3.1)

Applicant was asked to support the claim that capacity is a function of water years (e.g., more capacity is available in noncritical water years, rather than the alternative that the amount of capacity is not a function of water year but that whether the PNW asks for return of the energy is a function of different water years). The new study makes the same unsupported claim (EMA Section 3.1.3.4, page 3-13), and fails to provide any support.

Deficiency 3.2 Capacity from seasonal diversity (OA page 23; DL page 2; NA EMA 3.1)

Support is needed for the claim that resources in excess of demand in the Northwest Power Pool Area of 25882 MW exist in the summer of 1987. (EMA Section 3.1.8, page 3-17.) This should be reconciled with Table 3-1 which shows about 8000 MW of firm surplus in July 1986.

Deficiency 3.3 Duration of capacity (OA page 65; DL page 3; NA EMA 3.1)

Lack of support for the assumption that PNW surplus capacity will last 30 years was identified as a deficiency. The answer is EMA Section 3.1. This section develops the applicant's claim of surplus through 2005-6 for the PNW and 2006-7 for Canada. No support is given that these levels will not deteriorate over the life of COTP (now assumed to be 40 years).

Deficiency 4.1 Composite PNW capacity price (OA page 64; DL page 4; NA EMA 3.3)

Applicant was asked to support the basis for the capacity price used, with several specifics and examples identified. The applicant's answer to this deficiency item is EMA Section 3.3.

The answer does not address the deficiency item. The EMA study does not explain the reason to assume nonfederal prices will be the same as federal prices. The study does not show that nonfederal prices in existing and proposed contracts are equal to federal prices.

EMA does state that it uses a single composite price to represent a mix of capacity services, and that composite price will be on the order or 75% of the cost of a combustion turbine (EMA page 3-46). Support is needed for that assumption. For example, is the initial proposed SL-87 rate used in the EMA study on the order of 75% of the cost of a combustion turbine for PG&E? SCE? SDG&E? What is the cost of the surplus capacity to the PNW sellers? Is it less than the assumed price? Similar to the energy portion of the study, why is it more reasonable to use a single composite price for the capacity portion of the study and not so for the energy portion?

Deficiency 5.1 Energy over COTP (OA pages 16, 39 and 113; DL page 5; NA EMA 3.2.3 and Appendix I)

Applicant was asked to reconcile the estimated sales over COTP estimated by BPA and those in its own analysis. The answer is EMA Section 3.2.3 and Appendix I.

The response provides several clues to the reconciliation, but is deficient for the following reasons. First, the direction of the reconciliation varies between items (that is, some explain the difference, but some would make it worse). Second, the apparent magnitude of the reconciliation items does not explain the wide difference between studies. Third, some of the items would make for no difference between studies.

The following discussion addresses each specific explanation for a difference between studies and will help explain why the reconciliation is deficient. As the conclusion makes clear, if this is the applicant's best reconciliation and all there is, the applicant may so indicate. If more information is available, however, the applicant must make that clear at this time.

A. Differences in PNW load growth

On the surface this supports the applicant's claim. The effect on sales to California is unquantified, however, and the effect may go the other direction. For example, higher load in the PNW probably means that the PNW installs more resources. Southern California Edison has pointed out in other proceedings before the CPUC (SCE's General Rate Case) that if more resources are built in the PNW (even to meet PNW load growth), there will be more (not less) surplus capacity, and likely more (not less) surplus energy. Thus, the reason given in Appendix I may actually explain why the EMA study should show less (not more) energy than does BPA, since there is less load growth and less resource additions in the EMA study.

B. Differences in coal plants

The answer says that 1719 MW of added coal

resources are used in the EMA study, for extra energy of 1203 aMW. The answer fails to address that there is added load to be met by these resources, and what that capacity and energy load is. The net surplus is less than the gross amounts listed. The effect supports the direction of the EMA study results, but the magnitude is unclear.

C. Definition of California market

The differences in definition of the California market will explain why EMA estimates are 16% greater than BPA's. However, EMA's estimates are 153% more in 1995 and 2004 than are BPA's.

D. Gas prices

BPA uses higher gas prices. If California imports more when gas prices are higher due to greater benefits from the transactions, and more transactions being economic (e.g., being able to import even the most expensive PNW coal that lower gas prices do not support), than this reason would support EMA results being lower (not higher) than BPA. This reason does not support the difference in results.

E. BPA has higher energy prices

BPA has higher energy prices, but assumes that they are never more than 75% of California's decremental costs. There is always sufficient margin for California to import all that the PNW has to sell under that assumption. This reason does not explain any difference between studies.

G. COTP in-service date

EMA assumes that COTP is operational 5 months earlier than does BPA, out of a 40 year project (480 months). This affects 1991 energy only, but 1991 is the year of least difference between EMA and BPA. This reason does not explain the differences in 1995 or 2004.

Deficiency 7.1 Prices for PNW nonfirm energy (OA pages 13 and 83; DL page 6)

A. Derivation (NA EMA 3.4)

The new application abandons the 60% and 82% ratios for prices, and now uses a 50/50 share the savings as the base case. The applicant must support why this is a reasonable assumption. If the applicant wishes to assume a 50/50 split, the applicant must explain why hydro variable operating costs are not used for block 1.

Deficiency 7.2 Prices for Southwest nonfirm energy (OA pages 82-3; DL page 7)

A. Derivation (NA EMA 4.5.2)

The deficiencies for the derivation of the Southwest prices are very similar to those for the PNW prices. (See 7.1 (a) above). Support is needed for the very central claim that the prices are actually based on a 50/50 split. Support is needed for SDG&E's forecast that the off-peak price will be 0.93 of the on-peak price (page 4-59). Support is needed for SCE's ratio of 0.863. Marginal cost estimates in Table 4-45 must be corroborated by actual recorded marginal costs (e.g., system lambda, California Power Pool quotes). Prices in Table 4-45 must be adjusted for losses to be comparable to the marginal cost. Table 4-45 is based on 9500 BTU/kWh, while the estimated off-peak prices are based on 9000 BTU/kWh. The applicant should support the claim that the correct estimate of marginal cost in Table 4-45 is based on 9500, not 9000 (to the extent most of the Southwest energy is purchased off-peak), or a weighted average of 9500 and 9000 based on actual on- to off-peak imports.

The application must reconcile the claim that Tier II analysis is utility specific, with the calculation of the Southwest price on a non-utility specific basis. For example, in the on-peak period, if the PROMOD III runs show the average incremental heat rate for any utility in any snapshot year is in excess of 9500, the actual energy benefit is overstated when the price is computed based on 9500. Support should be provided for the assumption that gas will be the marginal fuel for the 40 year life of the COTP, and that the incremental heat rate will remain at 9500 and 9000, not declining over time as utilities reoptimize and modernize their own plant.

Support should be provided for the assumption that the SW price as a percent of decremental cost for each block declines over the life of COTP (Table 4-46 and 4-47), when the actual data shows it has been increasing in the 1980's (Table 4-45).

The CEC ER-6 sensitivity scenario should be supported by explaining why the gas price increases, but the coal prices in the Southwest do not (Tables 4-48 and 4-49).

B. Coal escalation rates (NA EMA 4.3.2)

The gas price escalation is 9.0% annually from 1989 to 2005 (Table 4-14) and 5.5% thereafter (Section 5.1.3). Coal prices escalate at 5.5% from 1991 to 2031 (Sections 3.4.2 and 4.5.2.2). The original deficiency asked the applicant to support the substantially different escalations in gas and coal to 2004, which by itself results in coal prices being dramatically lower than gas in 15 years. The new application fails to answer this deficiency.

ATTACHMENT I - Section 3

ENGINEERING DEFICIENCIES

The following Deficiency numbers refer to the Deficiencies identified in the original May 8, 1987 letter.

Deficiency 3. The Applicants did not provide the following data:

- Individual line ratings;
- Series capacitor ratings (continuous and 30 minute ratings);
- The specific element(s) that limit the transfer rating in a worst case scenario.

The Applications should provide this information for all 500 KV line sections between Malin and Midway.

Deficiency 5. A detailed discussion and analysis of the following was not provided:

a. Under frequency load shedding requirements;

b. Generation dispatch constraints/practices which differ from strict economic dispatch based on heat rates.

c. Effects of curtailment of Northern California hydro generation as required by the Pacific Intertie Agreement on loop flow curtailments.

Deficiency 6. The data provided does not include any detailed engineering studies to support the alleged reliability benefits.

Deficiency 7, 8 and 9. The responses provided refer to five reports by the PSSC. These reports lack sufficient detail to verify the results.

The Application is still void of substantial system engineering data. Copies of power flow and stability studies performed for the COTP should be provided including the following:

a. Base case load flow plots or printout for the California areas for each of the four base cases used in the most recent COTP stability studies.

b. A stability case for loss of Olinda substation (500 KV line to Tracy and the 500 KV to 230 KV transformer) without the islanding scheme and with conditions similar to the credible two line outage cases listed on page 87 of the Preferred Plan of Service and Power System Studies, March 1987.

c. Stability plots for cases Lsp 126 and 127 listed on page 87 of the Preferred Route Plan of Service, march 1987 report. Include plots of 500 KV voltages such as Devers and other 500 KV buses, NW and SW system angles, frequency plots, and series capacitor currents.

d. Frequency plots for case 1 of the Corridor Separation Report (loss of three project 500 KV lines).

e. A description of the NE/SE and NW/SW islanding schemes listing the circuits tripped.

f. Details on the various remedial actions schemes should be provided.

g. Existing and future transmission service commitments for all 500 KV line sections between Malin and Midway.

h. All studies or analysis performed to determine the future nomograms with and without COTP.

Deficiency 10 and 11. The response was inadequate. The requested information on outages should be provided on all line segments and projections of outage probability should be performed.

ATTACHMENT 2 - Section 1

PG&E OCTOBER 1987 COTP CPC&N APPLICATION

1. There is no analysis or discussion of the resale municipal utilities' (Anaheim, Riverside and MSR) willingness to absorb the IOU portions of the COTP in the Muni COTP option with only the Transmission Principles and "Intertie Firm" as opposed to the Los Banos-Gates line.

2. PG&E and SCE base their B/C analysis on the MUNI COTP as the only option to IOU participation. The SDG&E Application bases its analysis on the WITHOUT COTP option. The Applicants must clarify this apparent inconsistency in alternatives to IOU participation. If both options are possible, and since strategy benefits are different in the two options, the strategic benefits must be discussed and/or analyzed for each option separately.

3. Voltage support costs (Application, page 18)

The cost of system reinforcements required by the Transmission Principles Agreement do not include voltage support facilities. If voltage support facilities are required, what is the likely range of their cost, and what would be PG&E's proposal for the treatment of those costs? How likely is it that these facilities will be required? What set of factors might occur to make these facilities required? What other projects might be built which would satisfy the voltage support need?

4. Support is needed for the claim that the COT Project will allow PG&E to obtain more imported energy on peak, that is, that it will increase PG&E's ability to shape energy imports for use in periods of greater demand. (p.A-4)

5. The discussion of strategic benefits does not provide sufficient information to determine their validity. Any available quantification of these strategic benefits should be provided. If none are provided, then the application should contain a discussion of why these benefits are quantified for SCE and not for PG&E.

Many of the strategic benefits identified by PG&E to be attributable to their participation in the COPT also exist in the Muni Only COTP. The application should discuss only those strategic benefits attributable to PG&E participation.

No year by year summary of costs and benefits was provided.

The following statements (from Exhibit D - Strategic Benefits) must be clearly supported with references to PG&E's analysis or

EMA's:

a) It is estimated that this line capacity reserved for loop flow should be available 99% of the time when it is needed. (pp.D-1,2)

b) It is expected that PG&E's participation would prevent outages that would otherwise occur once every 8 to 20 years with a duration of 5 minutes to 2 hours and a magnitude of 0 to 1,000 MW. (pp.D-2,3)

c) WSPP pooling experience to date demonstrates that there is a market for such transmission services. (p.D-3)

d) PG&E's participation in the Project will help reduce the costs of this noneconomic commitment. (p.D-5)

6. Provide the basis for the projection of revenue requirements for PG&E's share of the Project that is shown on p.G-2. Why is this projection only for 12 years?

7. The "subsequent transmission studies" referred to on p. 16 of the application must be clearly identified and provided. Do they correspond to the material included in Exhibit K as "Transmission Studies"?

8. Additional transmission facilities (Application, page 16)

The Application states that

> If PG&E or any of the signatories to the Principles determine at a later date that additional facilities need to be installed to meet their transmission service requirements, PGandE may propose to build further reinforcements.

An indication of what these additional facilities might be, and their cost, must be provided, along with the types of factors that might occur to make these additional facilities required. Assessing the cumulative impact of the COTP project includes assessing the potential for these other additional facilities. The application should indicate whether at this time it appears that a CPCN would or would not be required from the CPUC for these additional facilities.

9. Provide the basis for the assumption that the benefits and costs of the planned Table Mountain dynamic voltage support (DVS) device would be mutually shared (50%) with the DC Intertie facility, subject to negotiations. What parties are involved with those negotiations? What is the status of those

negotiations? (pp.I-3,4)

10. Provide justification for the use of a 2 mill minimum saving level for economy transactions in EMA's analysis (page 5-2) with consideration given to losses, wheeling charges and the 15% markup used in the PNW and SW models.

11. Provide justification for the assumption in EMA's analysis and/or model that a utility will first provide transmission service to another utility to enable a lower cost economy energy transaction to occur instead of using its own transmission capacity to maximize profits by selling economy energy.

ATTACHMENT 2 - Section 2

EMA STUDY DEFICIENCIES

1. SCE-LADWP exchange (EMA Section 2.4)

The EMA analysis is based on the SCE-LADWP exchange of transmission entitlements.

The application must clarify whether PG&E and SDG&E take their shares of the exchange under the California Power Pool agreements, and whether the EMA analysis assumes they take their shares or not. The application cannot be accepted until the CPUC staff is provided full information on the details of this exchange. SCE claims that their case with the exchange is the "conservative" case. If that is true, this claim must be supported. SCE has a positive benefit to cost ratio for its participation in COTP given the entitlements exchange; without the exchange are we sure the B/C declines?

2. Key Economic Assumptions (EMA Section 4.1, Table 4-1)

Support is needed for the utility discount rates. The assumed capital structure and cost of funds for each component must be provided.

3. WAPA Resources - (Section 4.2 and 5.1.5)

EMA's analysis lacks sufficient discussion and workpapers describing the treatment and modeling of WAPA/PG&E/TANC energy and capacity amounts. How the modeling treatment correlates to the various contractual provisions and operating practices including pricing provisions and curtailment practices should be explained. The Applications should also explain how the PROMOD outputs were adjusted to obtain the figures in Table 5-2 through 5-13.

4. Analysis (EMA Section 5.0)

The application should justify the use of a 2 mill minimum saving level for economy transactions in EMA's analysis (page 5-2) with consideration given to losses, wheeling charges and the 15% markup used in the PNW and SW models.

5. Provide justification for the assumption in EMA's analysis and/or model that a utility will first provide transmission service to another utility to enable a lower cost economy energy transaction to occur instead of using its own transmission capacity to maximize profits by selling economy energy.

6. Provide justification for the different assumptions and methodology used to estimate wholesale and retail revenue impacts between PG&E and SCE. Explain why SCE could not reduce its charges for sales of capacity in order to compete with PNW suppliers (pages 5-123 through 5-129).

7. No documentation of SCE's transmission rates were provided in the EMA or SCE analysis.

8. Page 4-33 states "For internal planning purposes, SCE assumes that the maximum loop flow without COTP is 800 MW, and 1200 MW with the COTP. As such, there is no such reduction in loop flow on the two existing AC lines (2/3 of the 1200 MW with the COTP is 800 MW, the same loop flow as without COTP". In quantifying the Strategic Benefits due to reduced loop flow, however, 900 MW of loop flow with COTP was assumed.

This discrepancy should be explained and substantiated with workpapers.

9. Provide a clear explanation of the estimated cost sharing for South of Tesla reinforcements. Are the annual collections from SCE, SDG&E and SCPA to be proportionate to their shares of Midway-Tesla transmission? Are the annual collections designed to recover all of PG&E's expenses? If not, then what portion? Do these arrangements change if the Los Banos-Gates project is found to be necessary?

10. Illustration 5-1 of the EMA Cost Effectiveness Report does not represent correctly the PROMOD multi-area modeling of California. CVP and S-WAPA are not separated out. Provide a corrected Illustration showing the modeled interconnections between the 12 areas.

11. Neither the CPCN applications nor the PROMOD user manual document sufficiently the monitoring of critical interfaces between areas. Specifically, documentation is lacking describing whether, in the case of two or more tie lines passing through an interface, if each tie separately, or only the total capacity through the interface is not to be exceeded.

Provide justification to support the claims that the PROMOD multi-area modeling on a state-wide basis captures current utility practices and economic effects for each utility.

12. Capital Cost (Section 5.4)

The total capital cost is estimated at $ 465,992,000. This consists of four components: Direct Cost "forecasted" by RMI, Indirect Cost, AFUDC/IDC, and Line Outage. The report does not provide adequate references to specific workpapers on Direct Cost and Indirect Cost. How did RMI/IOUs arrive at these figures? Please provide all necessary documents.

13. Cost of South of Tesla Reinforcements (Section 5.4.6)

EMA assumes that the costs South of Tesla will be expensed and not capitalized. The rational for this must be explained. If this is not usual ratemaking procedure, the application must be based on ratebasing the investment and show the impact on the project.

14. Resource Plans (EMA Sections 4.4.2 and 4.4.3)

The resource plans without COTP must be provided. Also, energy resource plans (or if not plans, at least energy balances which result from the adopted resource plans) must be provided with and without COTP.

15. Cost to IOUs (Section 5.4)

From the analysis, the costs to IOUs can be summarized as follows:

	Table 5-122 Base Case	Table 5-124 Replacement Substation	Table 5-128 Revenue Requirements incl. Sub Replace cost
PG&E	$129,378,000	$192,300,000	$183,878,000
SCE	$ 95,600,000	$165,380,000	$143,800,000
SDG&E	$ 18,233,000	$ 26,920,000	$ 26,330,000

Please demonstrate, using an example, how the revenue requirements (including the substation replacement costs) were derived.

16. Fuel Price Forecasts. (Section 4.3, pp. 4-16 through 4-28.)

No explanation is given for the assumption that the appropriate marginal gas price forecast is a weighted average of the three IOU's marginal gas price forecasts. Separate price forecasts are used for other fuels, such as coal. Since the IOU's differ as gas buyers (e.g., PG&E and SDG&E are combined gas and electric utilities; SCE is not), the basis for using a weighted average marginal gas price forecast must be supported.

17. Firm contracts (Table 4-52)

The application must explain why the firm contracts listed in Table 4-52 cannot be carried over each owner's share of the existing Pacific Interties.

A further explanation is needed of the forecast price for the firm energy (on what are the forecasts based) and the assumed avoided cost that is avoided by this firm energy (along with an explanation of the assumptions used to estimate the assumed avoided cost for firm energy).

18. Provide the basis for the assumption that the additional cost of generating the energy not received (due to the 3.5% loss factor applied to the net flow of California economy energy north to south or south to north) was split equally among the buyers and sellers of the net California economy energy flow. (Section 5.1.5.2, p.5-61)

ATTACHMENT 2 - Section 3

ENGINEERING DEFICIENCIES

1. A description of the reinforcements of the transmission system south of Tesla to meet the projected COTP transmission service obligations and the needs of the COTP participants including SDG&E was not provided. No detailed engineering, powerflow or stability studies have been provided to determine the existing transfer capacity after reinforcements, minimum transfer capacity required for muni acceptance, and the amount of expected transmission service commitments and their justification.

2. A detailed description and justification of each of the interconnection flow limits in EMA's Illustration 5-1 was not provided. Include a listing of the various transmission service commitments on each path. Explain how EMA models the above correctly including the effects of counter scheduling.

(END OF APPENDIX A)

A. 87-10-023
D. 88-02-030

JOHN B. OHANIAN AND G. MITCHELL WILK, Commissioners, Concurring:

We join the majority in this decision with some reluctance, and do so only because we believe that agreement on the South-of-Tesla issue is an essential prerequisite to starting the clock. We are very concerned that the parties to this case (both DRA and the applicants) have used the provisions of the Permit Streamlining Act to front-load this proceeding and begin litigating the merits of the project before we have even accepted the application. Were it not for the South-of-Tesla issue, we would accept this application and let the process decide the merits.

The PSA is one of the few procedural spurs to expediting the CPC&N process, and we support it fully because we believe that delay in either granting or not granting a certificate hurts the applicants (who may waste time and effort in planning a project that will never be built), the ratepayers (who may lose some of the benefits of a delayed, cost-effective project), and the Commission (whose staff and support services must handle the extra workload of lengthy proceedings). We recognize the temptation on the part of the DRA to use the pre-application phase as a lever to pry more information out of the applicants, but this runs counter to the spirit of the PSA and we do not support the DRA's attempt to use the PSA in this way. The deficiencies noted by the Executive Director in his rejections, with the sole exception of South-of-Tesla, seem to us to speak to the merits of the project rather than to filing requirements.

The applicants also bear a portion of the blame for the delays in this case. We see very little evidence that the utilities have made strenuous efforts to comply with the deficiencies listed by the Executive Director. Had the utilities done so, we might have avoided the time-consuming necessity of this appeal. If this lack of cooperation continues during the litigation phase of this case, the applicants' burden of proof will, it seems to us, be very difficult to meet.

The other project participants (the "Munis"), though not before us as applicants, should nevertheless be aware that we will oppose this project unless we are convinced that it meets the requirements for a CPCN, and cooperation from the Munis in this proceeding will likely be essential to meeting the applicants' burden of proof.

Finally, we join the majority in its concern regarding the policies of BPA, and if anything we feel even more strongly that BPA's proposed pricing policies undermine fair access to northwest power, and thus are a disservice to Californians and will weigh heavily in our final opinion regarding the cost-effectiveness of the COT Project.

JOHN B. OHANIAN, Commissioner

G. MITCHELL WILK, Commissioner

February 16, 1988
San Francisco, California

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FREDERICK R. DUDA, Commissioner, Concurring

This decision resolves PG&E's appeal from the Executive Director's second rejection of its COTP application. The Commission's Division of Ratepayer Advocates (DRA) believes that the resubmitted application is incomplete because it does not contain information sufficient to enable the Commission to adequately resolve certain issues raised by the project application. Because the Commission agrees that the resubmitted application is incomplete with regard to the issue of project definition, a deficiency noted in the rejection of the initial application, it properly rejects the resubmitted application.

Although the majority reaches the correct result in this case, I believe its decision should have directly addressed certain issues raised concerning the Permit Streamlining Act (Government Code Section 65920 et. seq.) instead of ducking the issues by relying solely on the failure of the resubmitted application to address concerns raised in the initial rejection letter. I feel that the approach taken by the majority leaves an unnecessary ambiguity as to our willingness to take full advantage of the information gathering opportunities provided by the Permit Streamlining Act.

In appealing the second rejection of its COTP application, Edison argues that review of its resubmitted application must be limited to reviewing materials submitted in response to the Executive Director's original rejection letter, which included a list of deficiencies in the first application. In other words, in Edison's view the Executive Director may not look beyond the question whether the original deficiencies have been cured by the resubmitted application. Similarly, PG&E and SDG&E accuse the Commission of creating a regulatory moving target.

I believe these arguments unfairly criticize DRA for seeking additional information before making a determination as to the completeness of the resubmitted application. DRA's information gathering efforts fall squarely within both the letter and the spirit of the Permit Streamlining Act.

Government Code Section 65943(a) expressly provides for a second determination of the completeness of an application resubmitted after initial rejection on grounds of incompleteness. If this second determination is not made within 30 days, the resubmitted application is deemed to be complete. If the resubmitted application is determined not to be complete, the agency's determination of incompleteness must specify those parts of the application which are incomplete, and must indicate the manner in which they can be made complete, including a list and thorough description of the specific information needed to complete the application. The applicant is required then to "submit materials" to augment its application in response to the list and description.

Government Code Section 65943(b) provides that, no later than 30 days after receipt of the submitted materials, the agency must determine in writing whether the submitted materials are complete. If the written determination is not timely made, the application together with the submitted materials is deemed to be complete. At this juncture, if the agency has determined that the application, together with the submitted materials, is not complete, the agency must provide a process for the applicant to appeal that decision in writing to the governing body of the agency. (Government Code Section 65943(c)).

Under the Permit Streamlining Act, an agency has two distinct opportunities to request an applicant to provide additional information necessary to cure deficiencies in the application before it must finally determine whether the application is complete. First, if the agency determines that an initial application is incomplete it must inform the applicant of any deficiencies so that the applicant can attempt to cure those deficiencies in a resubmitted application. Second, if a resubmitted application is received, and the agency determines it is also incomplete, the agency must again inform the applicant of any deficiencies so the applicant can attempt to cure these deficiencies with additional submitted material. Once any additional material is received in response to the second list of deficiencies, the agency must then stop asking for more information and make its determination whether the application, as supplemented, is complete.

This several step process is necessary to balance the interests of applicants in having their applications considered on their merits and the interests of agencies in having sufficient information available to enable them to evaluate the merits of the application. The opportunity for an agency to notify an applicant that a resubmitted application is deficient is especially important where, as in the present case, the resubmitted application is substantially different from the initial application.

In addition to my criticism of the majority's discussion of the Permit Streamlining Act issue, I feel the need to express my concern with one other deficiency in the majority opinion. Because the Commission believes that the application is deficient with regard to the issue of project definition, it properly rejects the resubmitted application as incomplete. I believe, however, that the majority should have taken the opportunity presented by this decision to articulate more clearly its concerns about the utility's showing with regard to a number of other critical issues and to clarify certain questions we believe should be addressed head-on.

I would have added the following language to the adopted decision, just before the Findings of Fact, as follows:

"Notice of Need For An Adequate Record

Once the application is accepted, the Commission expects the project proponents to fully develop the record in this proceeding. We concur with the basic concerns of our Executive Director expressed in his letter of November 13. We fully believe that if the Commission is to make an informed decision on the merits, the proponent utilities must address in detail the following four questions:

1. What is the agreed upon project description?

2. What quantity of energy is available at what price from the Northwest, and what uncertainties should project proponents attach thereto?

3. How certain can we be that the addition of the COTP will not reduce the reliability of the western area power grid? (What is the likelihood that a 3-line failure will compromise the overall reliability of the overall western electricity system?)

4. What criteria are project proponents using to evaluate reliability (capacity) benefits of the COTP? (Are these reliability criteria appropriate or consistent with our generation planning reliability criteria?)

These are fundamental questions which the Commission believes must be adequately answered by project proponents before an appropriate decision on the merits can be reached. Accordingly, the Commission takes this opportunity to place the proponent utilities on notice that without an adequate showing on these issues, the Commission will be faced with the prospect of denying the COPT applications for lack of sufficient evidence."

Frederick R. Duda

Frederick R. Duda, Commissioner

February 16, 1988
San Francisco, California

It follows from the time constraints of the PSA and the substantial responsibility of the Commission under the Public Utilities Act, that the critical determination of completeness must lie within the reasonable discretion of the Commission. The Legislature has apparently recognized this logic in electing to leave the determination of completeness to the agency's discretion. The only pertinent requirement of the Act is that each agency prepare an "Information and Criteria List" to help inform applicants of information that will be necessary (Gov't. Codes §§ 65940-41). The Commission adopted such a list in 1979 (1 CPUC 2d 166 (1979)). The Legislature did not elect to prescribe to agencies what information they must obtain, but was silent on the substantive contents of such lists. The Legislature further did not elect to dictate to the Commission that the Information and Criteria List is the exclusive standard to be applied in determining completeness. We therefore conclude that the Commission has been left to exercise its discretion in these matters, so long as it is exercised reasonably. Our standard of review must recognize the realities imposed by the Public Utilities Act and the PSA and must also reflect the fact that the burden of proof justifying the issuance of the certificate is clearly on the applicant.

We turn now to the specific arguments raised by PG&E in contesting the Executive Director's determination.

III. PG&E's Grounds for Appeal

A. Introduction

PG&E makes three arguments in support of its appeal. First, it asserts that it has met all applicable legal requirements. Second, it maintains that the Executive Director's actions effectively hold PG&E "hostage" to events beyond its control. Finally, PG&E maintains that the review process used in this instance constitutes a regulatory "moving target," which subverts the PSA.

B. The Application Satisfies all Applicable Legal Requirements.

PG&E maintains that Public Utilities Code Sections 1001, 1003, 1004, and 1102 specify the totality of information to be reviewed by the Commission in a CPC&N proceeding, and that the Commission's implementing General Order (GO) 131-C is the standard for gauging completeness of a particular CPC&N application. PG&E believes that its application meets or exceeds all GO 131-C filing requirements (A.87-10-018, pp. 3-5), and provides a sufficient basis for the Commission to initiate formal review proceedings.

Within this context, PG&E challenges the validity of the various deficiencies noted in the Executive Director's letter. For example, it asserts that rejection based on inadequate Section 1102 analysis[2] is misplaced, because Section 1102 is not a threshold standard for measuring the completeness of A.87-10-018. According to PG&E:

> "...If the Commission wishes to include Section 1102 information as a specific filing requirement, it should do so by amending General Order 131-C. Otherwise, the information required by Section 1102 should be adduced during the hearing process." (PG&E Appeal, p. 11.)

PG&E asserts that § 1102(a) also requires the Commission to perform its own analysis of the forecast cost of electricity, as well as other factors bearing on Northwest power purchases, prior to issuing the COT Project CPC&Ns. Thus, assuming PG&E's application

2 Section 1102 requires PG&E in this instance to supply the Commission with "sufficient 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." (Public Utilities Code § 1102(a).)

contains "sufficient reliable information" to enable the Commission to discharge its § 1102 obligations, in PG&E's view the statutory language cannot be used as a threshold bar to entertaining the application.

Another noted deficiency was Edison's failure to translate its Pacific Northwest (PNW) computer models into FORTRAN 77. PG&E argues it has no control over this situation, and furthermore, that any failure to provide access to computer models prior to acceptance of an application does not constitute a valid deficiency under GO 131-C.

PG&E also challenges the Executive Director's determination that A.87-10-018 is deficient in providing no support for its assumption that non investor owned utility (IOU) project participants will agree that the South of Tesla Transmission Principles satisfy the COT Project Memorandum of Understanding (MOU).

The MOU requires PG&E to provide up to 1,000 MW of firm bi-directional transmission service between its Tesla and Midway substations for certain project participants. PG&E's initial application included provision for a system upgrade (the Los Banos-Gates Project) to meet this requirement. The initial application was found deficient, partly because this provision was inconsistent with the initial COT Project applications of Edison and SDG&E. In response, PG&E included in its second application a set of transmission "principles" which require it to install certain noncertifiable transmission system reinforcements between Tesla and Midway by 1991. PG&E, Edison, and SDG&E agreed to these principles in October 1987, but the Transmission Agency of Northern California (TANC) and the Southern California public agency participants have not agreed to them.

PG&E believes the facilities and service to be provided under the principles fully satisfy its obligations under the MOU. Further, it asserts that the lack of formal agreement by TANC and the Southern California public agency participants should not prevent the Commission from initiating the review process or accepting A.87-10-018.

PG&E also regards as unmerited the rejection of A.87-10-018 based on Edison's failure to provide adequate information concerning an exchange agreement between Edison and the Los Angeles Department of Water and Power (LADWP). It believes that questions about its own lack of participation in this exchange agreement are irrelevant to its participation in the COT Project. It also contends that the Public Utilities Code and GO 131-C do not allow for rejection of A.87-10-018 simply because an applicant fails to explain its reasons for not entering into an exchange agreement which does not impact its system or its ratepayers.

PG&E also believes that other alleged deficiencies are legally invalid, inappropriate challenges to assumptions or methodologies (more appropriately considered in hearings), requests for information already provided, misundertandings, or "additional prediscovery data requests." (PG&E Appeal, pp. 16-17.)

C. PG&E Asserts its Application is Being Held Hostage to Events Beyond its Control.

First, PG&E challenges the Executive Director's determination that its application is incomplete because TANC and the public agency participants have not formally agreed to the Tesla to Midway Transmission Principles; PG&E believes such an outcome effectively places those non IOU participants in a position of power to forestall acceptance of A.87-10-018 indefinitely . Moreover, it believes that the Executive Director's requirement for a formal agreement among these parties will place PG&E at a disadvantage at the bargaining table.

Second, PG&E opposes the requirement that BPA issue its final Long-Term Intertie Access Policy (LTIAP) prior to acceptance of A.87-10-018, consistent with its view that California utilities should not wait to pursue access to Northwest power for further refinements to the LTIAP. PG&E also notes that nothing in Section 1102 or GO 131-C requires publication of the LTIAP as a condition to acceptance of A.87-10-018.

Third, PG&E reiterates that it has no control over either the format of Edison's PNW computer model or the exchange agreement between Edison and LADWP.

D. Subversion of the Permit Streamlining Act

PG&E believes that review of its second application should be limited to determining whether deficiencies in the first rejection letter have been remedied. It challenges the review process which preceded rejection of A.87-10-018, because it believes issues such as (1) signed agreements for South of Tesla service and (2) analysis of BPA's final LTIAP, should have been raised during the first review (PG&E Appeal, pp. 21-22). It believes the review process employed in this instance constitutes a "regulatory moving target," in violation of the Commission's specific obligations under the PSA (Govt. Code § 65943(a)).

PG&E also questions the role of the Division of Ratepayer Advocates (DRA) in the review process, because it perceives DRA lacks objectivity in carrying out this task.

III. DRA's Response to PG&E's Appeal

A. Introduction and Preliminary Matters

On January 25, 1987, DRA filed lengthy formal comments responding to the appeals of PG&E, Edison, and SDG&E. As a preliminary matter, DRA objects to the notion that PG&E's application has been "rejected," since the Commission has kept the A.87-10-018 docket open in order to allow the parties the opportunity to proceed on all issues of the case which are not dependent on the missing information. DRA submits the only effect should not wait to pursue access to Northwest power for further refinements to the LTIAP. PG&E also notes that nothing in Section 1102 or GO 131-C requires publication of the LTIAP as a condition to acceptance of A.87-10-018.

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DRA also reports that PG&E has stopped responding to DRA data requests, pending the outcome of this appeal.

Furthermore, DRA notes that if the Commission grants PG&E's appeal, effectively finding its application to be complete, the clock will start to run under PSA and the Commission will have only 180 days to reach a decision on the merits.

Finally, DRA argues that the COT Project requires close scrutiny in view of the sensitivity of applicants' cost effectiveness assumptions. It notes that the applicants have relied on nontraditional benefits (i.e., increased system stability and reliability) in order to bolster their cost-effectiveness analysis. Thus, the missing information can be of critical importance, as it relates to the analysis of a single benefit which could tip the scales against cost-effectiveness.

B. The Missing Information

1. In General

DRA asserts that PG&E's application suffers from multiple deficiencies, over and above the major items discussed in the appeal. It calculates 40 common uncorrected deficiencies from the initial applications, 20 common deficiencies arising from the second applications, and 17 deficiencies specific to PG&E's application.

2. PU Code Section 1102

A primary concern is the failure of PG&E to provide "sufficient reliable information" of PNW power prices, as required by Public Utilities Code § 1102. DRA notes a substantial conflict between applicants' current estimates of PNW capacity and energy availability and BPA's own most recent lower (by 1,500 Gwh) estimates of energy export sales. DRA also indicates that BPA is currently revising its estimates downward to mitigate certain fishery impacts. Applicants' current estimates are also much higher than available Energy Commission and QF industry forecasts.

DRA points to certain ongoing litigation which may require BPA to further mitigate fishery impacts associated with increased exports of hydroelectric power for COT and other projects, raising substantial questions that the COT Project is no longer cost effective (DRA Comments, p. 8). According to DRA:

> "BPA's revised final EIS which will contain its final mitigation proposals is scheduled for release in mid-March. Pending release of that document, the uncertainty surrounding fishery mitigation makes it impossible for the Commission to satisfy the mandate of PU Code § 1102." (DRA Comments, p. 8.)

DRA also maintains that the LTIAP, now scheduled for release in mid-April 1988, has a major bearing on the COT Project economic analysis. The magnitude of the potential BPA actions is so great, in DRA's view, that they could eliminate nearly all energy and capacity benefits from the project. DRA states:

> "The utilities have argued that they should not have to wait for BPA to issue its final LTIAP. But this is precisely the policy advocated by PU Code § 1102--that California utilities not commit themselves to expensive investments in transmission lines to the Northwest until BPA has made some commitment regarding price and availability of power." (DRA Comments, p. 9.)

Finally, DRA believes the Executive Director was correct to identify as a deficiency the fact that Edison's PNW computer model, used by all applicants, is not yet available to DRA in a readily known computer language. Edison's conversion of the model to FORTRAN will not be completed until mid-February, according to DRA. DRA cites the short lead time between acceptance of the applications and the due date for DRA testimony as further justification for refusing to allow the PSA clock to start.

3. <u>The Project South of Tesla</u>

As previously noted, PG&E's first COT Project application contained a request to build a new line south of the Tesla substation (Los Banos-Gates Project). The Los Banos-Gates Project is included in TANC's EIR at a cost of approximately $100 million. However, Edison and SDG&E did not include Los Banos-Gates in their initial applications, and the Executive Director noted this inconsistency as a deficiency in those applications.

In their second applications, all three IOUs sought consistency by agreeing to a set of principles regarding wheeling south of Tesla that would, according to DRA, provide a level of service somewhat less than "firm," albeit obviating the need for Los Banos-Gates.

DRA believes the Executive Director correctly refused to accept the applications in the absence of formal agreement by the non-IOU participants, and solely on the basis of the IOUs' representations that the non-IOU participants would ultimately agree to these principles. DRA points to PG&E's $100 million exposure in the event of litigation over the principles. DRA believes "this dispute between COTP participants as to what the COT Project is must be settled by all participants before the applications can be considered complete." (DRA Comments, p. 12.)

4. <u>Lack of Supporting Data</u>

DRA also believes the IOU applications are deficient for lack of any baseline studies of system reliability, given the claim that system reliability is a major project benefit.

5. **<u>Failure to Disclose Relevant Information Re Edison-LADWP Transmission Capacity Exchange Agreement</u>**

Edison and LADWP have agreed to exchange 820 MW of transmission capacity on lines to the PNW, partially conditioned on the construction of the DC upgrade. Edison would give LADWP 320 MW of Edison's capacity on the existing AC line and in exchange LADWP would give Edison 500 MW of capacity on the DC upgrade for a 35-year period. DRA asserts that Edison would thus gain an additional 400 MW of firm transmission capacity to the PNW even if the COT Project were not constructed. PG&E's application, like those of Edison and SDG&E, reflects Edison's participation in this exchange.

DRA believes the Commission needs to know about feasible alternatives and why they were rejected by the IOUs, in order to gauge project cost effectiveness. DRA believes that PG&E's deficiency, correctly noted by the Executive Director, is its failure to explain its own relationship to this exchange (as a party to the Pacific Intertie Agreement, PG&E needed at least to approve Edison's participation in the exchange agreement, according to DRA).

6. <u>The Muni-Only Baseline</u>

PG&E and Edison measure the benefits of the COT Project against a "muni-only baseline," which assumes that if these IOUs do not participate in the project, the munis will proceed to build the line by themselves.[3]

DRA believes PG&E and Edison's assumptions regarding the muni's construction costs are defective in that they have simply assumed that construction costs for the munis will be the same as for the IOU-muni combination. In DRA's view, this exaggerates the attractiveness of the muni-only option and consequently exaggerates the cost effectiveness of the COT Project. DRA believes the Executive Director correctly noted this as a deficiency.

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3 DRA notes that under the conventional "no project" alternative baseline, PG&E's and Edison's costs of participation exceed benefits by over $200 million (DRA Comments, p. 18).

Act. We do not believe, however, that we have the authority under the statutes to delay acceptance of an application in order to give ourselves and our staff greater time to consider the merits of a project. We believe instead that the applicants bear the burden of convincing us of the merits of their proposal during the 180 days allowed.

We do believe that we cannot reasonably accept an application for a project that is not yet well-defined, for to set a precedent of doing so would threaten to introduce chaos into our already strained review process. The 180-day limit imposed by the PSA on our deliberations must reasonably assume that we have a project to deliberate. Otherwise, neither our staff nor interested parties would have a fair chance to consider the merits of a proposal that is open to significant revision <u>after</u> the review process has begun. This inability of parties to examine fully a revised proposed project might well lead us to refuse the granting of a CPC&N, but only after a great deal of time and effort has been wasted by our staff and interested parties. The wasting of time was clearly not the intent of the PSA, nor is it to the benefit of California ratepayers.

We come then to the project definition issue that speaks directly to whether we can reasonably accept this application and set the 180-day clock ticking--the South-of-Tesla extension. The memorandum of understanding (MOU) requires PGandE to provide 1000 MW of firm bi-directional power between Tesla and Midway. In its initial application PG&E proposed to meet this obligation by constructing a ~~system~~ new transmission line upgrade known as the Los Banos-Gates project. Neither SDG&E nor Edison proposed in its application to share in the capital costs of Los Banos-Gates; instead, both proposed to pay wheeling charges to PG&E. The Executive Director instructed all applicants to address the necessity of the Los Banos-Gates project.

In response, the second application included a substantially different definition of the COT Project. PG&E

proposed to fullfil its MOU obligations by developing a set of principles for South-of-Tesla transmission requiring all COT Project participants to share in the cost of certain plant upgrades by 1991. Edison and SDG&E agreed to these principles, and all three IOUs included them in their second applications. The other COT Project participants, however, have not agreed to the principles, and DRA asserts that the principles do not provide the level of reliability called for in the MOU.

The Executive Director determined this lack of agreement to be a deficiency in the second application.

The question to be decided is whether the uncertainty surrounding the South-of-Tesla extension is sufficiently inhibiting to prevent our beginning the formal review process. We recognize that uncertainty is a feature of all large projects, and that uncertainty surrounding benefits of the COT Project will no doubt be given the lion's share of attention during the litigation phase of the proceeding.

One example of the many uncertainties linked to the project is the pricing and availability of power from the Northwest. We continue to be handicapped by the failure of the Bonneville Power Administration to promulgate a Long-Term Intertie Access Policy (LTIAP) that provides California with fair access to Northwest power at a reasonable price. We are deeply concerned that lack of closure on this issue will complicate greatly our consideration of the COT Project, and we will look very, very closely at all the facts pertaining to BPA policy during our deliberations on the cost-effectiveness of the project.

The South-of-Tesla extension is within the control of the applicants (together with the other project participants), and we will require the applicants to settle this basic aspect of project definition before we accept their application. We are optimistic that the strong signal we send today through this order will help spur all project participants in the direction of a consistent, well-defined project definition, and we hope to have such a definition before us ~~shortly~~ within 60 days.

Let us be clear on the signal we intend to send by this order. We will <u>not</u> require the applicants to settle all possible areas of uncertainty regarding the COT project before we start the clock. We <u>will</u> require a consistent and well-developed project definition before we start the 180 days, and we will look during those six months with a critical eye at the many issues in this controversial application. We take today's action reluctantly, and re-affirm our commitment to rapid consideration of CPC&N requests, as envisioned by the PSA.

By this order, we affirm the Executive Director's rejection of the application.

Given the Executive Director's rejection of the application, and our affirmation of his action, there is no longer any matter pending before us, as PG&E's Reply correctly notes. Therefore, we will close this docket.

<u>Findings of Fact</u>

1. In the absence of a distinct appellate process under Government Code § 65943(c), Rule 85 of the Commission's Rules of Practice and Procedure is the appropriate procedure for challenges under the Permit Streamlining Act.

2. Applicants' appeals were filed in compliance with Rule 85.

3. The responsibility for preapplication review has been delegated to the Executive Director.

4. Completeness of an application at the beginning of the proceeding is critical because of the time constraints of the permit Streamlining Act, which must be accommodated in conjunction with the Commission's statutory obligations under PU Code §§ 1705 and 1102.

5. As a means of discharging its obligations under the COT Project Memorandum of Understatnding (MOU) to provide 1000 MW of

firm bi-directional power between Tesla and Midway, PG&E included in its first application a new transmission line south of its existing Tesla substation (the Los Banos-Gates line), at an estimated cost exceeding $100 million.

6. Neither SDG&E nor Edison included the Los Banos-Gates line in their first applications, relying instead on wheeling arrangements, and this lack of consistency among the three IOUs regarding the definition of the COT Project was one reason why the first applications were determined to be incomplete.

7. In the second COT Project applications, the Los Banos-Gates line was omitted; instead, the three IOUs included South of Tesla principles, which provided that all COT Project participants would share in certain system upgrades by 1991.

8. Only the IOUs have agreed to the south of Tesla principles; there is no indication that the non IOU COT Project participants agree that the south of Tesla principles will provide a satisfactory level of firm bi-directional power between Tesla and Midway, and DRA asserts that the principles will provide a level of service somewhat less than "firm."

9. Because there is no agreement among all COT Project participants on the South-of-Tesla extension, which is part of the COT Project MOU, there is no agreement on a definition of the COT Project.

10. Applicants have failed to provide a clear undisputed project description as required by GO 131-C.

11. Applicants' filings for certificates of public convenience and necessity were incomplete.

12. The Executive Director's determination of incompleteness was reasonable.

<u>Conclusions of Law</u>

1. The critical determination of completeness lies within the reasonable discretion of the Commission.

2. Once the Permit Streamlining Act clock starts, the Commission has only 180 days to reach a final decision from the date the applications are determined to be complete, or the project is "deemed approved."

3. The responsibilities of the Commission under the Permit Streamlining Act must be reconciled with the Commission's obligations pursuant to the Public Utilities Act.

4. The appropriate focus of a preapplication review is adequacy and completeness of the application, and not a critique of the merits of applicant's showing.

5. Given his concerns about a lack of project definition (more specifically the lack of clarity about applicants' MOU duties and obligations relative to the South of Tesla issue), the Executive Director properly determined the applications to be incomplete and there was no abuse of the discretion delegated to him by this Commission.

6. The determination of the Executive Director to reject the application(s) should be affirmed.

7. This docket should be closed, since there is no longer any matter pending before us.